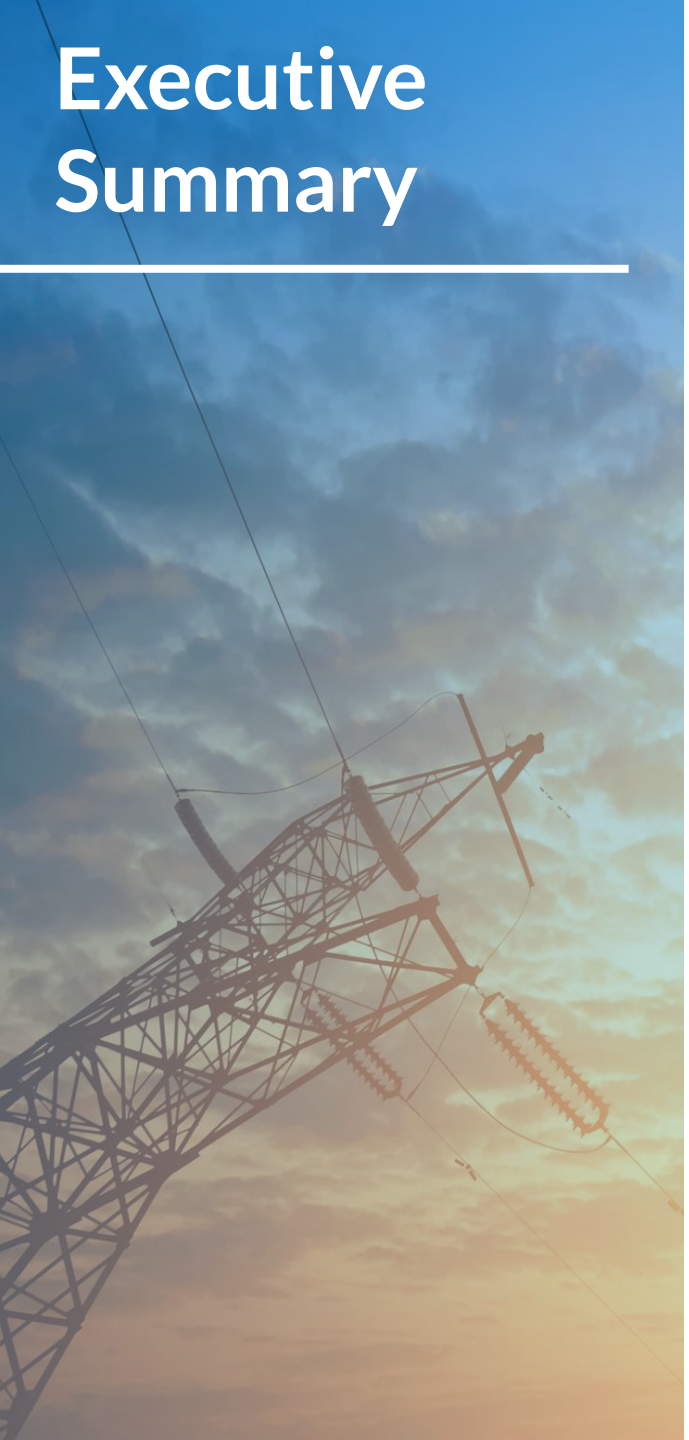
Planning Resource Auction Results for Planning Year 2026/27

April 2026

UPDATED May 22: Slides # 14-30

Executive Summary



- For the 2026 Planning Resource Auction (PRA), all zones show sufficient resources at the regional, subregional, and zonal levels to meet resource adequacy requirements across all four seasons
- The Reliability Based Demand Curve (RBDC) framework ensures a reliability-focused pricing structure that accurately reflects the reliability value of capacity above (and below) resource adequacy targets, while helping with the price stability
- The 2026 PRA has set annualized price in the range of $116 - $126 per MW-day for the 2026-2027 Planning Year
- Capacity offered into the auction increased by as much as 4% compared to last year's PRA
- New generation capacity is coming online, but faster resource additions are still needed to support large-load growth and ensure resource adequacy

MISO met the planning year 2026/27 resource adequacy requirements, with gains in offered capacity outpacing pressure of load growth on increased requirements

Summer

$424.30 (North/Central)
$384.10 (LRZs 8, 10)
$412.10 (LRZ 9)

Annualized

$126.19 (North/Central)
$116.06 (LRZs 8, 10)
$123.12 (LRZ 9)

Fall

$33.92

Winter

$35.97

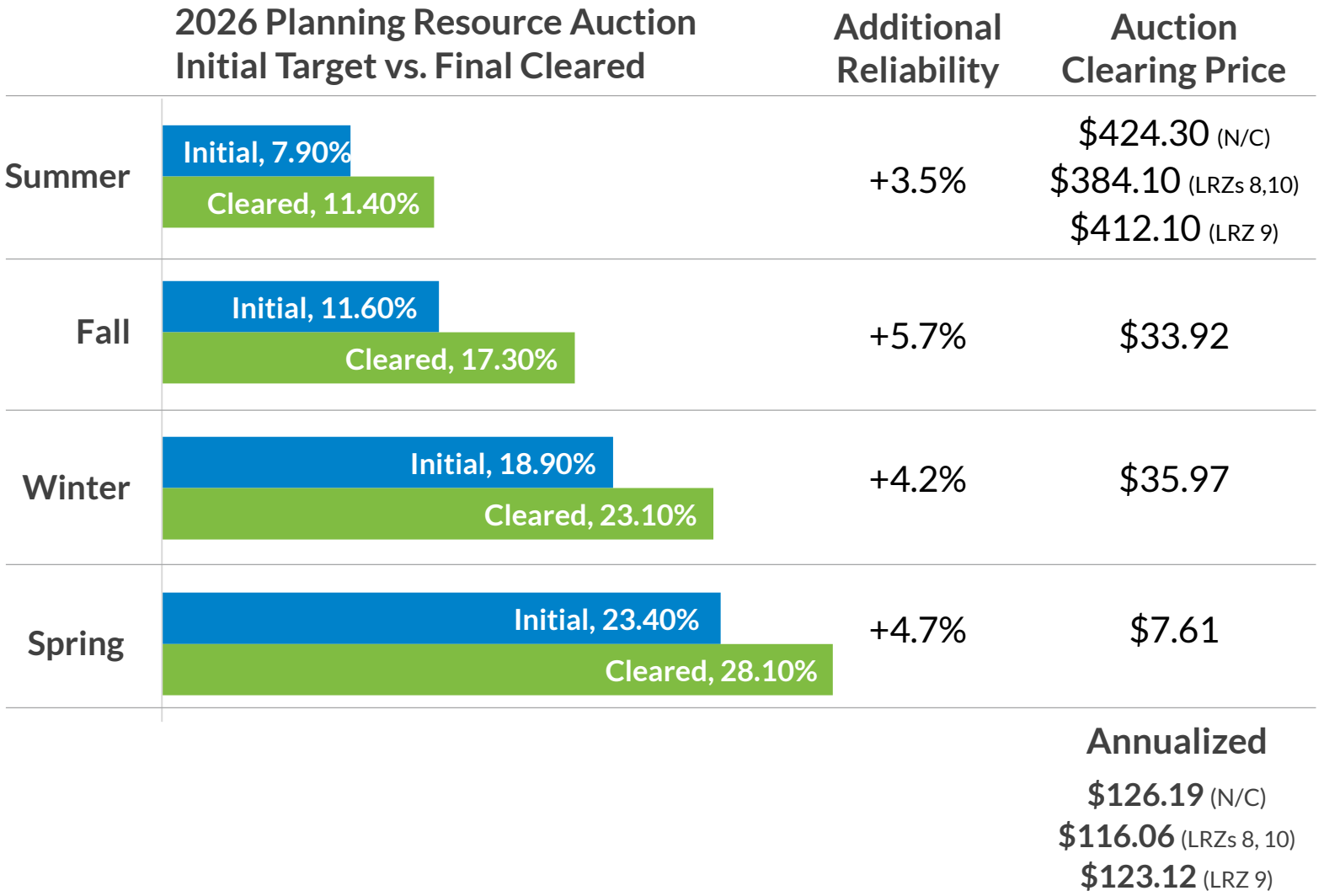
Spring

$7.61

- More capacity was offered than last year, which offset higher demand and improved reliability across seasons
- The summer auction cleared with a reserve margin 3.5 points above the 7.9% target
- Summer remains tight, so prices reflect the limited surplus available
  - Price differences were influenced by transfer limitations between the North and South
  - LRZ 9 needed more local capacity, driving a higher clearing price
- Most customers (~92%) secured capacity ahead of time or self supplied, reducing their sensitivity to auction outcomes
- The surplus above target was 2.0 GW higher than last summer, even with a +2.7 GW increase in required capacity (Initial PRMR)
- New capacity and more imports outweighed lower accreditation and retirements/suspensions
- Capacity additions need to continue, given expected growth from new large loads

MISO's RBDC improves price signals, reflecting the increased value of accredited capacity beyond seasonal reliability targets

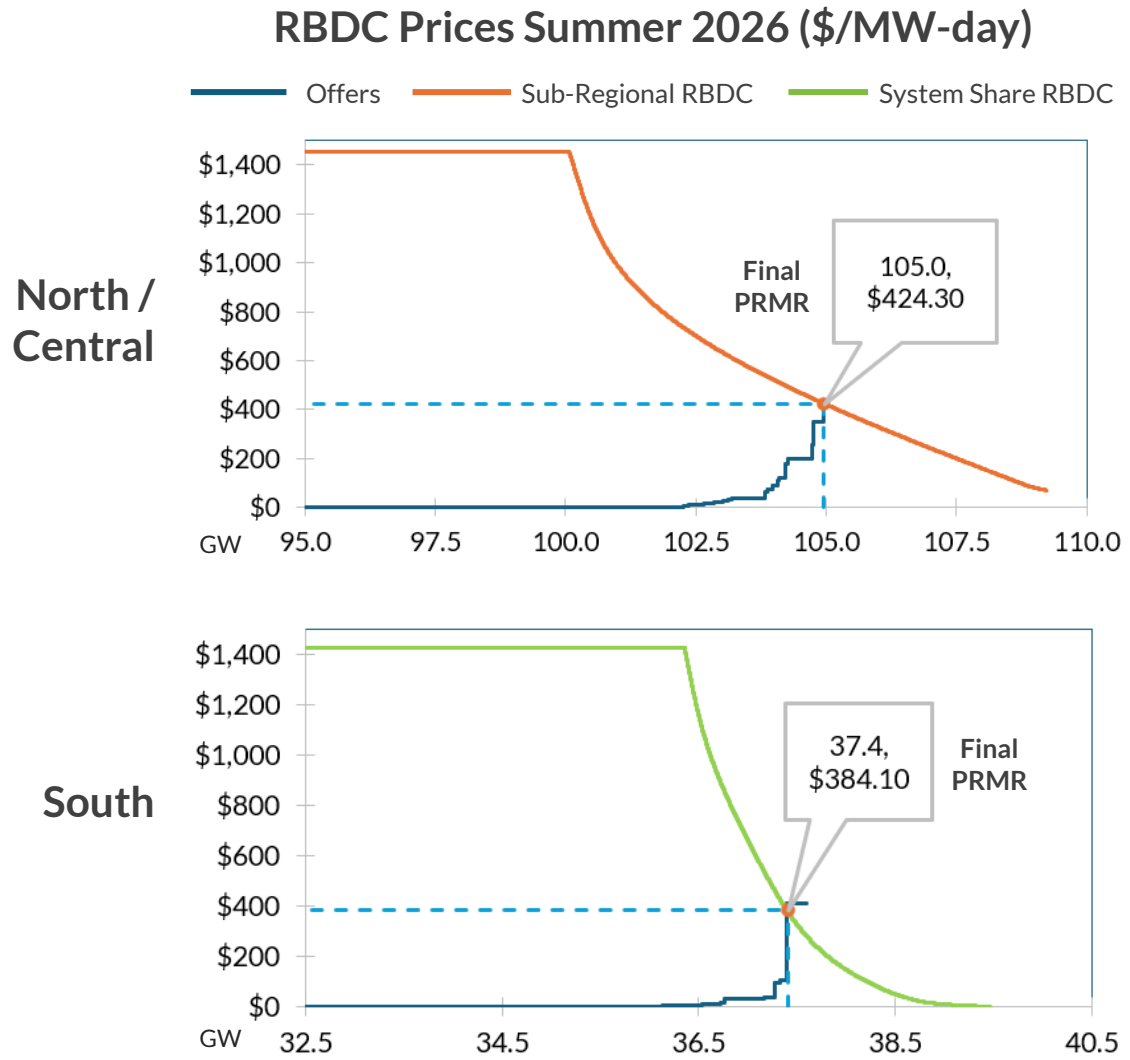
Auction cleared above seasonal initial reliability targets, representing additional reliability value at cost-competitive prices



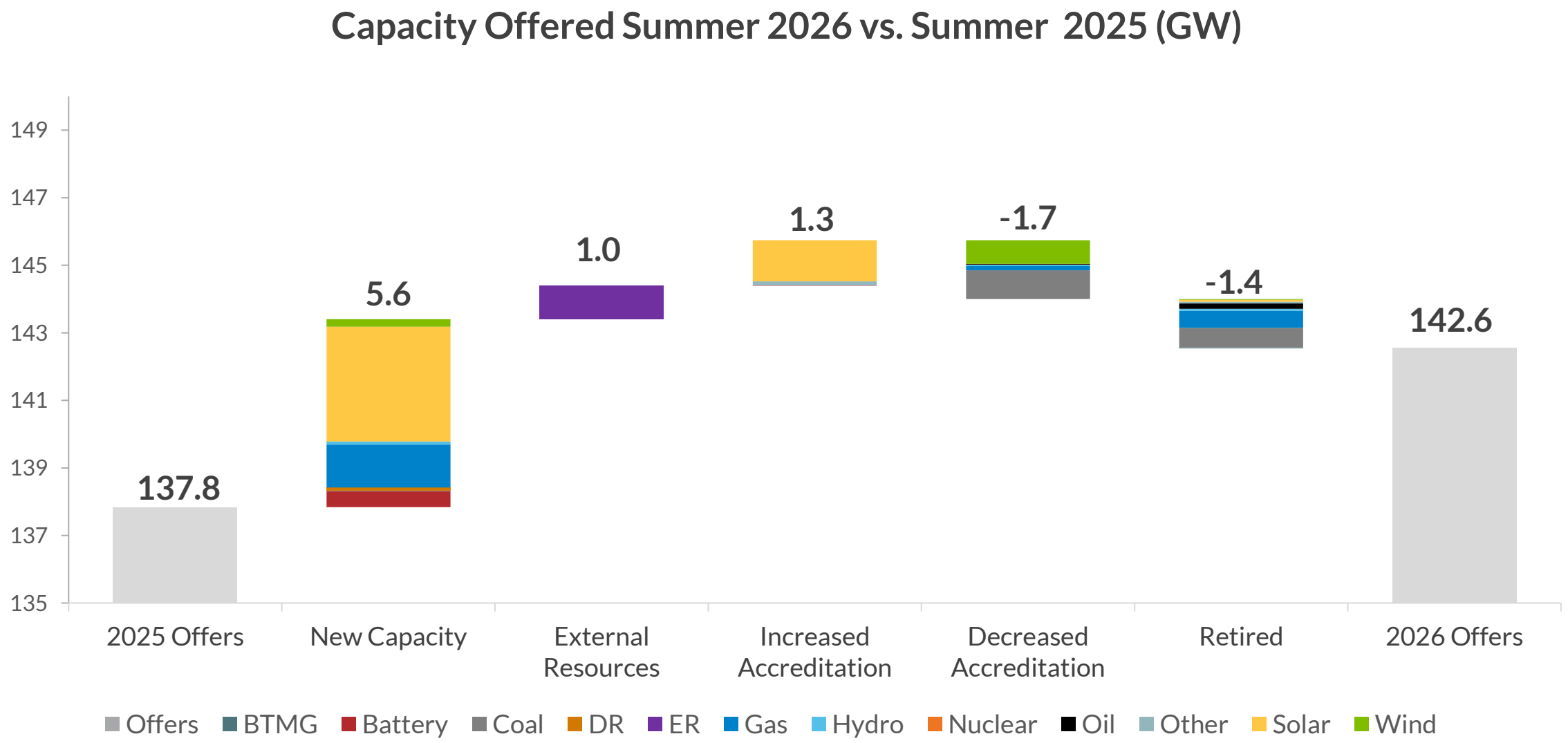
Under RBDC, each season has an initial reliability target (PRM%)

Pricing outcomes with the RBDC reflect both volume and pricing of offered capacity

- Summer clearing of $424.30 reflects highest reliability risk and increasing surplus capacity year-over-year
  - Summer surplus capacity has increased from 2.6 GW in 2025 to 4.6 GW in 2026
- Incremental capacity cleared beyond the target PRM based on the value it adds to reliability
  - Example: North/Central "effective" summer margin at 12.0% and South at 9.7% vs. target 7.9%
  - A small quantity of capacity offered at a price higher than the reliability value indicated through the demand curve did not clear
  - LRZ 9 cleared at $412.10 to satisfy LCR



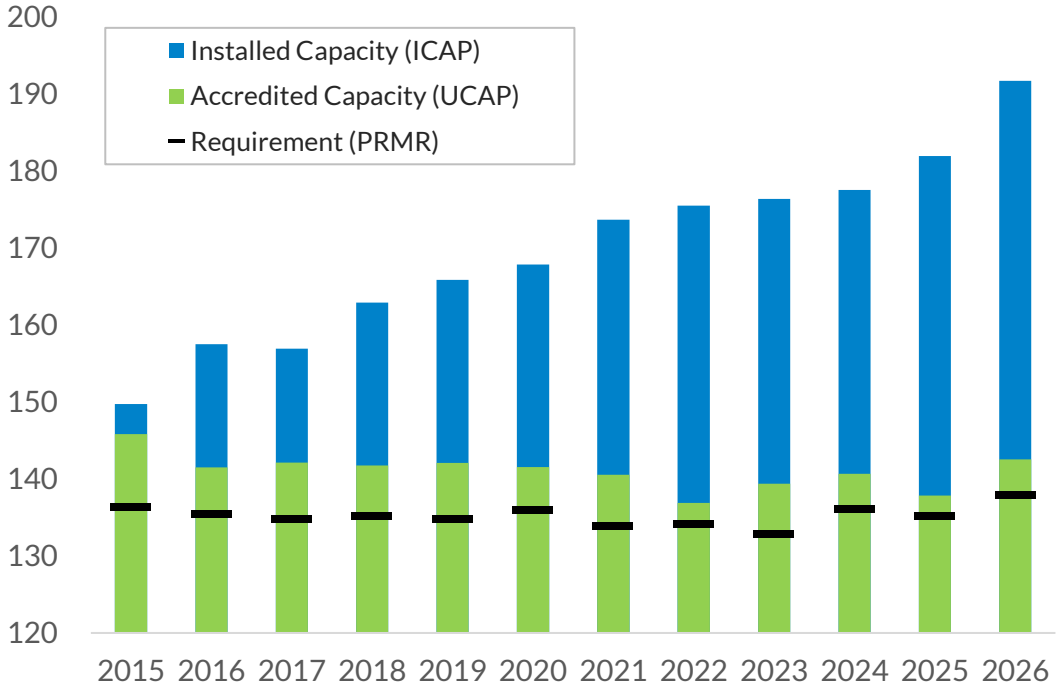
New capacity additions outpaced decreased accreditation and suspensions/retirements



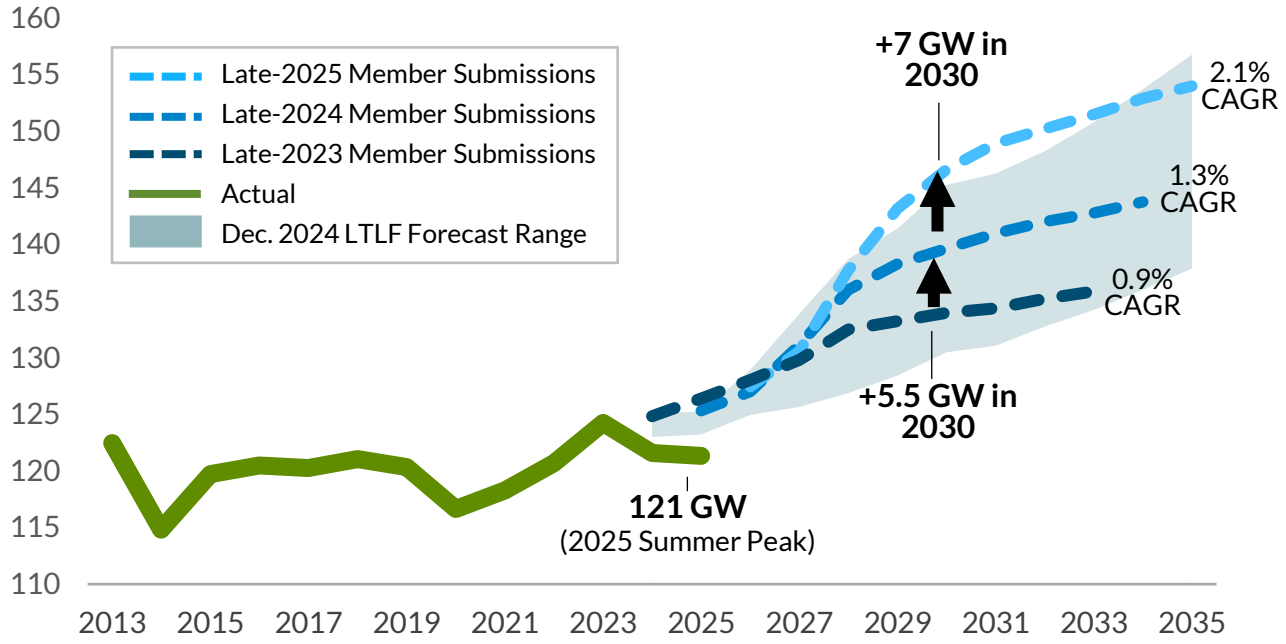
BTMG: Behind the Meter Generation. Capacity indicated is offered accredited value.

While our market reforms have helped hold the line amidst tighter reserve margin compared to the prior decade, resource adequacy remains at risk, especially as demand for large load additions accelerate

Available Capacity and Reliability Requirements from MISO Planning Resource Auctions



Recent Member and MISO Load Forecasts Net Coincident Peak (GW)



MISO has acted on many Reliability Imperative initiatives to address resource adequacy challenges, but continued collaboration on other priorities focused on readiness, speed and transparency is critical

Completed Initiatives

- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Began interim Expedited Resource Addition Study (ERAS) process *(June 2025)*
- ✓ Implemented Generation Interconnection Queue cap
- ✓ Reduced early phase of interconnection queue process
- ✓ Approved 10,570+ miles of new transmission lines

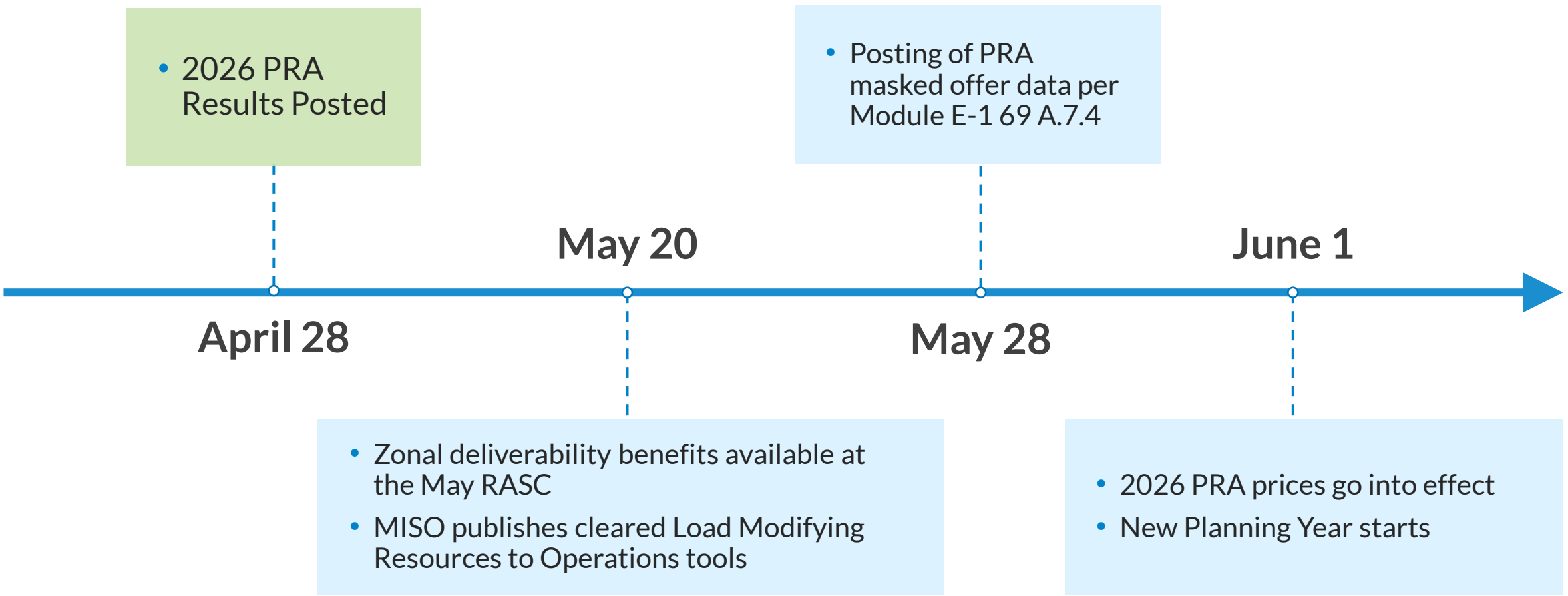
Initiatives In Progress

- Implement Direct Loss of Load (DLOL)-based accreditation
- Enhance resource adequacy risk modeling
- Improve queue cycle to 373 days
- Demand Response and Emergency Resource reforms
- Enhance allocation of resource adequacy requirements
- Reliability and Market requirements for Large Loads, Generation with Zero-Injection GIAs

Ongoing Challenges

- More frequent extreme weather
- Accelerating demand for electricity and large load interconnections
- Loss of accredited capacity and reliability attributes as resource mix evolves
- Pace of new resources additions
- Address local reliability (load pocket) issues
- Evolve storage participation

Next Steps


• 2026 PRA Results Posted
April 28
May 20
• Zonal deliverability benefits available at the May RASC
• MISO publishes cleared Load Modifying Resources to Operations tools
• Posting of PRA masked offer data per Module E-1 69 A.7.4
May 28
June 1
• 2026 PRA prices go into effect
• New Planning Year starts

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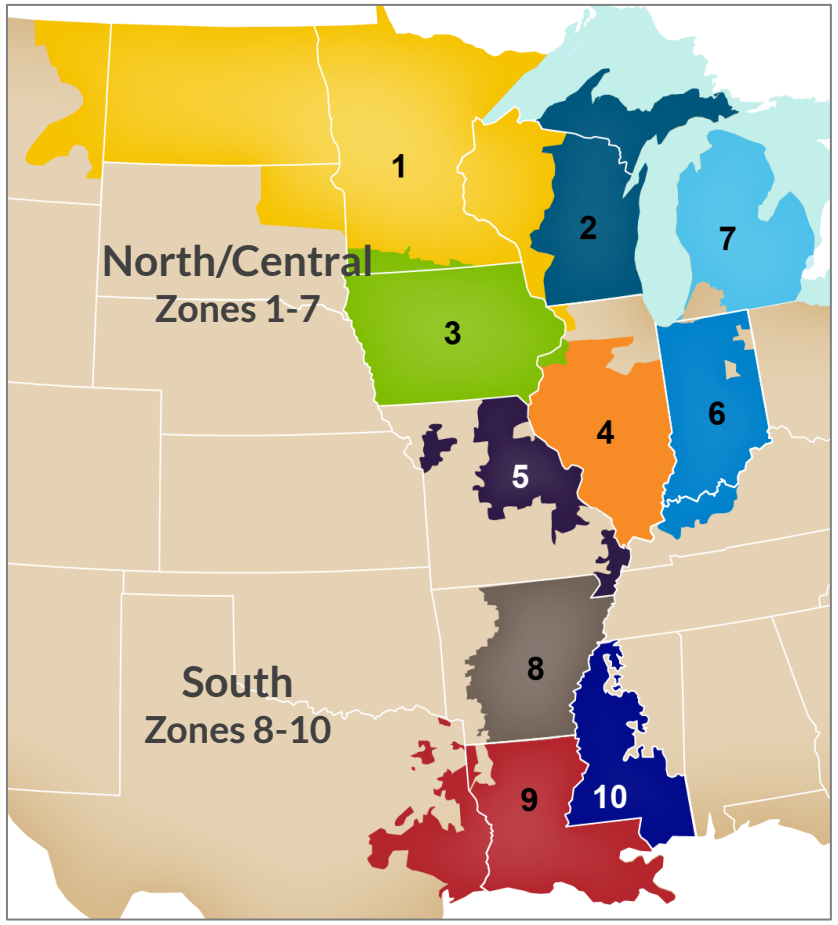
Acronyms

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 2026 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



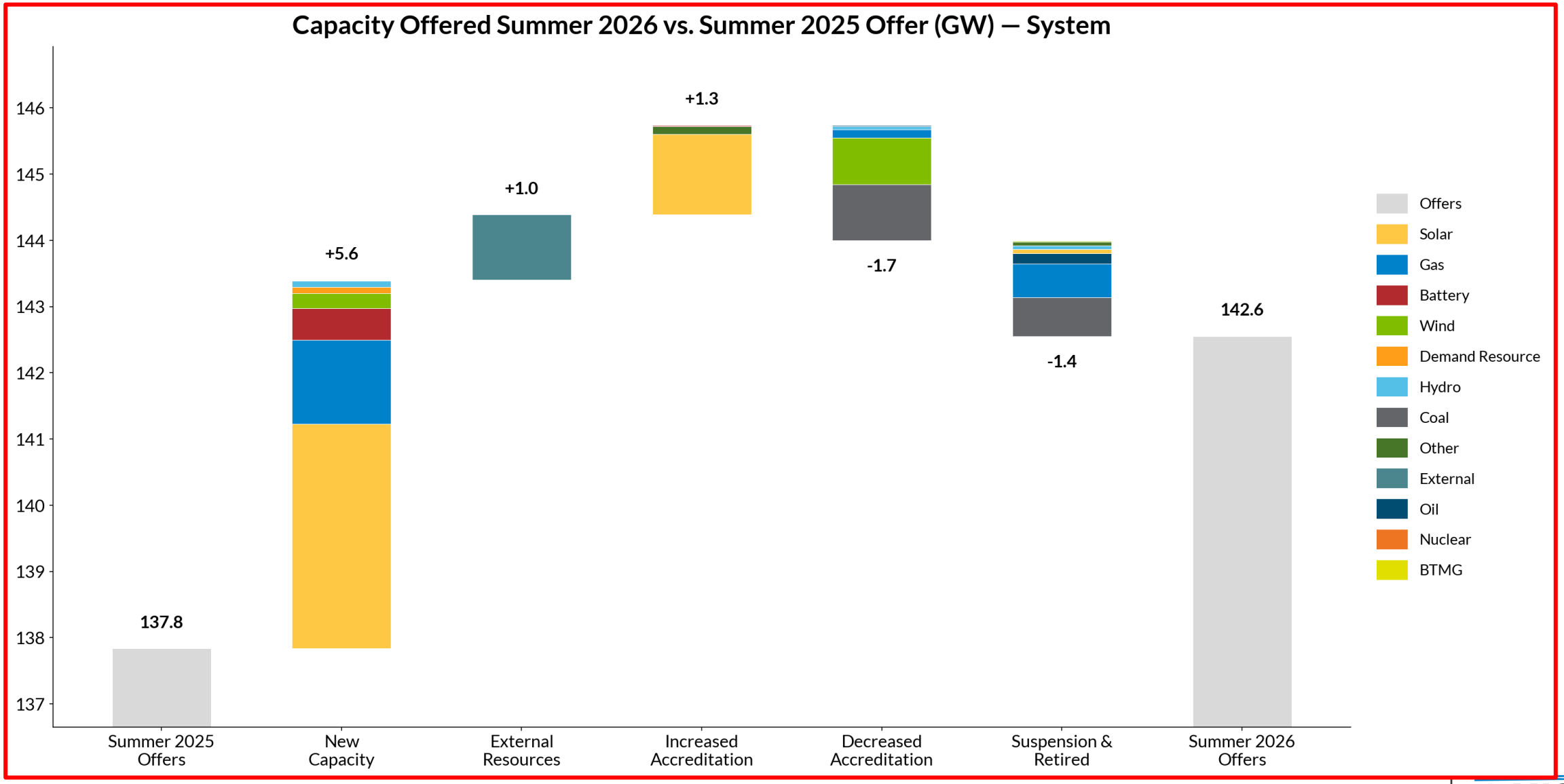
2026 PRA Results

	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	$424.30	$33.92	$35.97	$7.61
2				
3				
4				
5				
6				
7				
8	$384.10			
9	$412.10			
10	$384.10			

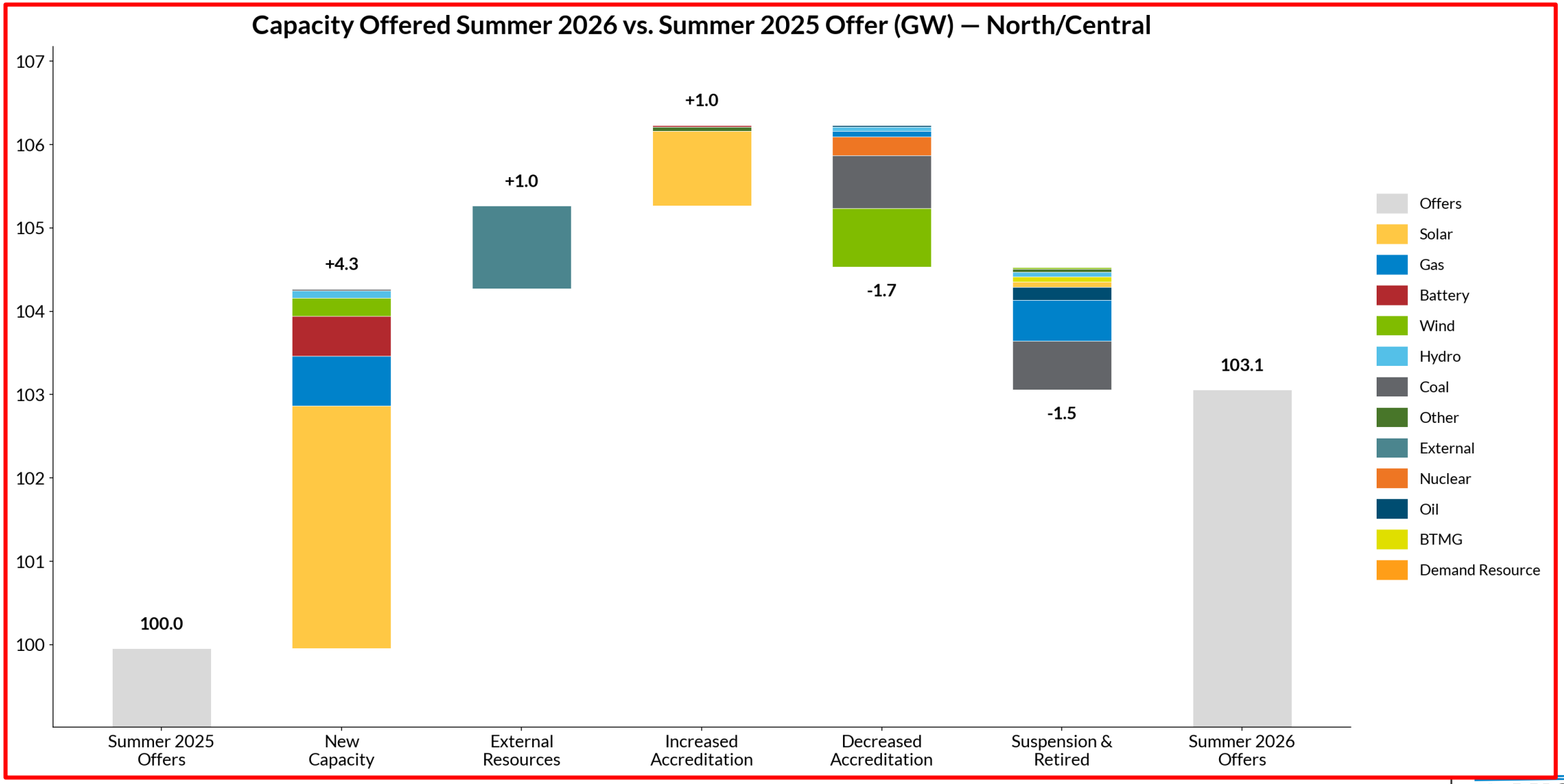
Annualized

$126.19 (N/C)
$116.06 (LRZs 8, 10)
$123.12 (LRZ 9)

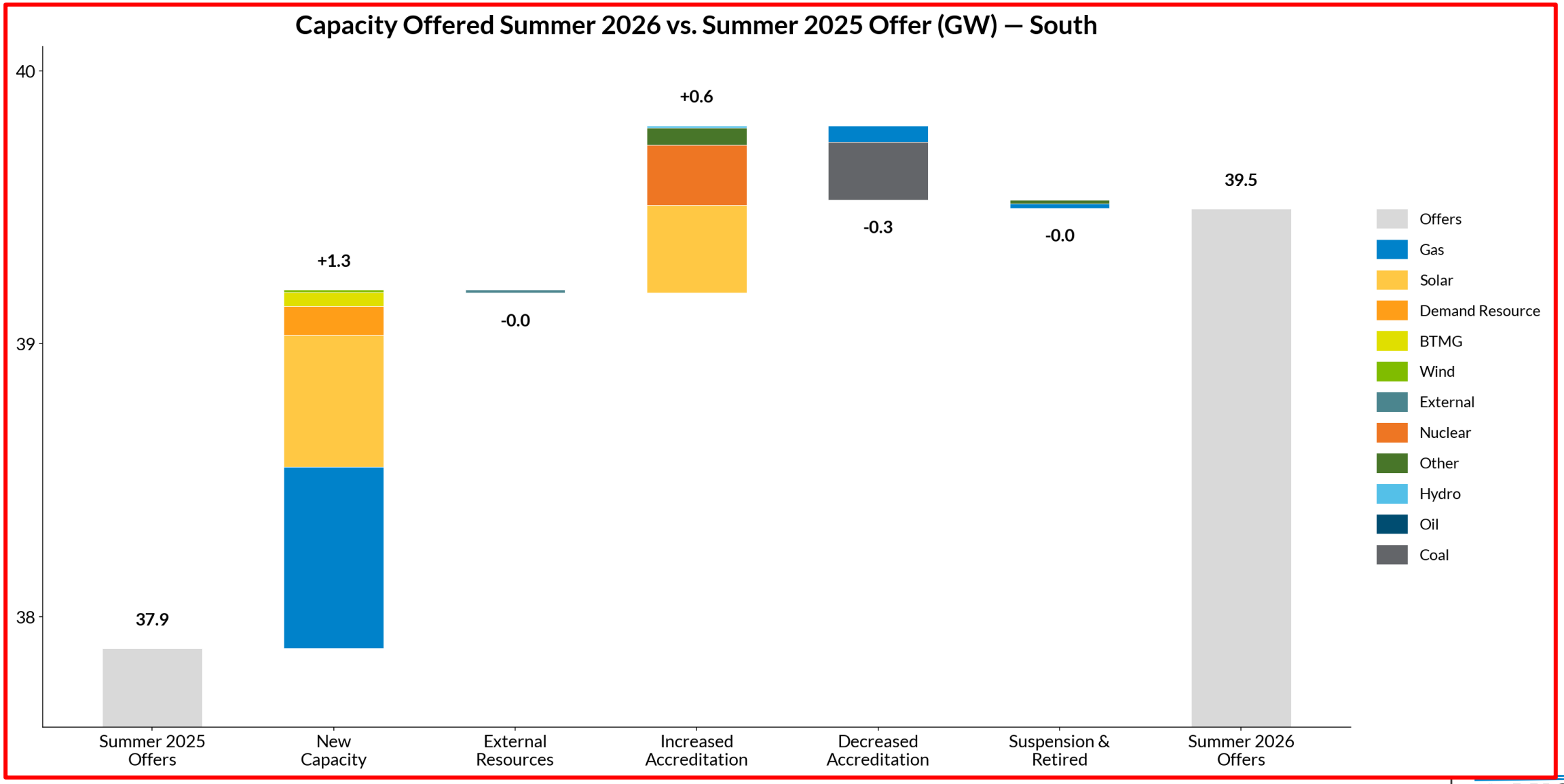
Year-over-year change in capacity offers: Summer - System



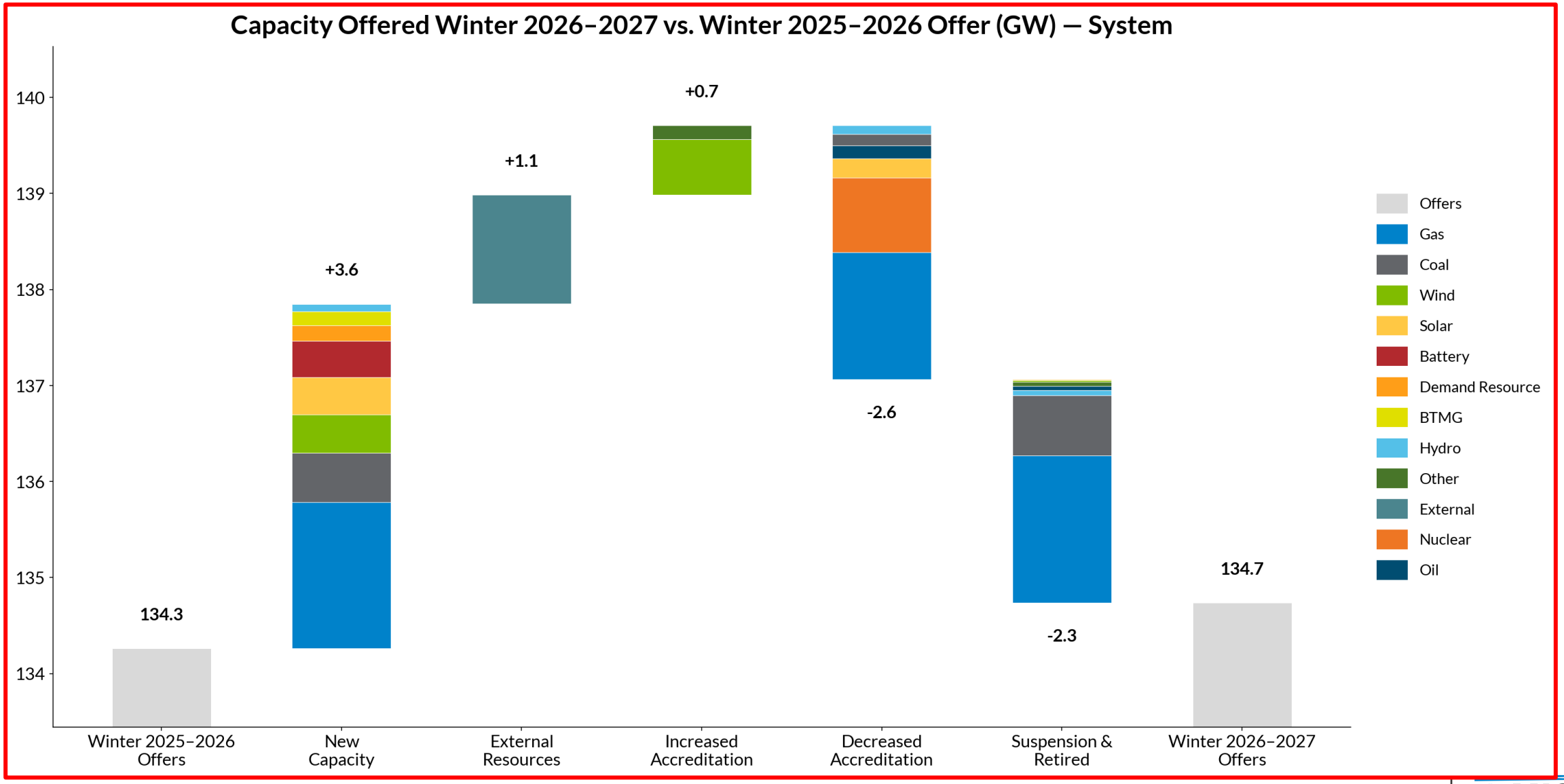
Year-over-year change in capacity offers: Summer – North/Central Subregion



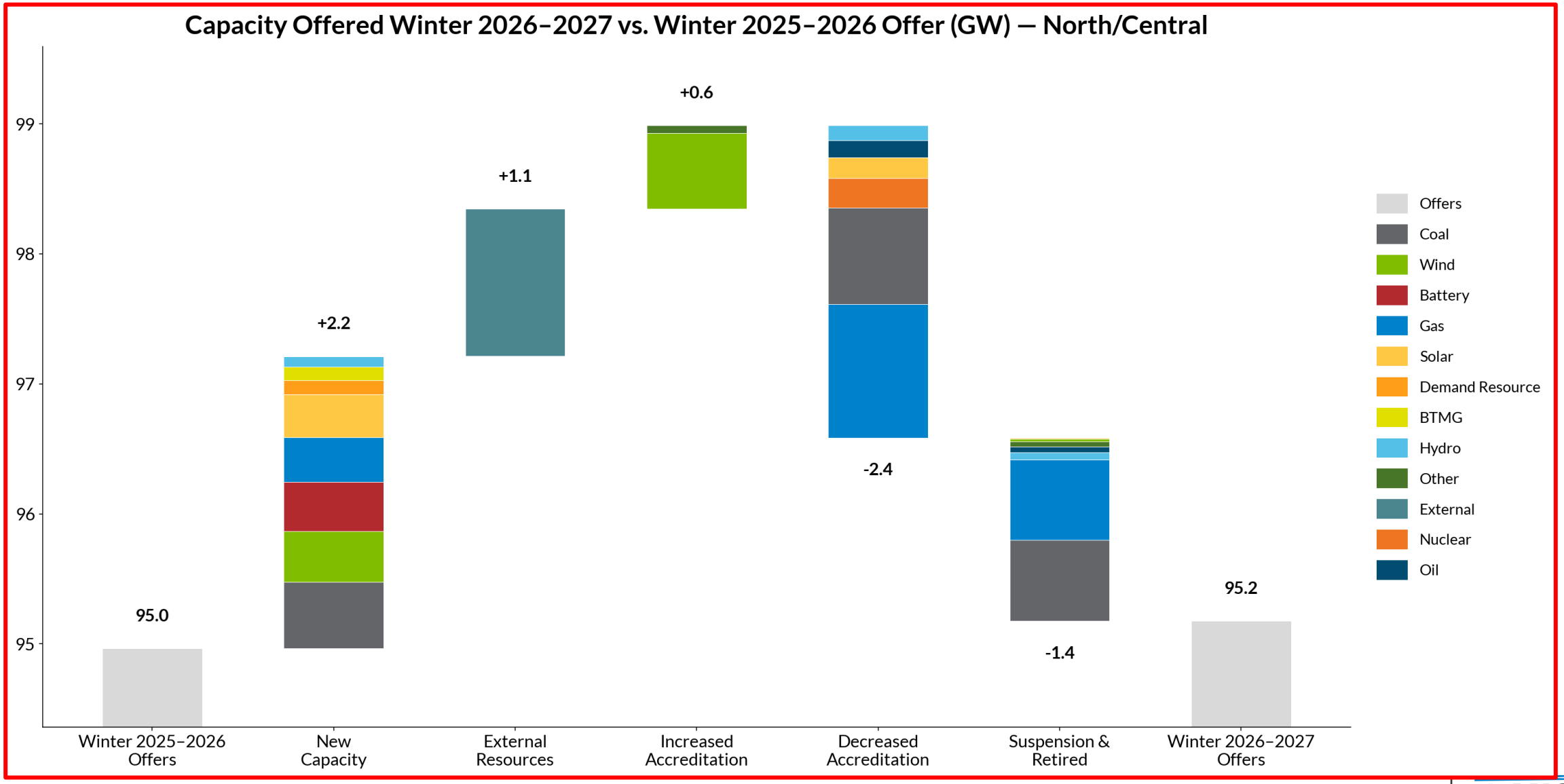
Year-over-year change in capacity offers: Summer – South Subregion



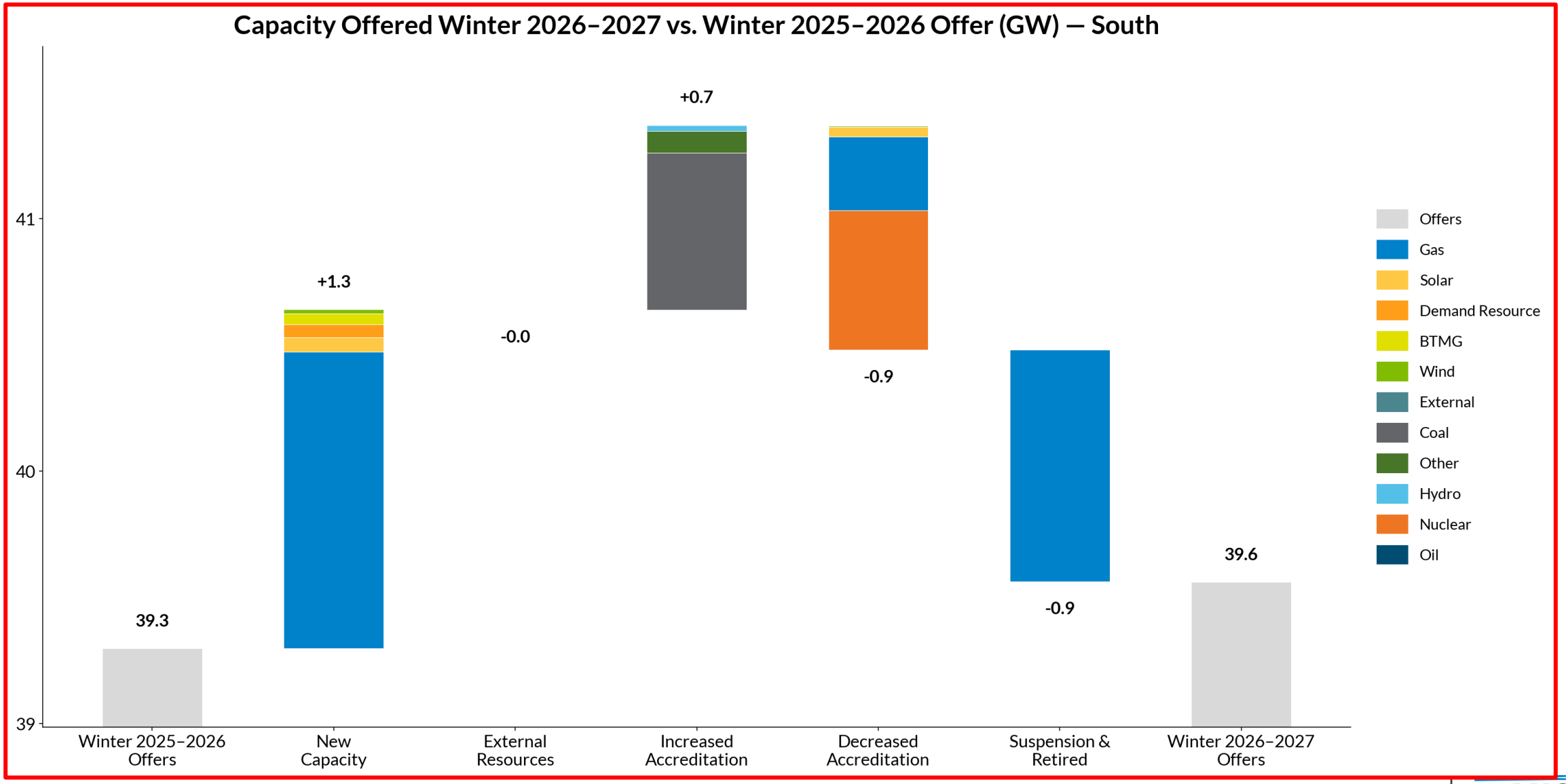
Year-over-year change in capacity offers: Winter – System



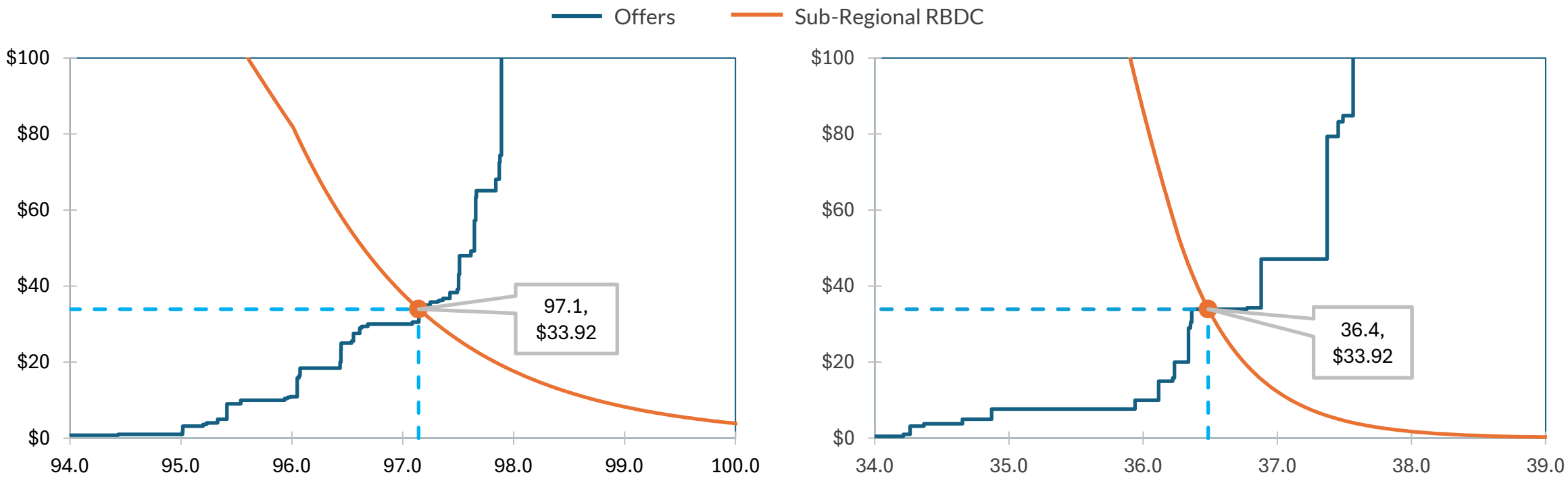
Year-over-year change in capacity offers: Winter – North/Central Subregion



Year-over-year change in capacity offers: Winter – South Subregion

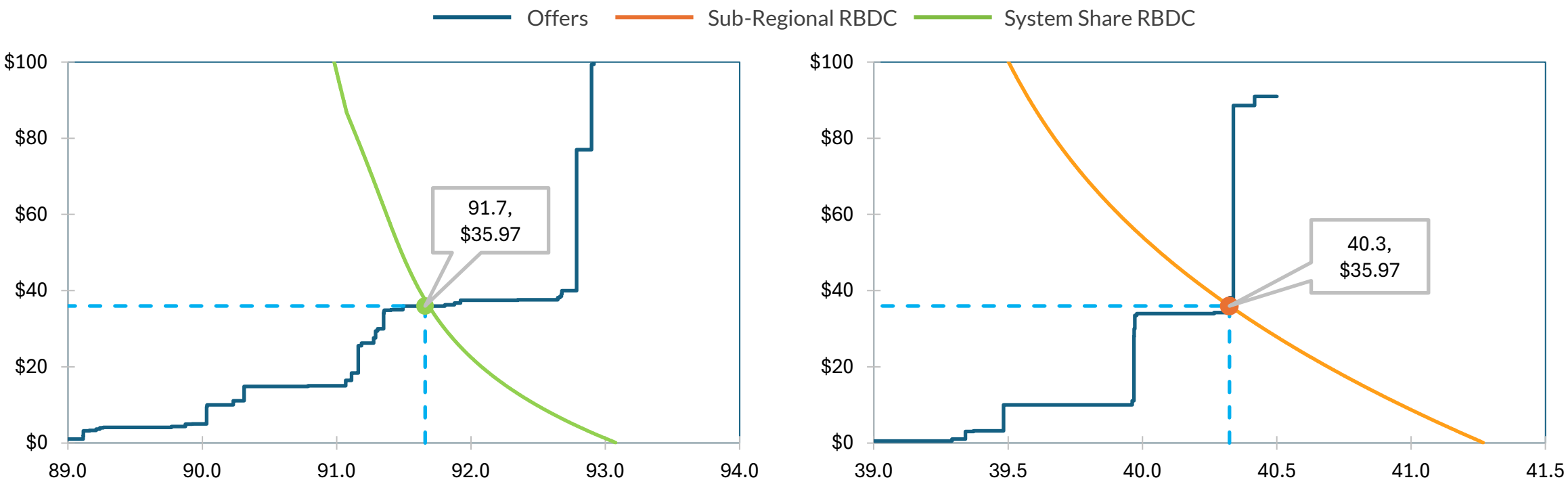


Fall 2026 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices



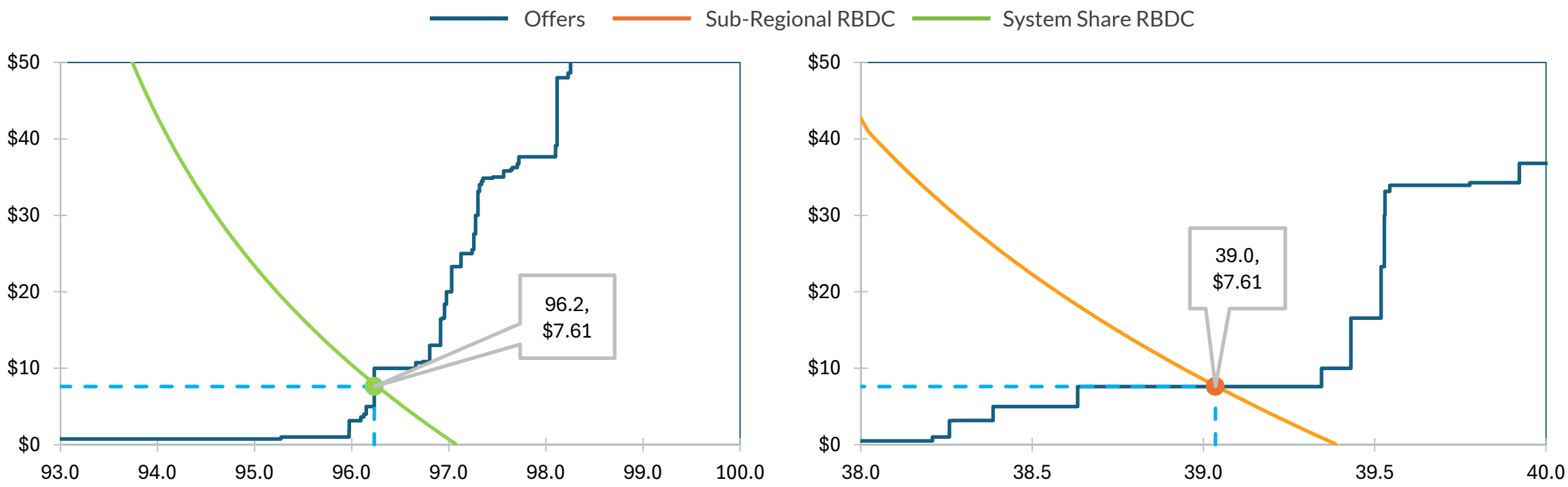
- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in fall
  - ACP for both subregions is $33.92
  - Single marginal resource in South sets the price
- In fall season, "effective" margin for North/Central subregion is at **16.7% and 18.9%** for South subregion vs. target of 11.6%

Winter 2026/27 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices



- Share of System RBDC determined clearing in the North/Central subregion
- Subregional RBDC determines clearing in the South subregion
- No price separation between North/Central and South subregions in winter
  - ACP for both subregions is $35.97; Multiple marginal resources in North/Central set the price
- In winter, "effective" margin for North/Central subregion is at **20.0% and 30.7**% for South subregion vs. target of 18.9%

Spring 2027 Reliability-Based Demand Curve, Offer Curves and Auction Clearing



- Share of System RBDC determined clearing in the North/Central subregion
- Subregional RBDC determines clearing in the South subregion
- No price separation between North/Central and South subregions in spring
  - ACP for both subregions is $7.61; Multiple marginal resources in South set the price
- In spring, "effective" margin for North/Central subregion is at **26.1% and 33.2%** for South subregion vs. target of 23.4%

Summer 2026 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ[1]	North	South	System
Initial PRMR	18,968.1	13,425.3	11,290.0	9,194.7	8,455.7	18,778.8	21,004.1	8,691.4	22,548.5	5,566.2	N/A	101,116.7	36,806.1	137,922.8
Final PRMR	19,688.5	13,935.4	11,719.1	9,543.7	8,777.4	19,492.0	21,802.2	8,835.6	22,921.9	5,658.5	N/A	104,958.3	37,416.0	142,374.3
Offer Submitted (Including FRAP)	19,568.4	15,061.4	11,298.8	10,634.6	7,119.2	16,753.8	21,403.4	11,998.8	21,368.7	5,816.8	1,529.2	103,058.3	39,494.8	142,553.1
FRAP	4,609.7	8,203.5	341.2	463.6	0.0	1,245.0	1,291.8	434.5	0.0	1,562.5	36.3	16,188.4	1,999.7	18,188.1
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-		0.0	0.0	0.0
Self Scheduled (SS)	14,641.3	6,682.7	10,725.5	8,435.5	6,934.9	10,365.0	19,814.5	11,031.1	19,109.6	3,999.3	1,141.4	78,542.5	34,338.3	112,880.8
Non-SS Offer Cleared	317.4	175.2	232.1	1,735.5	184.3	5,143.8	297.1	533.2	2,080.3	255.0	351.5	8,327.4	2,978.0	11,305.4
Committed (Offer Cleared + FRAP)	19,568.4	15,061.4	11,298.8	10,634.6	7,119.2	16,753.8	21,403.4	11,998.8	21,189.9	5,816.8	1,529.2	103,058.3	39,316.0	142,374.3
LCR	13,280.5	8,795.4	8,145.5	2,554.5	6,062.8	15,243.5	17,396.8	7,226.4	21,189.9	1,860.9	-	N/A	N/A	N/A
CIL	7,044.0	5,072.0	5,489.0	8,708.0	4,417.0	6,731.0	4,628.0	4,187.0	4,309.0	5,322.0	-	N/A	N/A	N/A
ZIA	7,042.0	5,072.0	5,400.0	8,517.0	4,417.0	6,440.0	4,628.0	3,981.0	4,309.0	5,322.0	-	N/A	N/A	N/A
Import	120.1	0.0	420.3	0.0	1,658.2	2,738.2	398.8	0.0	1,732.0	0.0	-	1,900.0	0.0	1,529.2
CEL	3,718.0	3,088.0	5,044.0	8,034.0	5,255.0	7,453.0	5,745.0	5,197.0	3,361.0	2,132.0	-	N/A	N/A	N/A
Export	0.0	1,126.0	0.0	1,090.9	0.0	0.0	0.0	3,163.2	0.0	158.3	1,529.2	0.0	1,900.0	-
ACP ($/MW-Day)	$424.30	$424.30	$424.30	$424.30	$424.30	$424.30	$424.30	$384.10	$412.10	$384.10	$405.31-$424.30	N/A	N/A	N/A

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

[1]Total ZRCs from External Resources that are not Border External Resources (BER) or Coordinating Owner Resources (COR).

Fall 2026 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ[1]	North	South	System
Initial PRMR	17,218.8	11,870.4	10,449.6	8,822.8	7,691.2	17,520.0	19,286.6	7,880.1	21,174.7	5,200.8	N/A	92,859.4	34,255.6	127,115.0
Final PRMR	18,012.8	12,418.2	10,931.4	9,230.0	8,046.1	18,328.3	20,177.0	8,393.1	22,552.9	5,539.0	N/A	97,143.8	36,485.0	133,628.8
Offer Submitted (Including FRAP)	19,290.8	14,299.1	12,531.4	9,984.5	7,153.6	15,241.1	20,491.1	11,634.5	21,268.3	5,528.8	1,527.1	100,225.7	38,724.6	138,950.3
FRAP	4,201.3	7,027.2	343.6	445.7	0.0	1,095.3	1,246.9	403.2	0.0	1,367.1	34.1	14,392.5	1,771.9	16,164.4
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-		0.0	0.0	0.0
Self Scheduled (SS)	13,841.9	6,748.2	11,775.2	7,843.7	6,937.7	9,526.1	18,027.5	9,845.0	16,494.1	3,833.8	1,084.4	75,599.5	30,358.1	105,957.6
Non-SS Offer Cleared	700.5	426.7	314.3	1,621.7	179.5	3,810.7	241.1	493.7	3,195.2	180.8	342.6	7,530.9	3,975.9	11,506.8
Committed (Offer Cleared + FRAP)	18,743.7	14,202.1	12,433.1	9,911.1	7,117.2	14,432.1	19,515.5	10,741.9	19,689.3	5,381.7	1,461.1	97,522.9	36,105.9	133,628.8
LCR	12,057.3	6,520.8	4,424.1	3,397.9	5,160.5	13,479.1	16,133.1	5,090.4	19,222.5	2,018.4	-	N/A	N/A	N/A
CIL	7,297.0	6,050.0	9,283.0	6,673.0	4,762.0	7,301.0	5,193.0	6,336.0	4,761.0	4,379.0	-	N/A	N/A	N/A
ZIA	7,245.0	6,050.0	9,191.0	6,491.0	4,762.0	7,012.0	5,193.0	6,170.0	4,761.0	4,379.0	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	0.0	928.9	3,896.2	661.5	0.0	2,863.6	157.3	-	0.0	379.1	1,461.1
CEL	4,147.0	5,034.0	5,652.0	6,429.0	3,701.0	5,172.0	5,305.0	3,781.0	3,970.0	2,459.0	-	N/A	N/A	N/A
Export	730.9	1,783.9	1,501.7	681.1	0.0	0.0	0.0	2,348.8	0.0	0.0	1,461.1	379.1	0.0	-
ACP ($/MW-Day)	$33.92	$33.92	$33.92	$33.92	$33.92	$33.92	$33.92	$33.92	$33.92	$33.92	$33.92	N/A	N/A	N/A

Values displayed in MW SAC; ERZ: External Resource Zones. Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.
[1]Total ZRCs from External Resources that are not Border External Resources (BER) or Coordinating Owner Resources (COR).

Winter 2026/27 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ[1]	North	South	System
Initial PRMR	18,112.7	11,417.0	10,727.8	8,550.7	8,155.2	18,198.5	15,627.5	8,783.0	22,413.9	5,489.4	N/A	90,789.4	36,686.3	127,475.7
Final PRMR	18,285.9	11,526.7	10,831.0	8,632.3	8,233.4	18,372.6	15,776.8	9,653.8	24,636.2	6,033.8	N/A	91,658.7	40,323.8	131,982.5
Offer Submitted (Including FRAP)	18,976.4	13,305.7	12,736.1	8,210.2	6,246.9	14,617.0	19,647.2	10,982.4	22,518.4	5,730.2	1,766.8	95,177.6	39,559.7	134,737.3
FRAP	4,741.7	6,654.8	334.9	424.6	0.0	1,126.1	1,168.6	458.8	0.0	1,681.4	35.9	14,484.7	2,142.1	16,626.8
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-		0.0	0.0	0.0
Self Scheduled (SS)	13,674.5	6,243.9	12,146.0	6,735.5	6,153.3	7,898.8	16,240.9	10,326.7	20,995.4	3,998.1	1,360.4	70,239.9	35,533.6	105,773.5
Non-SS Offer Cleared	515.2	259.5	255.2	979.5	90.2	5,119.3	414.7	196.9	1,360.8	50.7	340.0	7,874.3	1,707.7	9,582.0
Committed (Offer Cleared + FRAP)	18,931.4	13,158.2	12,736.1	8,139.6	6,243.5	14,144.2	17,824.2	10,982.4	22,356.2	5,730.2	1,736.3	92,598.9	39,383.4	131,982.3
LCR	13,639.8	7,123.9	5,013.8	3,090.6	1,890.3	11,080.7	14,688.8	8,021.3	21,311.9	3,756.4	-	N/A	N/A	N/A
CIL	5,135.0	5,379.0	9,724.0	5,682.0	6,379.0	8,499.0	4,123.0	3,544.0	3,690.0	3,154.0	-	N/A	N/A	N/A
ZIA	4,533.0	5,294.0	9,620.0	5,493.0	6,379.0	8,208.0	4,123.0	3,366.0	3,690.0	3,154.0	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	492.7	1,989.9	4,228.4	0.0	0.0	2,280.0	303.6	-	0.0	940.4	1,736.3
CEL	2,385.0	3,860.0	9,181.0	4,535.0	6,786.0	3,087.0	5,546.0	4,431.0	2,096.0	1,602.0	-	N/A	N/A	N/A
Export	645.5	1,631.5	1,905.1	0.0	0.0	0.0	2,047.4	1,328.6	0.0	0.0	1,736.3	940.2	0.0	-
ACP ($/MW-Day)	$35.97	$35.97	$35.97	$35.97	$35.97	$35.97	$35.97	$35.97	$35.97	$35.97	$35.97	N/A	N/A	N/A

Values displayed in MW SAC; ERZ: External Resource Zones. Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.
[1]Total ZRCs from External Resources that are not Border External Resources (BER) or Coordinating Owner Resources (COR).

Spring 2027 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ[1]	North	South	System
Initial PRMR	17,840.4	12,483.5	10,640.6	7,773.7	7,828.4	17,981.9	19,625.5	8,074.8	22,644.1	5,431.1	N/A	94,174.0	36,150.0	130,324.0
Final PRMR	18,230.6	12,756.1	10,873.3	7,943.3	7,999.5	18,375.1	20,054.3	8,719.1	24,451.4	5,864.4	N/A	96,232.2	39,034.9	135,267.1
Offer Submitted (Including FRAP)	18,619.7	15,445.5	11,520.6	10,895.8	7,288.4	16,078.3	20,721.0	12,186.6	21,295.8	6,216.2	1,420.9	101,683.7	40,005.1	141,688.8
FRAP	4,416.3	7,372.7	336.0	454.4	0.0	1,125.1	1,309.9	298.6	0.0	1,471.5	34.9	15,047.7	1,771.7	16,819.4
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-		0.0	0.0	0.0
Self Scheduled (SS)	13,460.0	7,952.9	10,781.3	8,595.3	6,995.9	9,691.5	18,445.6	9,727.2	18,812.3	4,333.1	945.7	76,680.8	33,060.0	109,740.8
Non-SS Offer Cleared	321.7	50.0	260.4	1,293.9	164.0	4,090.8	444.0	811.1	1,055.0	126.5	89.5	6,714.3	1,992.6	8,706.9
Committed (Offer Cleared + FRAP)	18,198.0	15,375.6	11,377.7	10,343.6	7,159.9	14,907.4	20,199.5	10,836.9	19,867.3	5,931.1	1,070.1	98,442.9	36,824.2	135,267.1
LCR	10,315.9	6,052.3	3,341.2	2,117.6	4,087.4	10,895.5	15,143.0	5,946.1	19,442.6	2,929.7	-	N/A	N/A	N/A
CIL	6,892.0	6,133.0	9,420.0	6,732.0	4,733.0	8,324.0	5,338.0	5,566.0	4,657.0	4,187.0	-	N/A	N/A	N/A
ZIA	6,690.0	6,133.0	9,311.0	6,533.0	4,733.0	7,999.0	5,338.0	5,374.0	4,657.0	4,187.0	-	N/A	N/A	N/A
Import	32.6	0.0	0.0	0.0	839.6	3,467.7	0.0	0.0	4,584.1	0.0	-	0.0	2,210.7	1,070.1
CEL	3,513.0	4,608.0	6,282.0	6,248.0	5,811.0	4,140.0	5,497.0	3,952.0	4,633.0	2,725.0	-	N/A	N/A	N/A
Export	0.0	2,619.5	504.4	2,400.3	0.0	0.0	145.2	2,117.8	0.0	66.7	1,070.1	2,210.7	0.0	-
ACP ($/MW-Day)	$7.61	$7.61	$7.61	$7.61	$7.61	$7.61	$7.61	$7.61	$7.61	$7.61	$7.61	N/A	N/A	N/A

Values displayed in MW SAC; ERZ: External Resource Zones. Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.
[1]Total ZRCs from External Resources that are not Border External Resources (BER) or Coordinating Owner Resources (COR).

Summer Supply Offered and Cleared Comparison Trend

Planning Resource	Offered (ZRC)				Cleared (ZRC)			
	Summer 2023	Summer 2024	Summer 2025	Summer 2026	Summer 2023	Summer 2024	Summer 2025	Summer 2026
Generation	122,375.6	123,277.8	121,015.6	124,690.1	116,989.7	119,361.4	120,738.6	124,511.3
External Resources[1]	4,514.6	4,430.4	3,505.9	4,490.6	4,072.5	4,309.8	3,505.9	4,490.6
Behind the Meter Generation	4,175.2	4,180.2	4,282.8	4,272.9	4,129.4	4,143.5	4,282.8	4,272.9
Demand Resources	8,303.5	8,618.3	9,004.4	9,099.5	7,694.6	8,067.5	9,004.4	9,099.5
Energy Efficiency	5.0	22.5	27.6	0.0	5.0	22.5	27.6	0.0
Total	**139,373.9**	**140,529.2**	**137,836.3**	**142,553.1**	**132,891.2**	**135,904.7**	**137,559.3**	**142,374.3**

ZRC: Zonal Resource Credit

[1]Total ZRC/SAC for all External Resources (including BER and COR)

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)				Cleared (ZRC)			
Planning Resource	Fall 2023	Fall 2024	Fall 2025	Fall 2026	Fall 2023	Fall 2024	Fall 2025	Fall 2026
Generation	121,403.5	119,627.5	122,283.4	123,289.3	111,713.8	111,673.7	118,309.5	118,561.2
External Resources[1]	4,095.4	4,366.8	2,833.5	3,846.2	3,979.6	3,990.2	2,763.6	3,780.2
Behind the Meter Generation	3,874.2	3,877.9	3,646.8	3,925.0	3,842.8	3,789.7	3,646.8	3,923.0
Demand Resources	7,004.2	6,824.2	7,983.7	7,889.8	6,254.4	5,915.6	7,767.8	7,364.4
Energy Efficiency	4.9	22.5	28.1	0.0	4.8	22.5	28.1	0.0
Total	**136,382.2**	**134,718.9**	**136,775.5**	**138,950.3**	**125,795.4**	**125,391.7**	**132,515.8**	**133,628.8**

ZRC: Zonal Resource Credit
[1]Total ZRC/SAC for all External Resources (including BER and COR)

Winter Supply Offered and Cleared Comparison Trend

Planning Resource	Offered (ZRC)				Cleared (ZRC)			
	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026	Winter 2027-2026	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026	Winter 2026-2027
Generation	124,632.7	132,844.3	120,225.1	119,295.9	114,886.6	117,640.7	117,392.0	117,053.4
External Resources[1]	3,937.1	3,973.0	2,808.7	3,941.5	3,334.6	3,313.3	2,793.7	3,911.0
Behind the Meter Generation	3,257.8	3,111.5	3,082.9	3,228.3	3,173.9	2,957.3	3,082.6	3,228.3
Demand Resources	7,648.2	7,818.6	8,112.3	8,271.6	6,702.4	6,774.9	7,698.3	7,789.6
Energy Efficiency	6.7	29.7	32.9	0.0	6.7	29.7	32.9	0.0
Total	**139,482.5**	**147,777.1**	**134,261.9**	**134,737.3**	**128,104.2**	**130,715.9**	**130,999.5**	**131,982.3**

ZRC: Zonal Resource Credit
[1]Total ZRC/SAC for all External Resources (including BER and COR)

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)				Cleared (ZRC) [1]			
Planning Resource	Spring 2024	Spring 2025	Spring 2026	Spring 2027	Spring 2024	Spring 2025	Spring 2026	Spring 2027
Generation	119,254.7	121,303.8	120,780.6	125,637.7	110,195.8	113,091.4	115,724.7	120,373.9
External Resources[1]	3,794.1	3,481.8	2,640.1	3,527.3	3,409.1	3,406.5	2,570.3	3,076.5
Behind the Meter Generation	4,096.4	4,201.6	4,133.5	4,263.8	4,058.9	4,180.5	4,133.5	4,240.2
Demand Resources	7,287.7	7,602.9	8,475.9	8,260.0	6,720.0	7,087.2	8,240.5	7,576.5
Energy Efficiency	5.3	25.0	30.5	0.0	5.3	25.0	30.5	0.0
Total	**134,438.2**	**136,615.1**	**136,060.6**	**141,688.8**	**124,389.1**	**127,790.6**	**130,699.5**	**135,267.1**

ZRC: Zonal Resource Credit
[1]Total ZRC/SAC for all External Resources (including BER and COR)

2026 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 2026	$424.30							$384.10	$412.10	$384.10	$405.31-$424.30	$1,422.37	$1,453.99	$1,348.59
Fall 2026	$33.92											$1,422.37	$1,453.99	$1,348.59
Winter 2026-27	$35.97											$1,422.37	$1,453.99	$1,348.59
Spring 2027	$7.61											$1,422.37	$1,453.99	$1,348.59
Cost of New Entry (Annual)	$134,160	$131,310	$127,330	$132,380	$142,970	$130,710	$137,510	$125,070	$123,890	$123,250	$142,970			
IMM Conduct Threshold*	$36.76	$35.98	$34.88	$36.27	$39.17	$35.81	$37.67	$34.27	$33.94	$33.77	-			

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

Zonal Auction Clearing Prices (ACP) shown in $/MW-day. ERZ: External Resource Zones.

Historical Summer Auction Clearing Price Comparison ($/MW-Day)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2015-2016		$3.48		$150.00		$3.48		$3.29		N/A	N/A
2016-2017	$19.72			$72.00				$2.99			N/A
2017-2018					$1.50						N/A
2018-2019	$1.00				$10.00						N/A
2019-2020				$2.99			$24.30	$2.99			
2020-2021				$5.00			$257.53	$4.75	$6.88	$4.75	$4.89-$5.00
2021-2022				$5.00				$0.01			$2.78-$5.00
2022-2023				$236.66				$2.88			$2.88-236.66
Summer 2023					$10.00						
Summer 2024					$30.00						
Summer 2025					$666.50						
Summer 2026				$424.30				$384.10	$412.10	$384.10	$405.31-$424.30

ERZ: External Resource Zones.

Fall Auction Clearing Price Comparison ($/MW-Day)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
Fall 2025	$91.60							$74.09			$83.24-$91.60
Fall 2026	$33.92										

ERZ: External Resource Zones.

Winter Auction Clearing Price Comparison ($/MW-Day)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										
Winter 2026-27	$35.97										

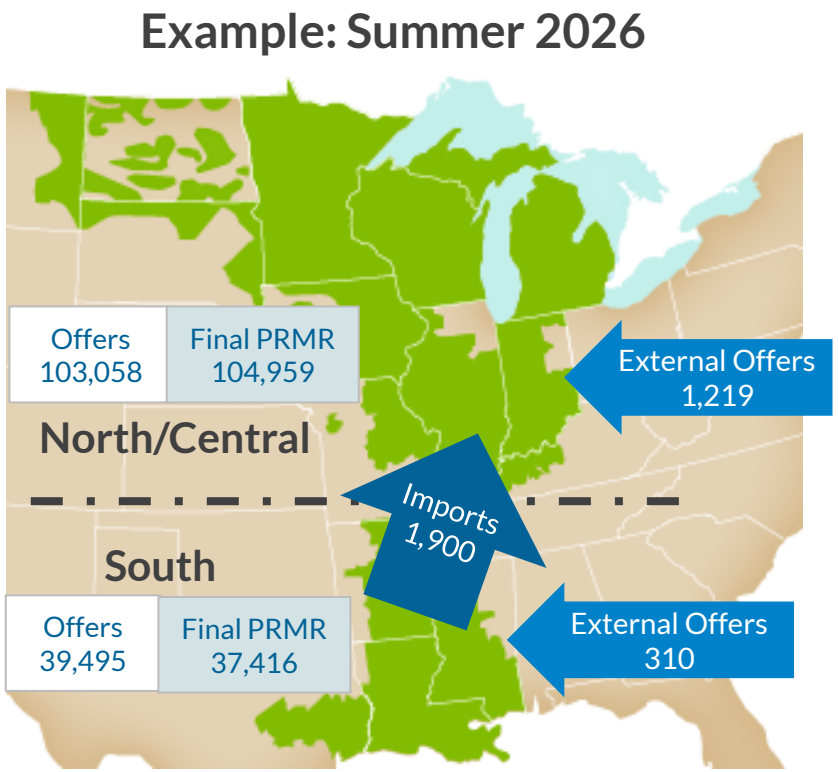
ERZ: External Resource Zones.

Spring Auction Clearing Price Comparison ($/MW-Day)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										
Spring 2027	$7.61										

ERZ: External Resource Zones.

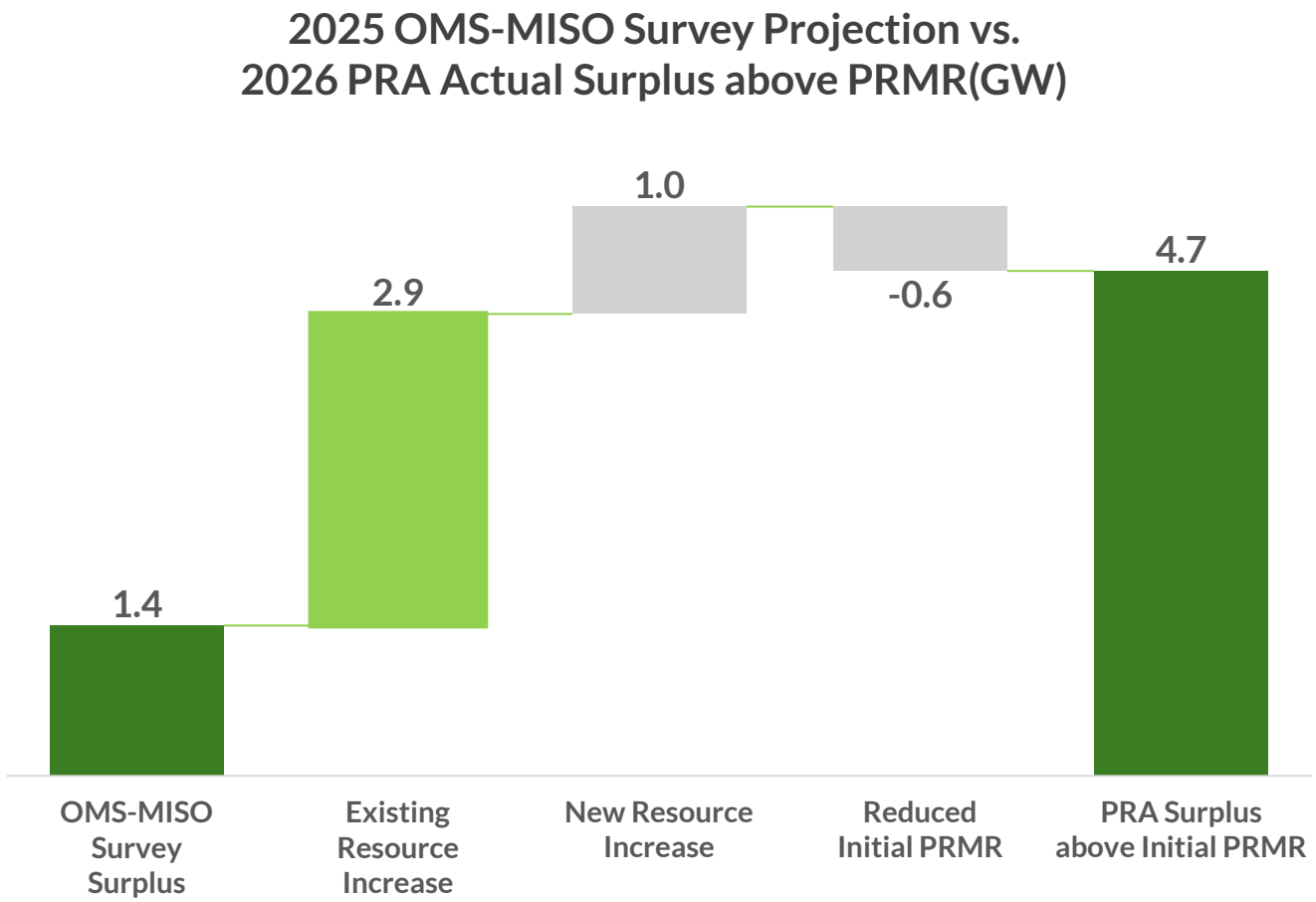
Offered Capacity, Final PRMR, Imports & Exports (MW)



	Subregion	External Offers	Total Offers	Final PRMR	Imports	Exports
Summer	North/Central	1,219	103,058	104,959	1,900	-
	South	310	39,495	37,416	-	1,900
Fall	North/Central	1,234	100,226	97,144	-	379
	South	293	38,725	36,485	379	-
Winter	North/Central	1,422	95,178	91,659	-	940
	South	315	39,560	40,234	940	-
Spring	North/Central	881	101,684	96,233	-	2,211
	South	189	40,005	39,035	2,211	-

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

The surplus capacity, with reference to PRMR target, offered into the 2026 auction was within the projections range included in the 2025 OMS-MISO Survey



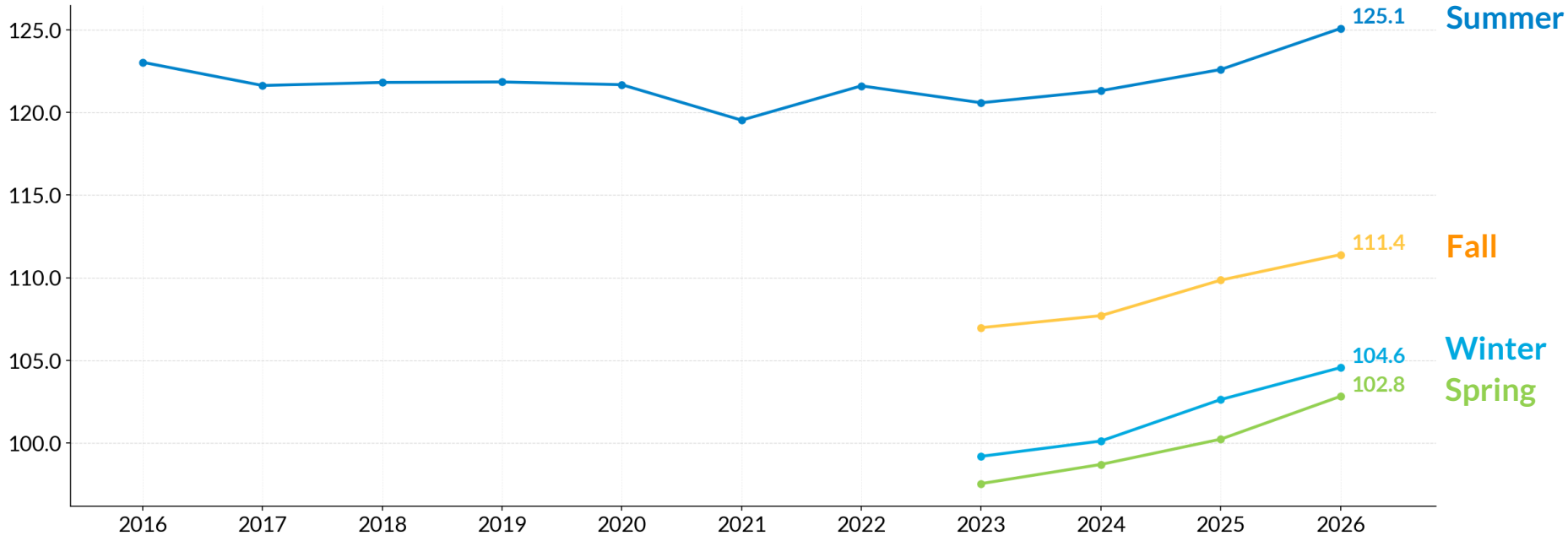
Summer 2026 auction outcomes vs. 2025 OMS-MISO Survey projection for 2026

- Surplus capacity above PRMR target offered into the 2026 PRA for Summer 2026 was ~4.6GW which is within the range of 1.4 GW – 6.1 GW projections in the 2025 OMS-MISO Survey
- Incremental accreditation reductions in the auction were offset by incremental increases in new resource additions
- Notably, initial PRMR was lower (0.6 GW) than projected in the OMS-MISO Survey

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

Coincident Peak Forecast History

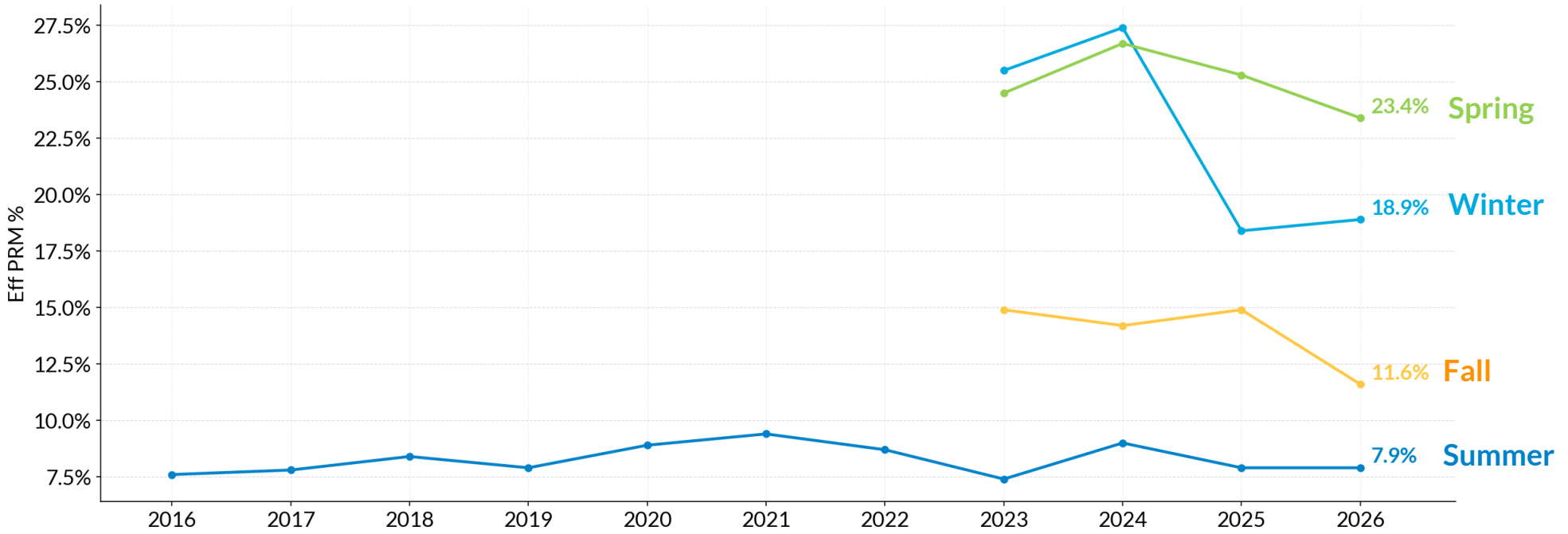
Year-over-year:
- Summer CPF (+2.5 GW)
- PRM (+/-0.0%)
- Final PRMR (+4.8 GW)



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Summer CPF	123,035.8	121,631.2	121,815.6	121,845.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6	125,080.2
Fall CPF								106,973.8	107,701.4	109,850.0	111,392.9
Winter CPF								99,188.0	100,114.6	102,624.0	104,556.9
Spring CPF								97,537.6	98,697.8	100,225.2	102,818.0

CPF: Coincident Peak Forecast

Planning Reserve Margin History

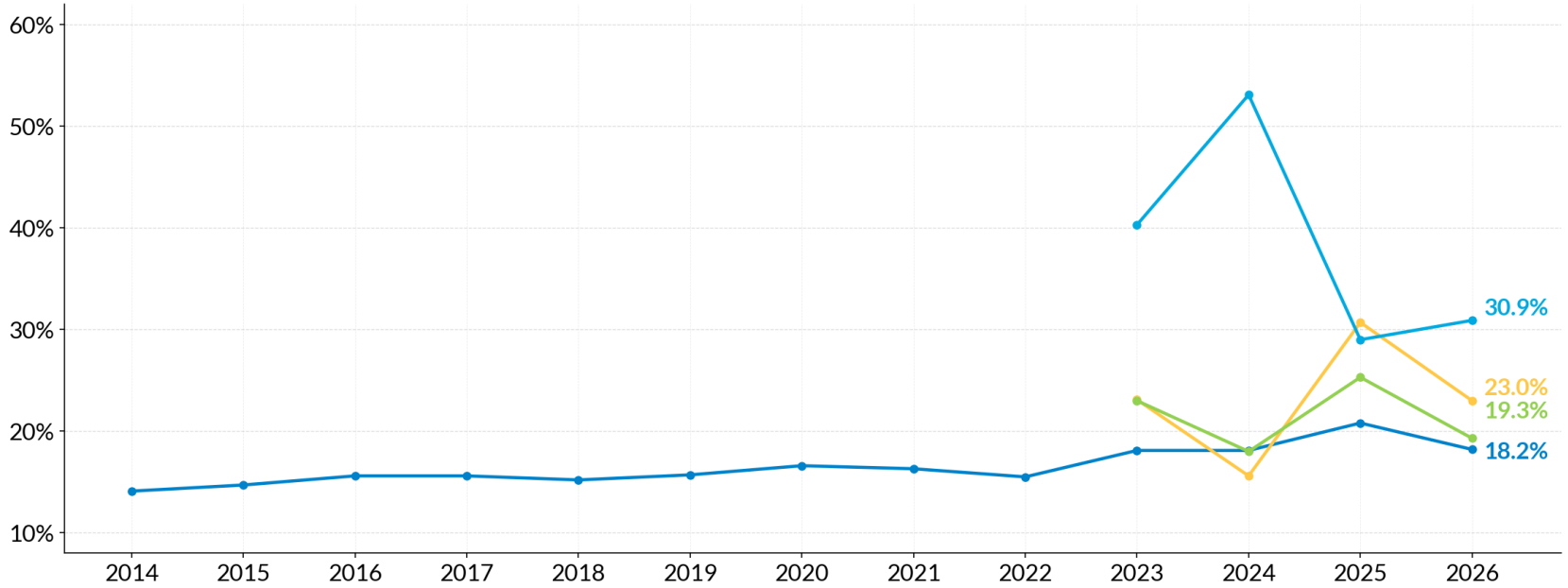


	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Summer PRM	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%	7.9%
Fall PRM								14.9%	14.2%	14.9%	11.6%
Winter PRM								25.5%	27.4%	18.4%	18.9%
Spring PRM								24.5%	26.7%	25.3%	23.4%

PRM: Planning Reserve Margin

Wind Effective Load Carrying Capacity (%)

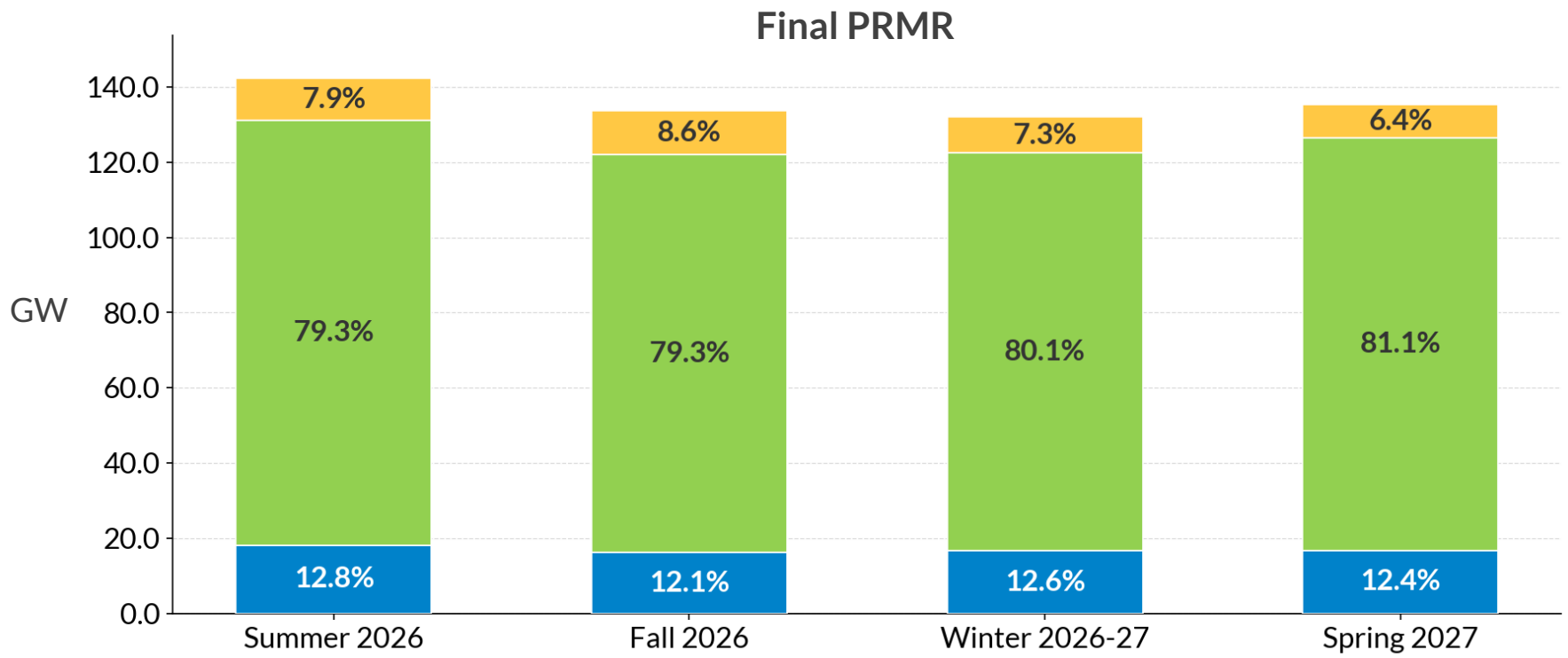
- No change to wind or solar accreditation methodology from previous years
- Methodology applied on a seasonal basis
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar class average
  - Summer, Fall, Spring: 50%; Winter: 5%



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Summer ELCC	14.1%	14.7%	15.6%	15.6%	15.2%	15.7%	16.6%	16.3%	15.5%	18.1%	18.1%	20.8%	18.2%
Fall ELCC										23.1%	15.6%	30.7%	23.0%
Winter ELCC										40.3%	53.1%	29.0%	30.9%
Spring ELCC										23.0%	18.0%	25.3%	19.3%

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

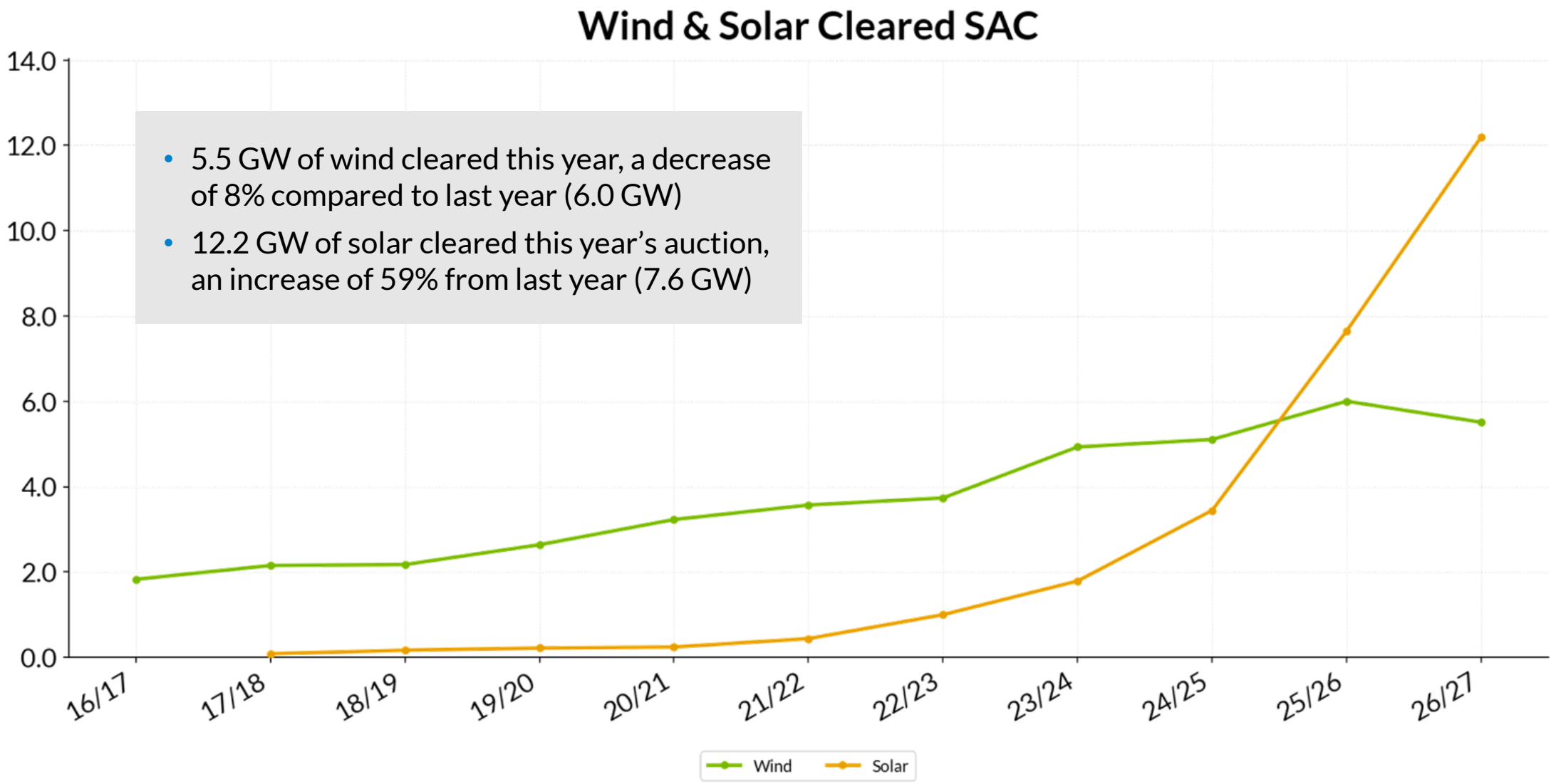
2026/27 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons



	Summer 2026	Fall 2026	Winter 2026-27	Spring 2027
Cleared Non-Self Scheduled	11,305.4	11,506.8	9,582.2	8,706.9
Self Scheduled	112,880.8	105,957.6	105,773.5	109,740.8
FRAP	18,188.1	16,164.4	16,626.8	16,819.4

PRMR: Planning Reserve Margin Requirement FRAP: Fixed Resource Adequacy Plan

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

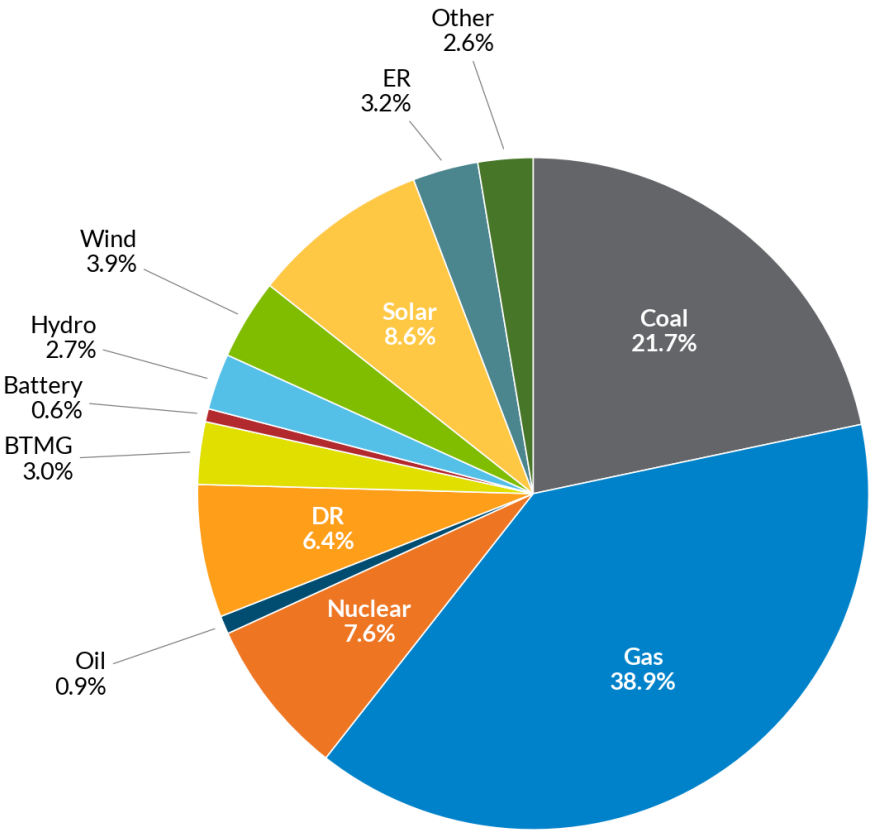


- 5.5 GW of wind cleared this year, a decrease of 8% compared to last year (6.0 GW)
- 12.2 GW of solar cleared this year's auction, an increase of 59% from last year (7.6 GW)

SAC: Seasonal Accredited Capacity

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

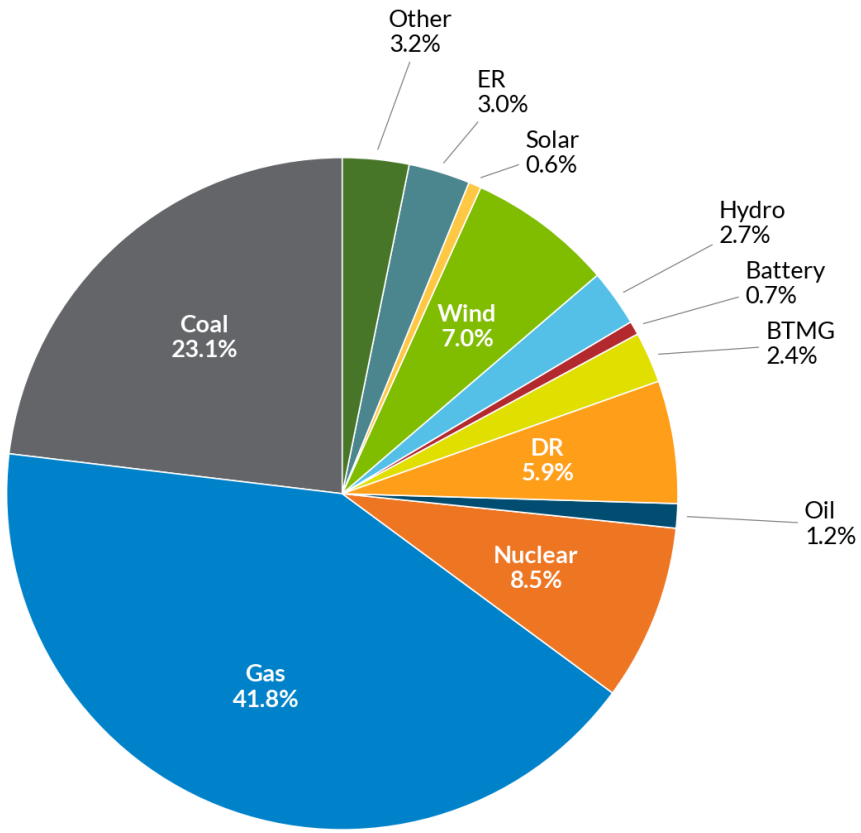
Summer 2026



MISO-Wide

Cleared ZRC	Summer 2026	Winter 2026/27	Difference
Coal	30,884.7	30,492.7	392.0
Gas	55,391.4	55,158.7	232.7
Nuclear	10,782.8	11,167.2	-384.4
Oil	1,246.5	1,548.8	-302.3
DR	9,099.5	7,789.6	1,309.9
BTMG	4,272.9	3,228.3	1,044.6
Battery	893.8	870.4	23.4
Hydro	3,843.1	3,595.9	247.2
Wind	5,509.1	9,196.2	-3,687.1
Solar	12,198.3	801.9	11,396.4
ER	4,490.6	3,911.0	579.6
Other	3,761.6	4,221.8	-460.2
PRMR	**142,374.3**	**131,982.5**	**10,391.8**

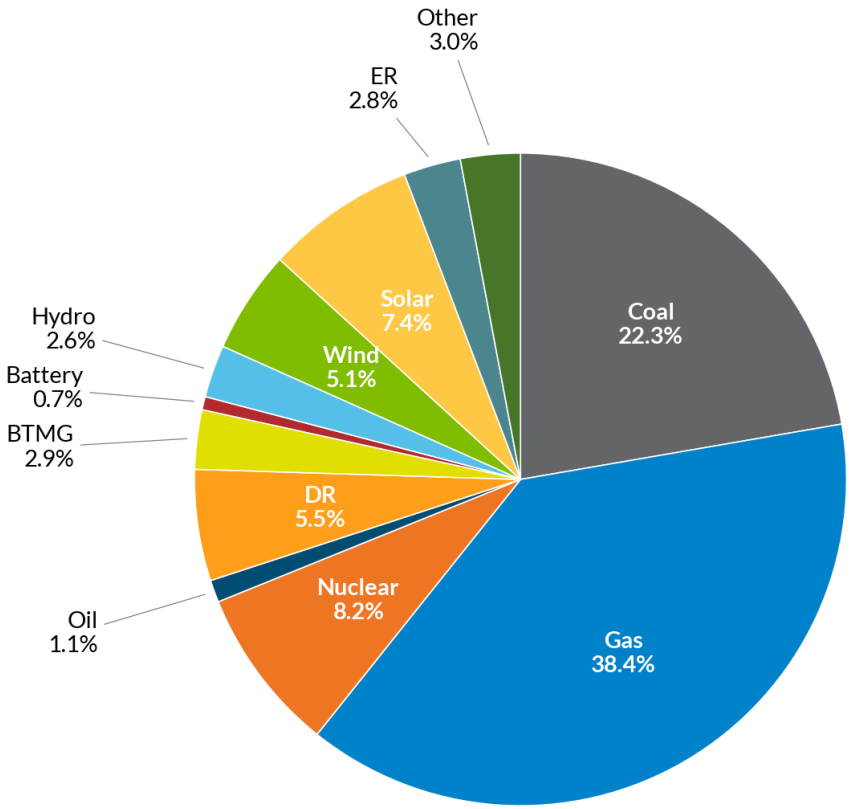
Winter 2026/27



PRMR: Planning Reserve Margin Requirement

Fall 2026 and Spring 2027 - Cleared ZRCs and Final PRMR

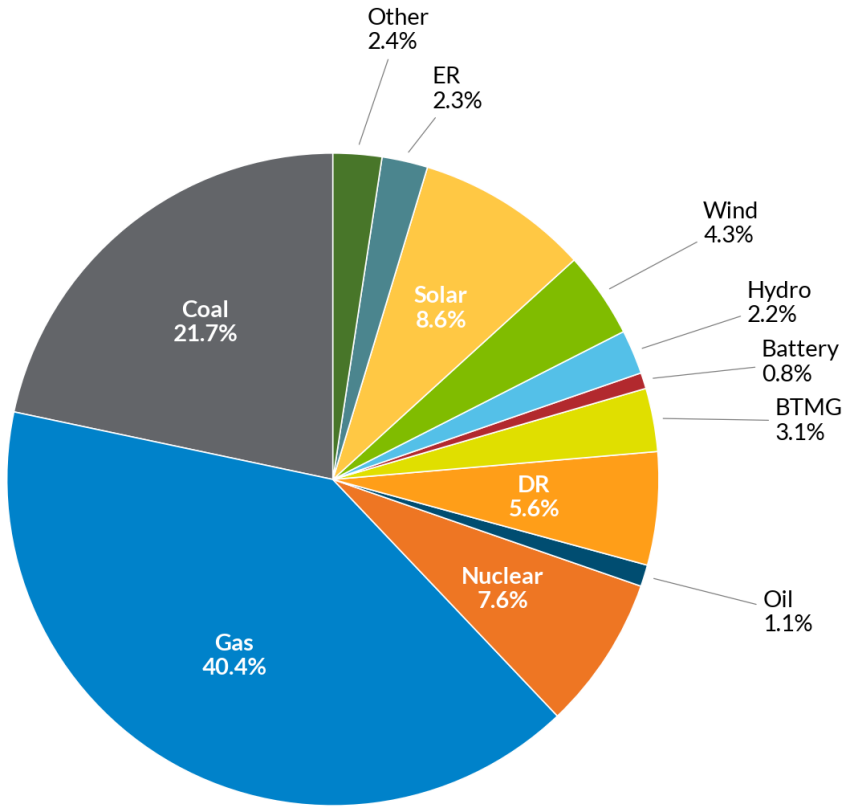
Fall 2026



MISO-Wide

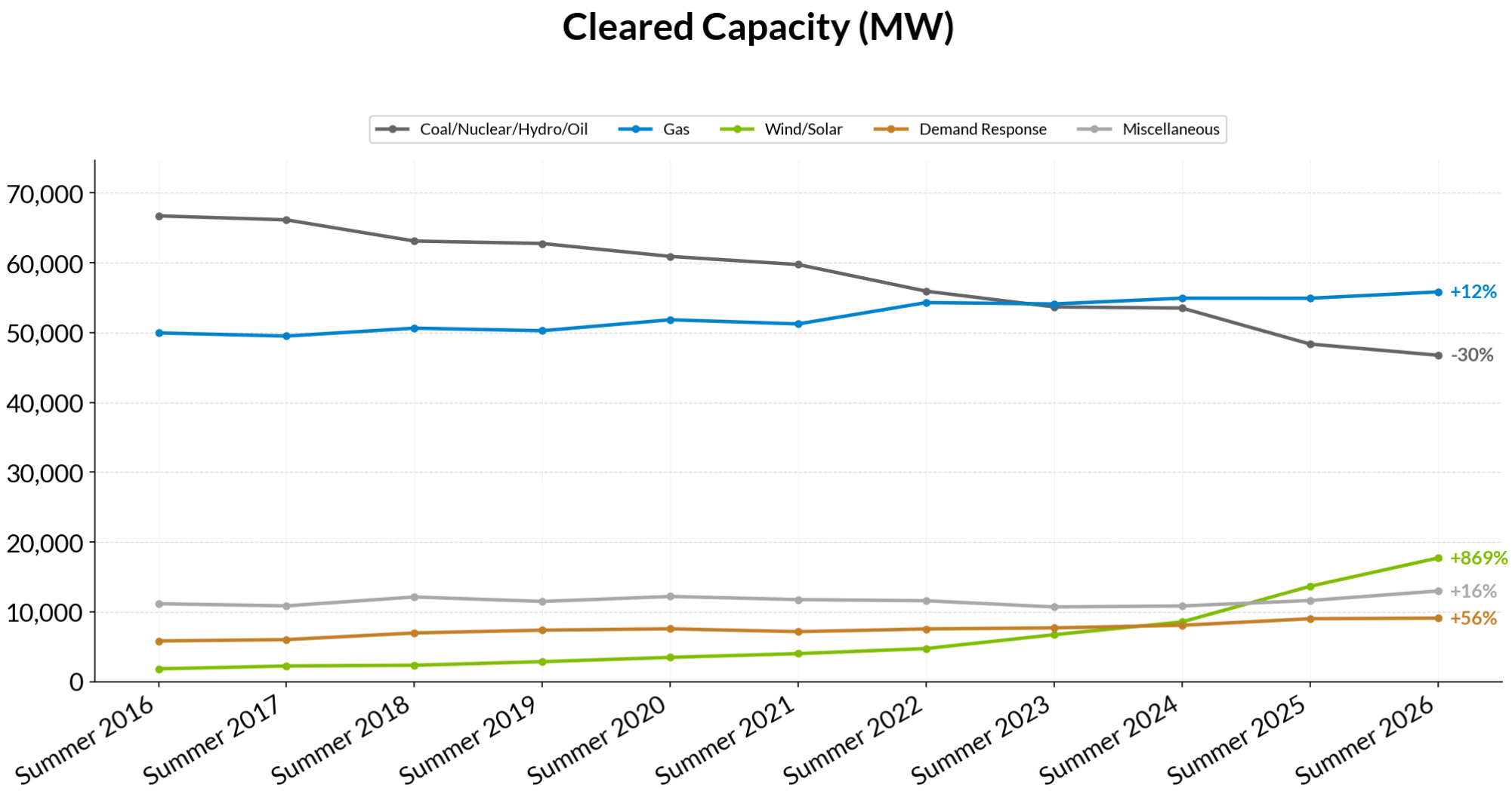
Cleared ZRC	Fall 2026	Spring 2027	Difference
Coal	29,777.7	29,324.7	453.0
Gas	51,370.6	54,663.4	-3,292.8
Nuclear	10,900.3	10,286.7	613.6
Oil	1,471.9	1,448.6	23.3
DR	7,364.4	7,576.5	-212.1
BTMG	3,923.0	4,240.2	-317.2
Battery	873.3	1,070.8	-197.5
Hydro	3,475.3	2,964.0	511.3
Wind	6,797.3	5,757.1	1,040.2
Solar	9,932.9	11,595.0	-1,662.1
ER	3,780.2	3,076.5	703.7
Other	3,961.9	3,263.6	698.3
PRMR	**133,628.8**	**135,267.1**	**-1,638.3**

Spring 2027

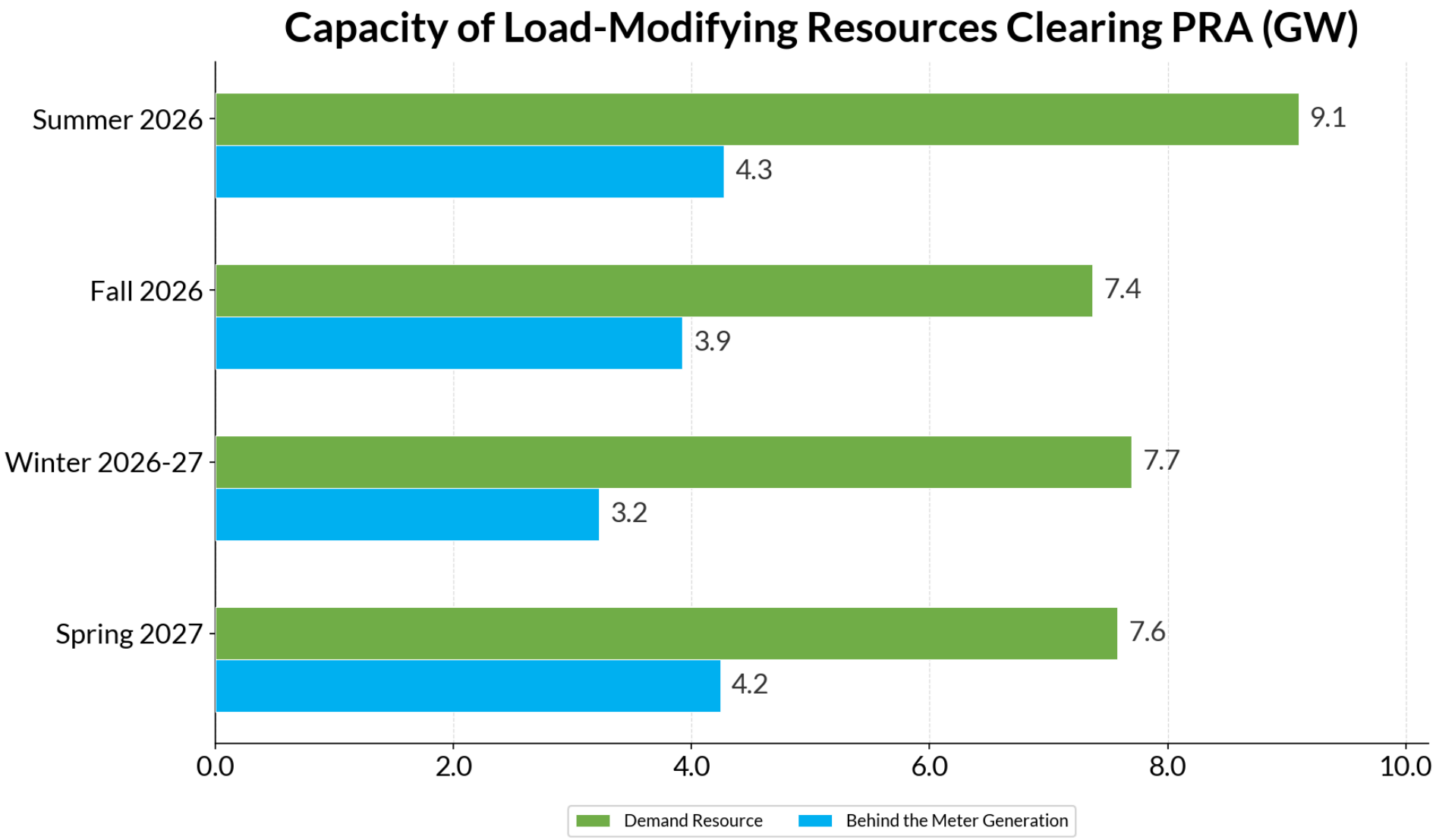


PRMR: Planning Reserve Margin Requirement ZRC: Zonal Resource Credit

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



2026/27 Seasonally Cleared Load Modifying Resources Comparison



PRA: Planning Resource Auction

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

MISO

Seasonal Readiness Workshop: Summer 2026

May 6, 2026

Agenda

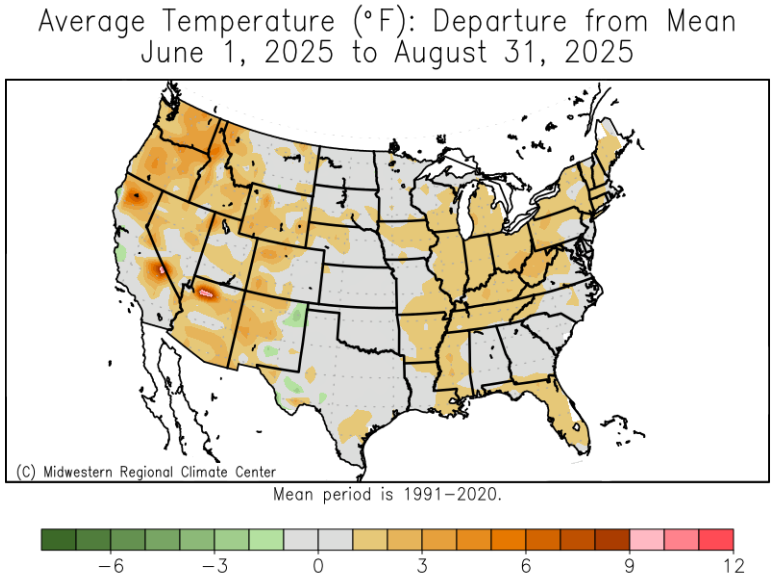
1. **Welcome** – JT Smith, Executive Director, MISO System Operations
2. **Seasonal Assessments**
   - Weather – Adam Simkowski/Ella Dankanics, MISO Meteorologists
   - Generation – Andy Taylor, Manager, MISO Resource Adequacy
   - Transmission – Fisseha Zewdu, Sr. Engineer, MISO Operations Planning
3. **Seasonal Risk / Uncertainty Management** – Matt Campbell, Manager, Operations Risk Assessment
4. **Emergency Procedure & Technical Training Updates**
   - Capacity Emergency Changes – Don Hunter, Manager, MISO Control Room Operations
   - 202(c) Emergency Orders – Don Hunter, Manager, MISO Control Room Operations
   - Transmission System Emergency Procedure Updates– Clayton Umlor, Manager, MISO Reliability Coordination
   - Technical Development – Anita Hurst, Sr. Manager, MISO Technical Development
5. **Q&A**

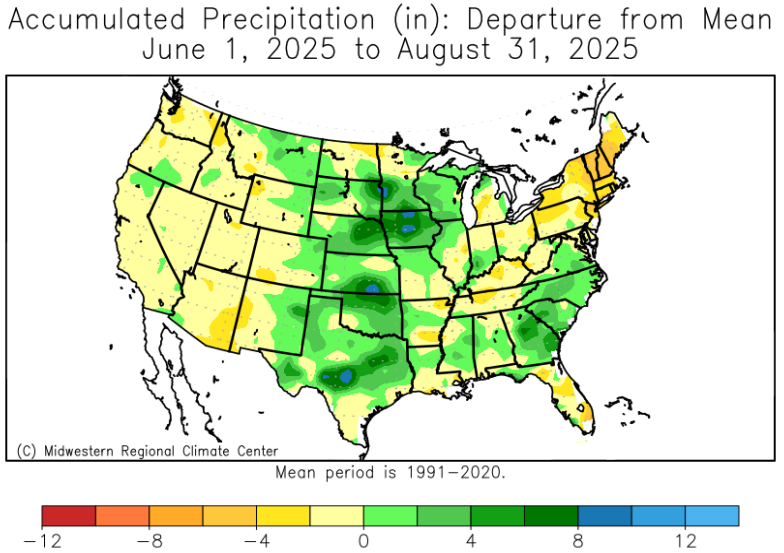
Seasonal Assessment: Weather

Adam Simkowski and Ella Dankanics, MISO Meteorologists

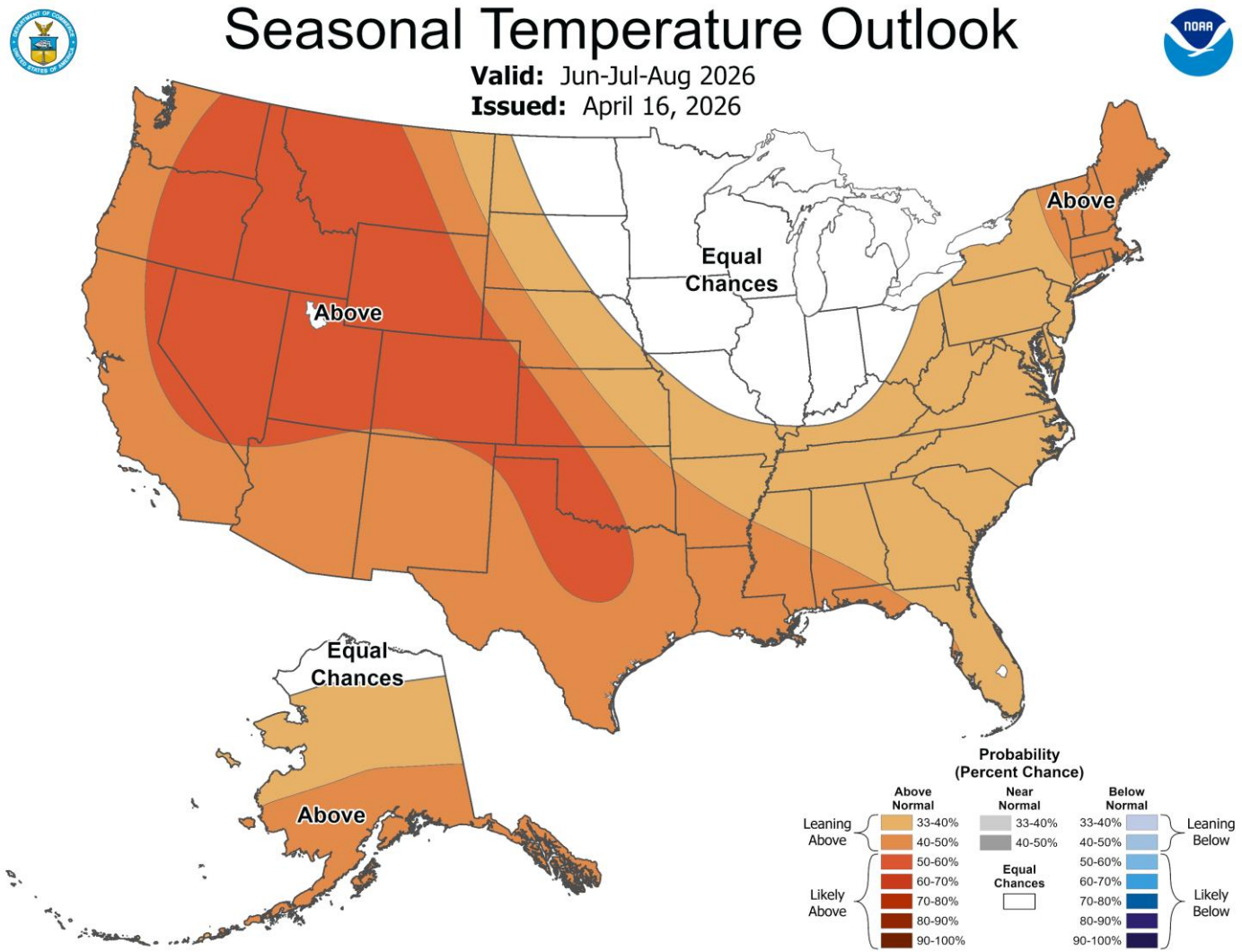
Despite Above Normal Precipitation, La Niña Drove Above Normal Temperatures Across MISO's Footprint

- Last summer, we experienced:
- Above normal temperatures across the North/Central Region
- Slightly above normal temperatures in the South Region
- There were 6 days recorded above 90°F Systemwide temperature
- Near to slightly above normal precipitation was observed across much of the MISO footprint

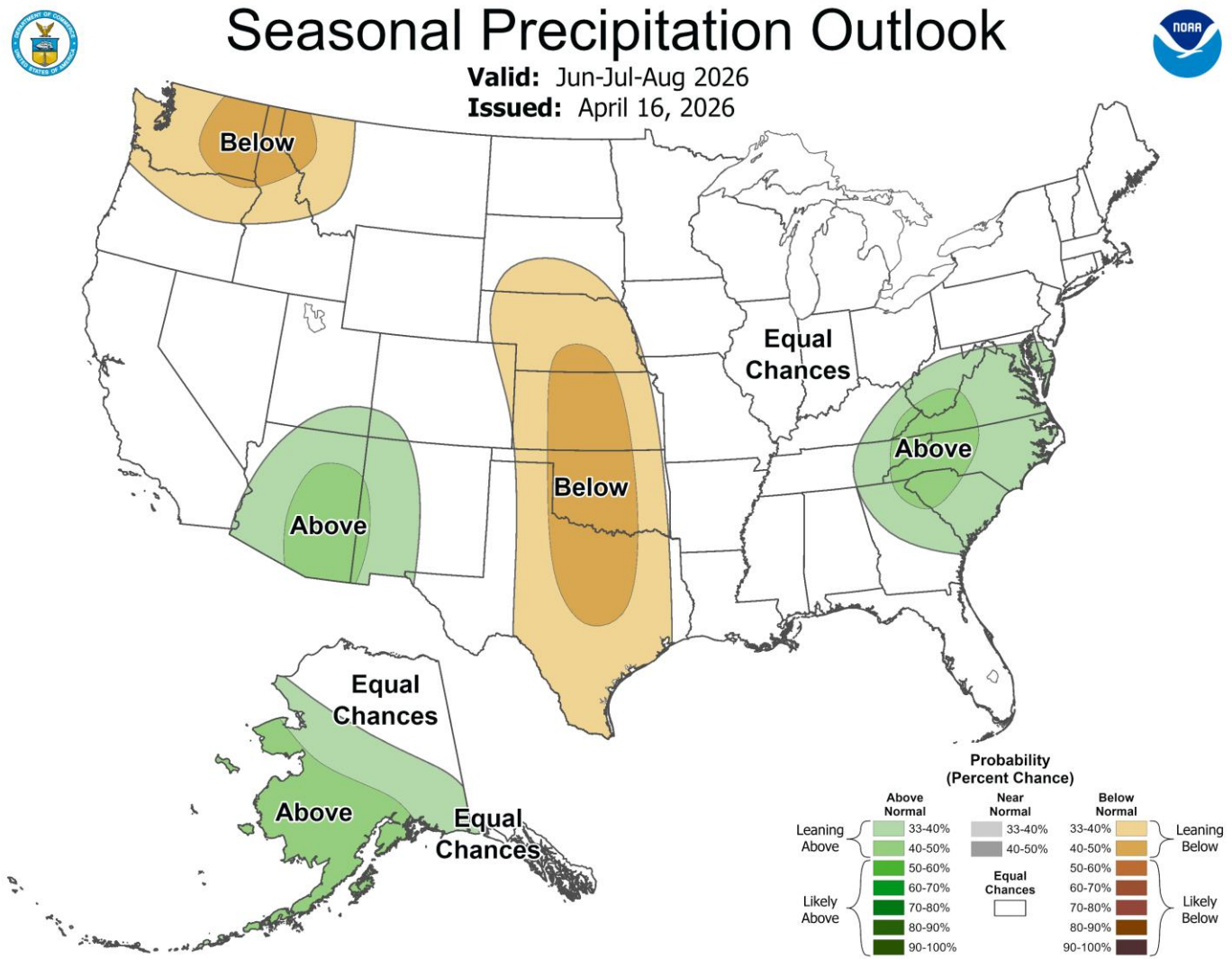




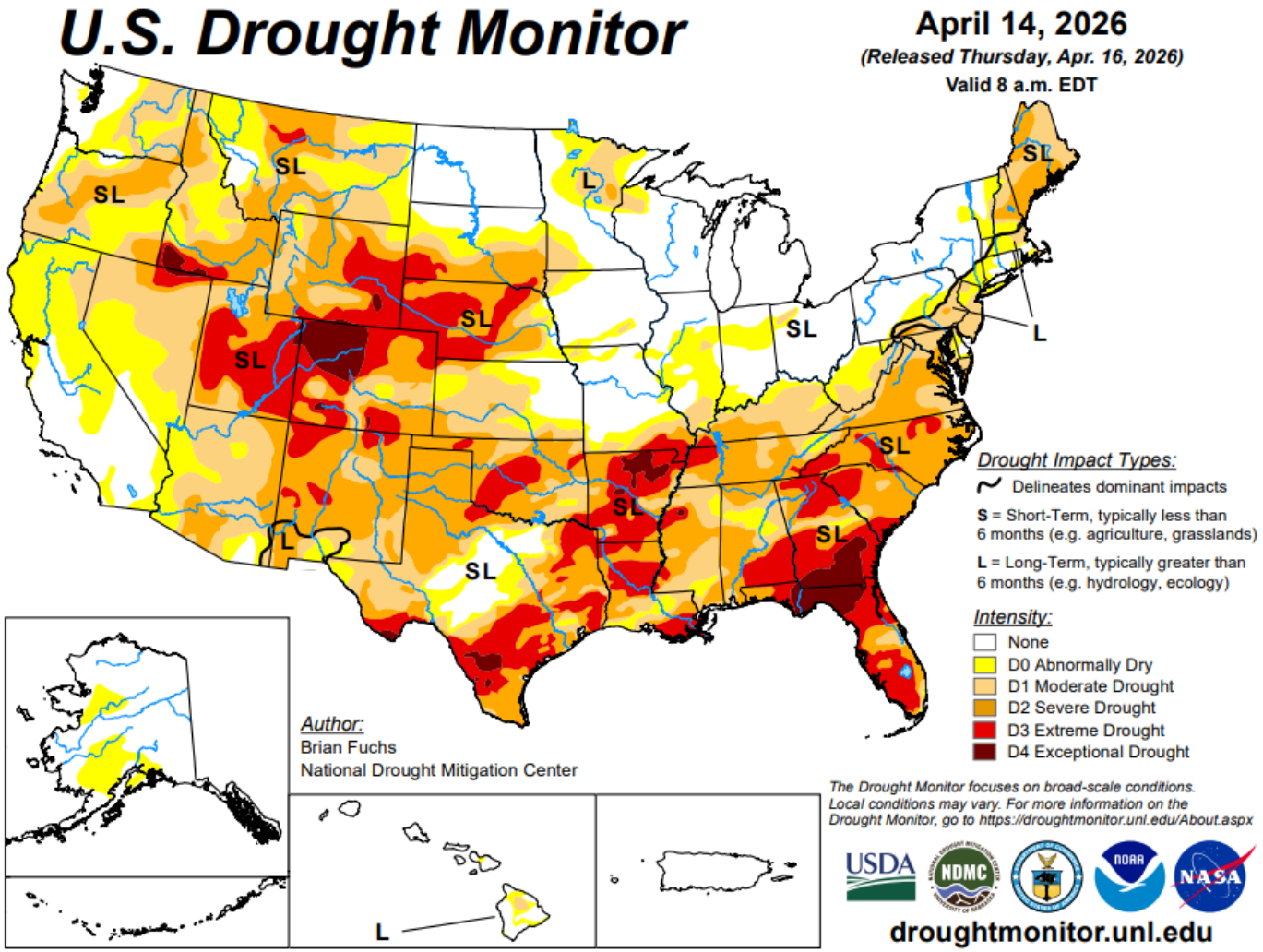
NOAA is forecasting above normal temperatures for June through August in MISO's South Region with near normal temperatures across MISO's North/Central Region holding the core of the heat in the intermountain West



NOAA anticipates normal precipitation rates across the majority of MISO's footprint



US drought conditions will need to be monitored as pervasive drought can exacerbate heat concerns over MISO footprint



Circled years are the best historical analog (reference) years to this upcoming summer

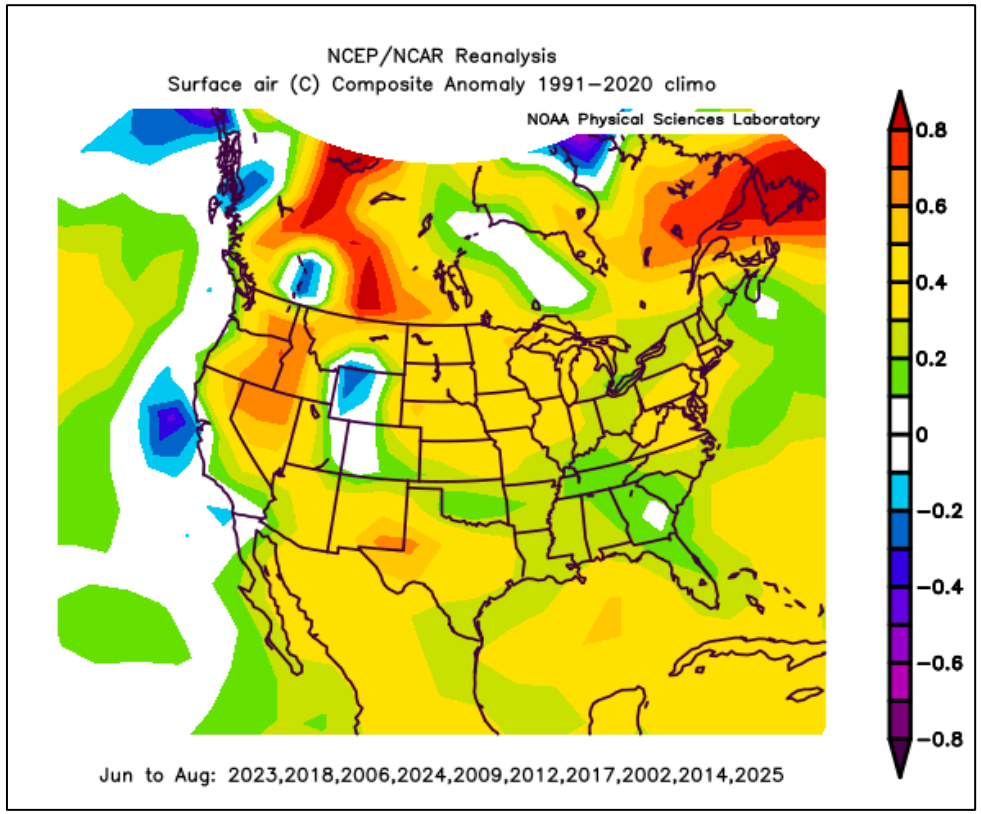
Analog years for Summer 2026

Year(s)	Vendor A	Vendor A Rank	Vendor B	Vendor B Rank
	2023	1	2015	1
	2018	2	2023	2
	2006	3	2009	3
	2024	4	1951	4
	2009	5	1997	5
	2012	6	2006	6
	2017	7	2002	7
	2002	8	1963	8
	2014	9	2012	9
	2025	10	1991	10

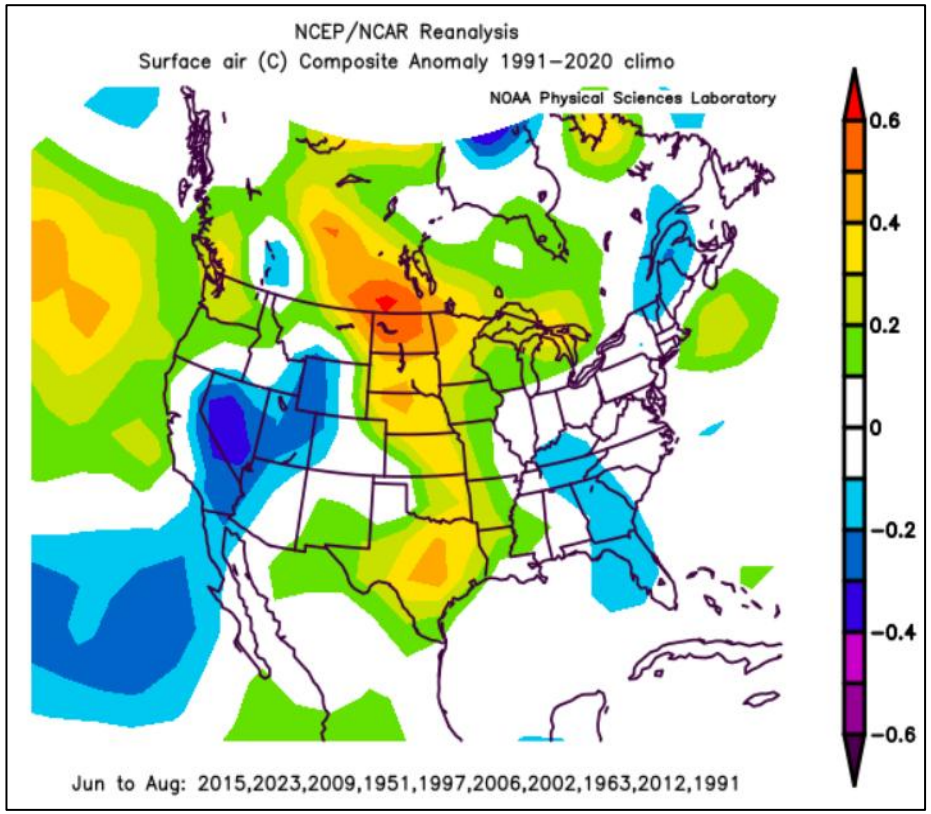
Cool MISO Summer
Warm MISO Summer
Normal MISO Summer

While both vendors' analog year selections favor heat across MISO's footprint, their selections were created in late winter with more El Niño uncertainty. With high certainty of El Niño now, top analog years are under-weighted in the images below.

Vendor A

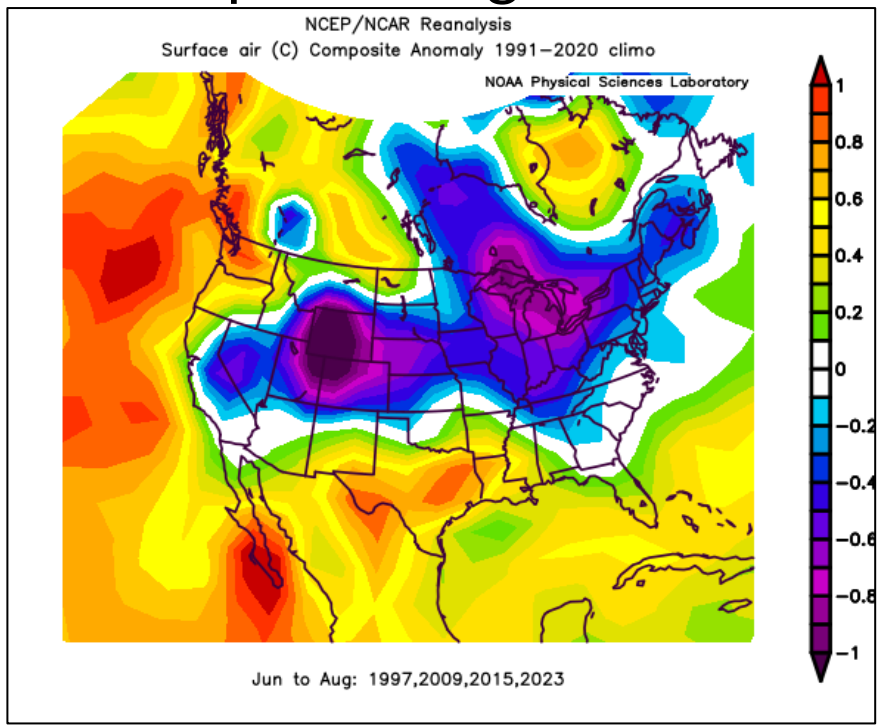


Vendor B



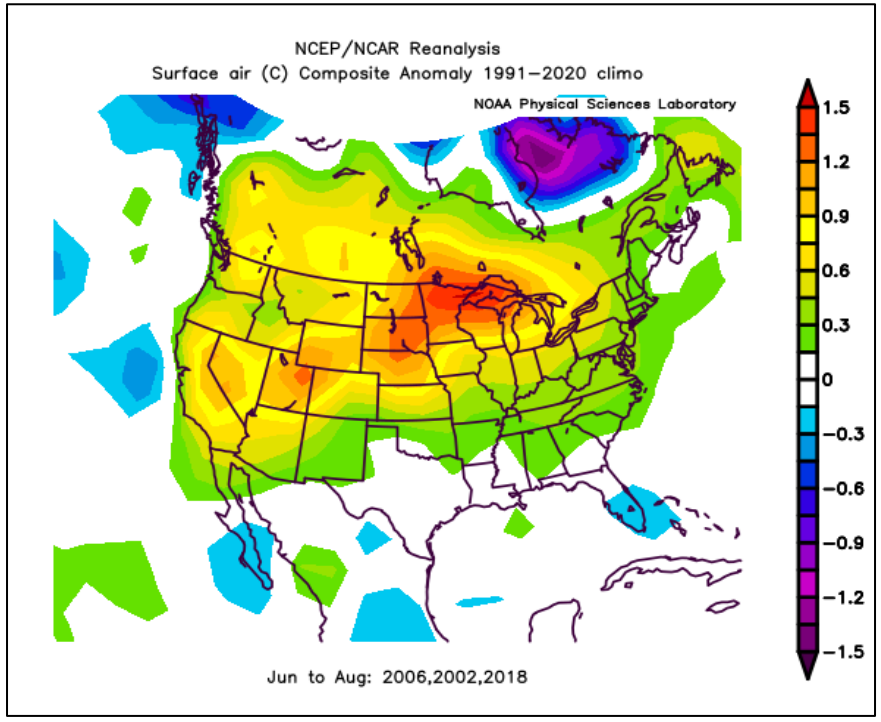
MISO's analysis of historical analog years from each vendor support a cooler to average summer for MISO's North/Central Region, but there is a higher likelihood for above normal temperatures in MISO's South Region

Top 4 Analog Years



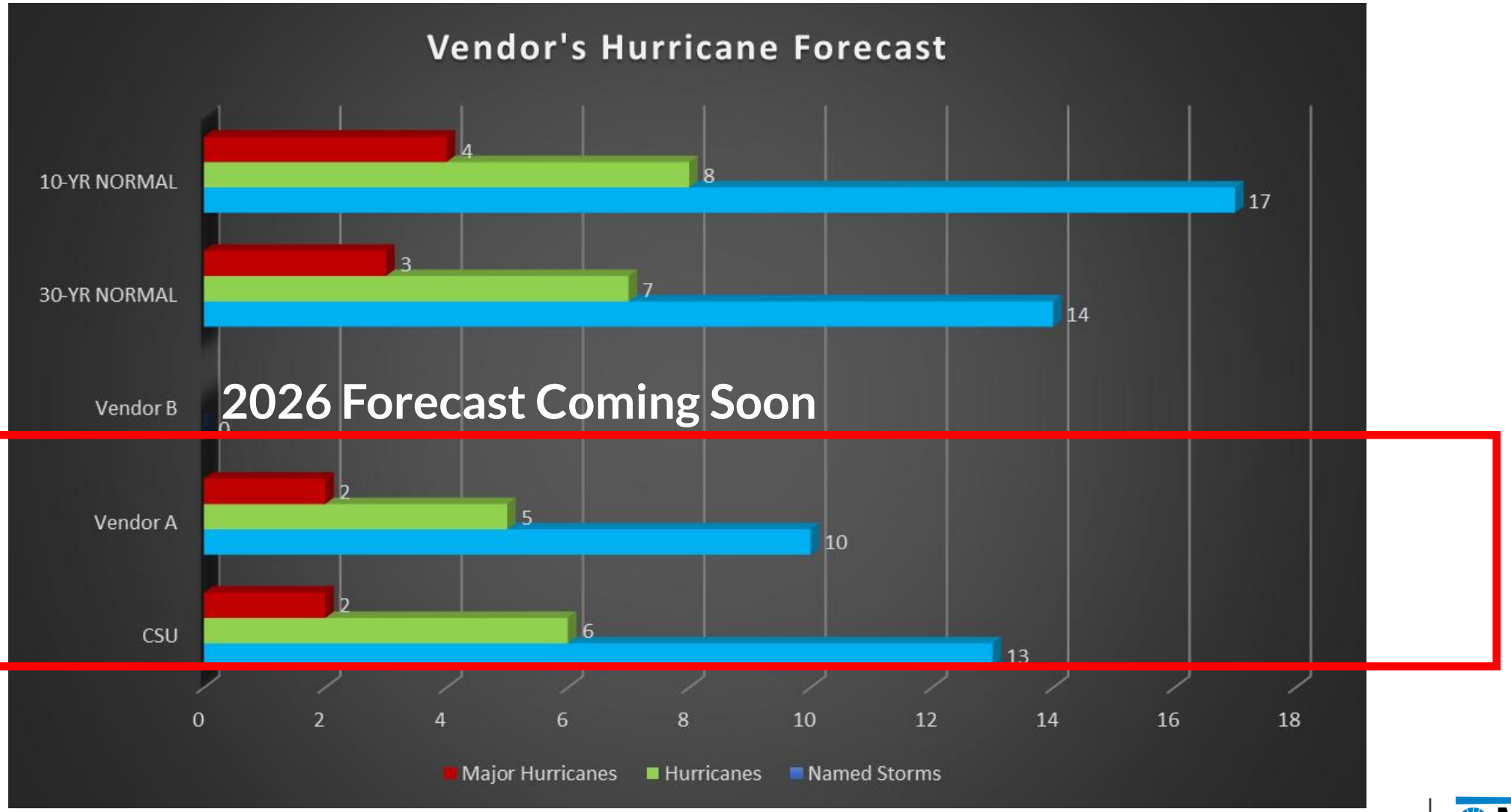
- More likely scenario
- Good agreement with vendors forecast on TX/LA heat

Top 3 Warm Analog Years

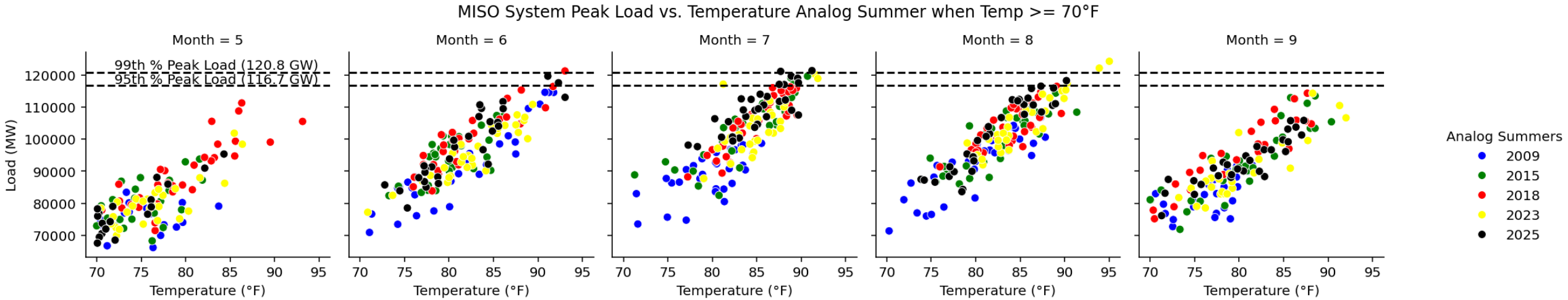


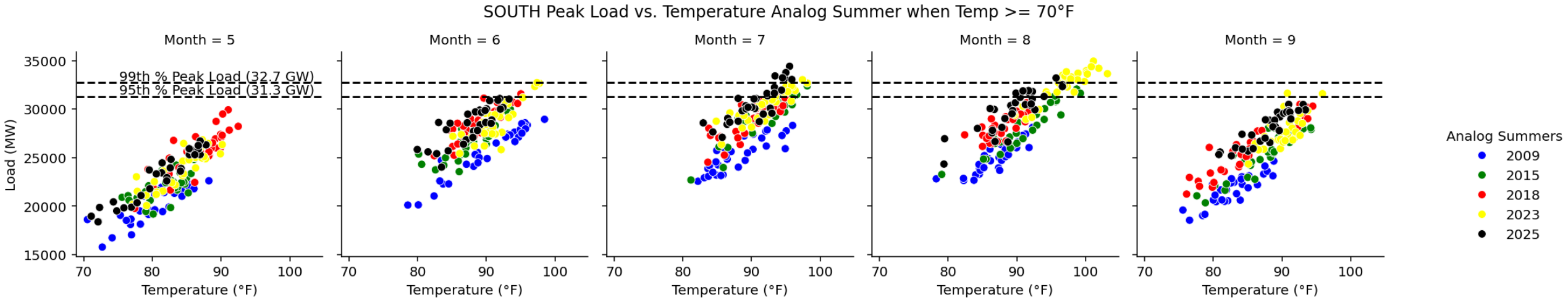
- Less likely scenario
- Heat extends from the intermountain west to MISO North/Central Region

A slightly below normal hurricane season is expected from all vendors; threats to MISO are best evaluated in a two-week forecast window



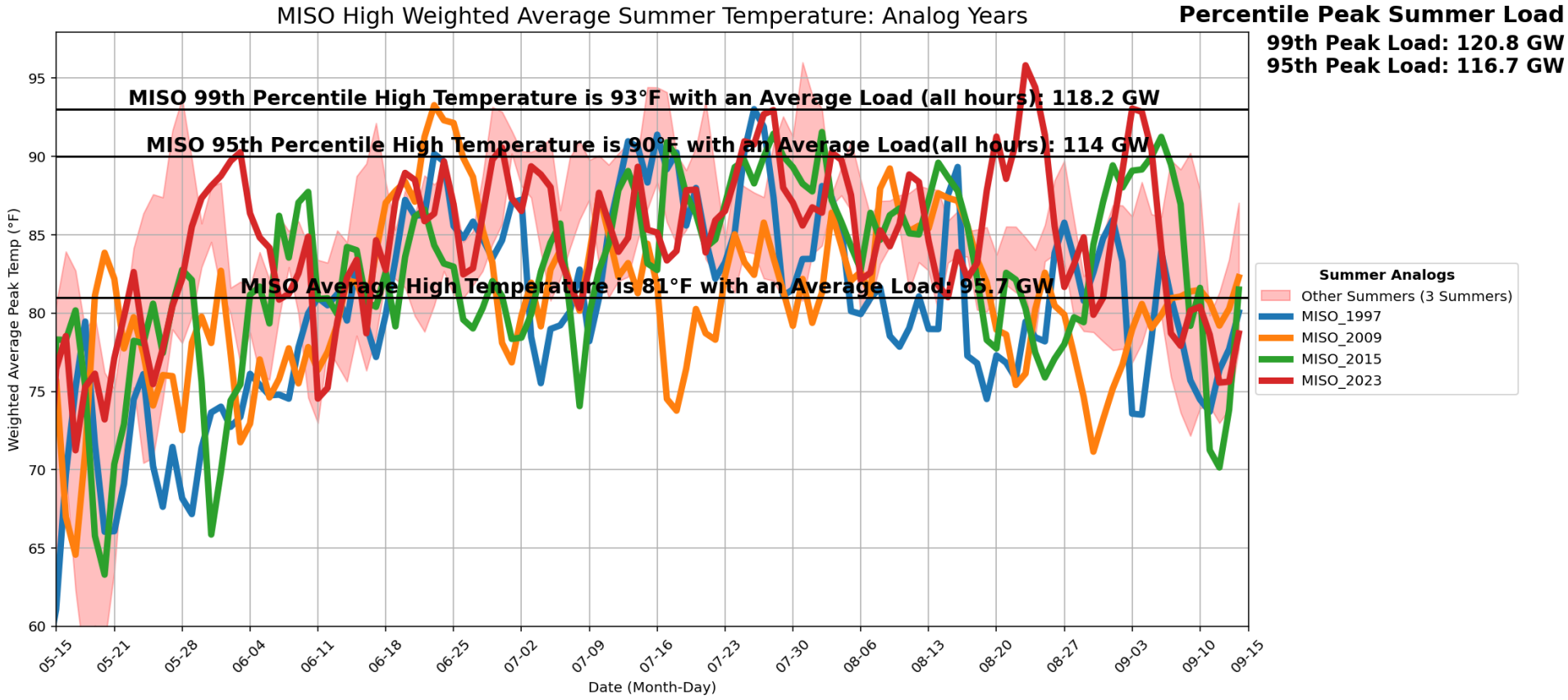
Systemwide, comparing top analog years to last year and lower match 2018, top analog years contain minimal hours reaching 99th percentile peak load. TX/LA heat did bring South load at/above 99th percentile in top years



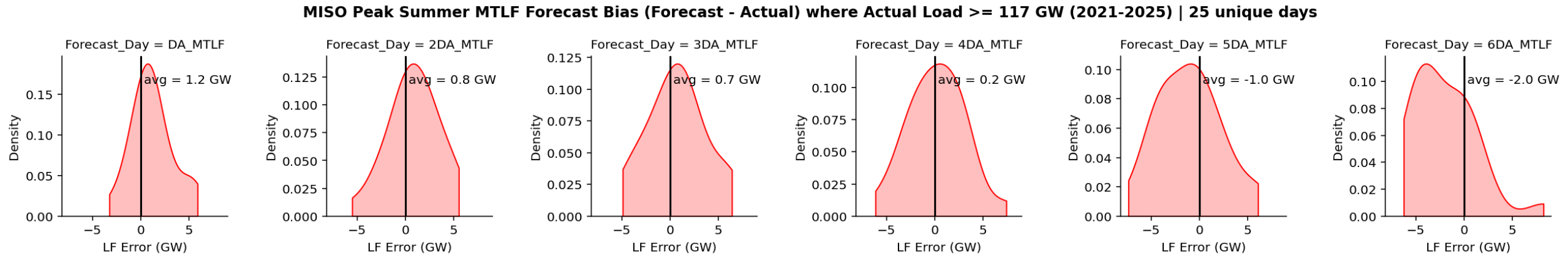


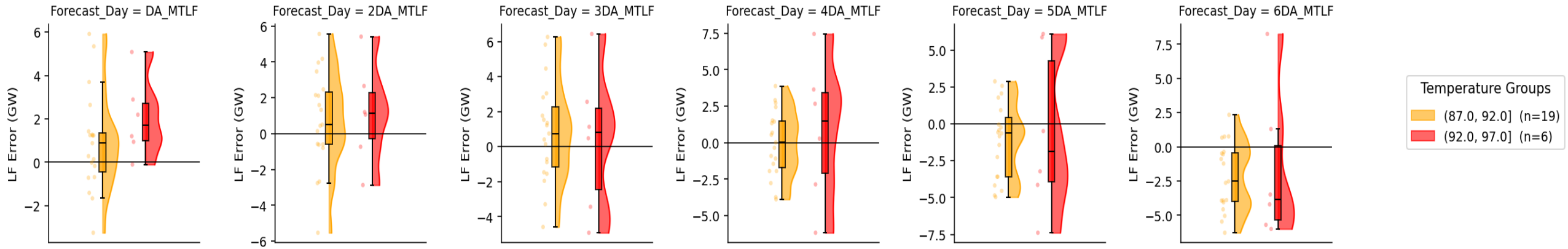
Key analog summers saw daily peak temperatures above the 95th percentile high temperature threshold, but few periods at 99th percentile high temperature threshold

The top analog year (2023) had major MISO heatwave reaching above the 99th percentile average load threshold driven by TX/LA heat dome



Summer peak load forecast bias is positive at DA and 2-DA primarily due to storm risks where peak load >= 95th percentile (117 GW)





Adam and Ella's Opinion

- While normal to below normal summer is expected in the North/Central, heat waves will be more likely and confined to the South region, especially if drought conditions persist.
- 2023 being the top analog had a similar orientation to this year's expectations. In August of that year, the South heat dome expanded north encompassing MISO's footprint producing our all-time peak load (not reconstituted). We'll monitor that risk closely this summer with El Niño strength.
- Solar growth will continue throughout the summer. Wind generation is forecast to be **below normal** and risks around the **daily cycle** (AM ramp down, PM ramp up) with ample solar will produce challenging Net Load ramps.
- With warm ocean waters over the Caribbean and Gulf, risks for 'homegrown' storms will have to be monitored closely despite a projected below normal season.

Summary

- A normal to slightly below normal summer is expected in the North/Central region with above normal temperatures in MISO South.
- Despite cooler signals for the Midwest and Plains, with heat more likely in the southern Plains and Gulf Coast, heat can expand northward periodically.
- Monitoring the development and strength of El Niño will provide confidence on both the cooler North/Central signal and lower tropical development potential.
- A near to slightly-below-normal hurricane season is expected in the Atlantic Basin this hurricane season.

Contact: Adam Simkowski, asimkowski@misoenergy.org
Ella Dankanics, edankanics@misoenergy.org

Seasonal Assessment: Generation

Andy Taylor, Manager, MISO Resource Adequacy

Seasonal Capacity Outlook – Summer 2026

LRZ	Price ($/MW-Day)
1-7	$424.30
8,10	$384.10
9	$412.10

Initial PRMR	ZRC Offered + FRAP	Final PRMR
137,922.8	142,553.1	142,374.3

- Implementation of the Reliability-Based Demand Curve has resulted in significant value for capacity beyond the 1-in-10 LOLE Requirement.
- Initial PRMR represents the traditional 1-in-10 LOLE Requirement.
- 4,451.5 ZRCs cleared beyond the 1-in-10 LOLE Requirement, resulting in the Final PRMR noted above.

Planning Resource	Offered (ZRC)	Cleared (ZRC)
Generation	124,690.1	124,511.3
External Resources	4,490.6	4,490.6
Behind the Meter Generation	4,272.9	4,272.9
Demand Resources	9,099.5	9,099.5
Energy Efficiency	0.0	0.0
Total	**142,553.1**	**142,374.3**

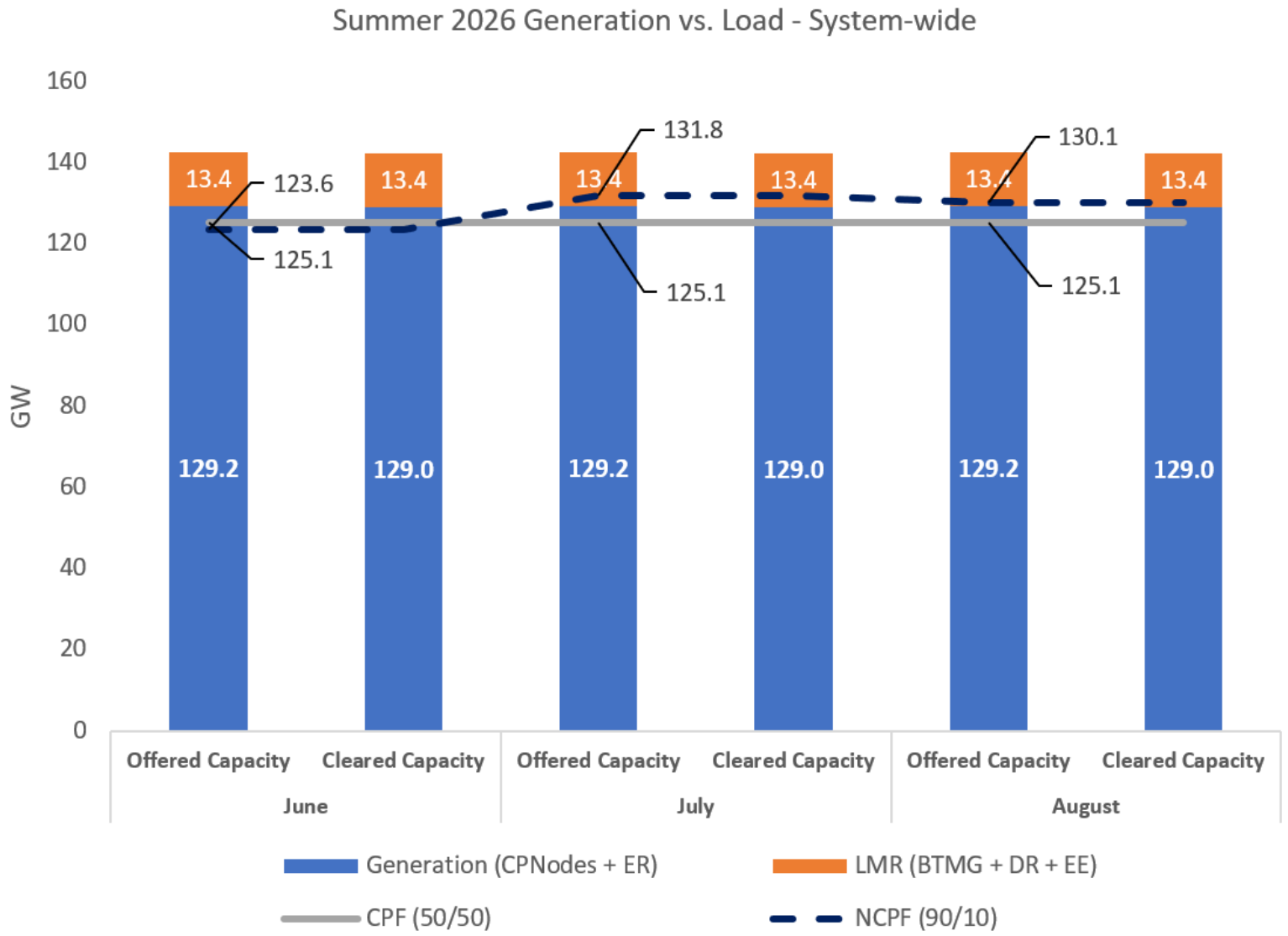
LRZ: Local Resource Zone PRMR: Planning Reserve Margin Requirement ZRC: Zonal Resource Credit FRAP: Fixed Resource Adequacy Plan

RBDC: Reliability-Based Demand Curve LOLE: Loss of Load Expectation

MISO systemwide accredited capacity compared to demand submitted by LSEs

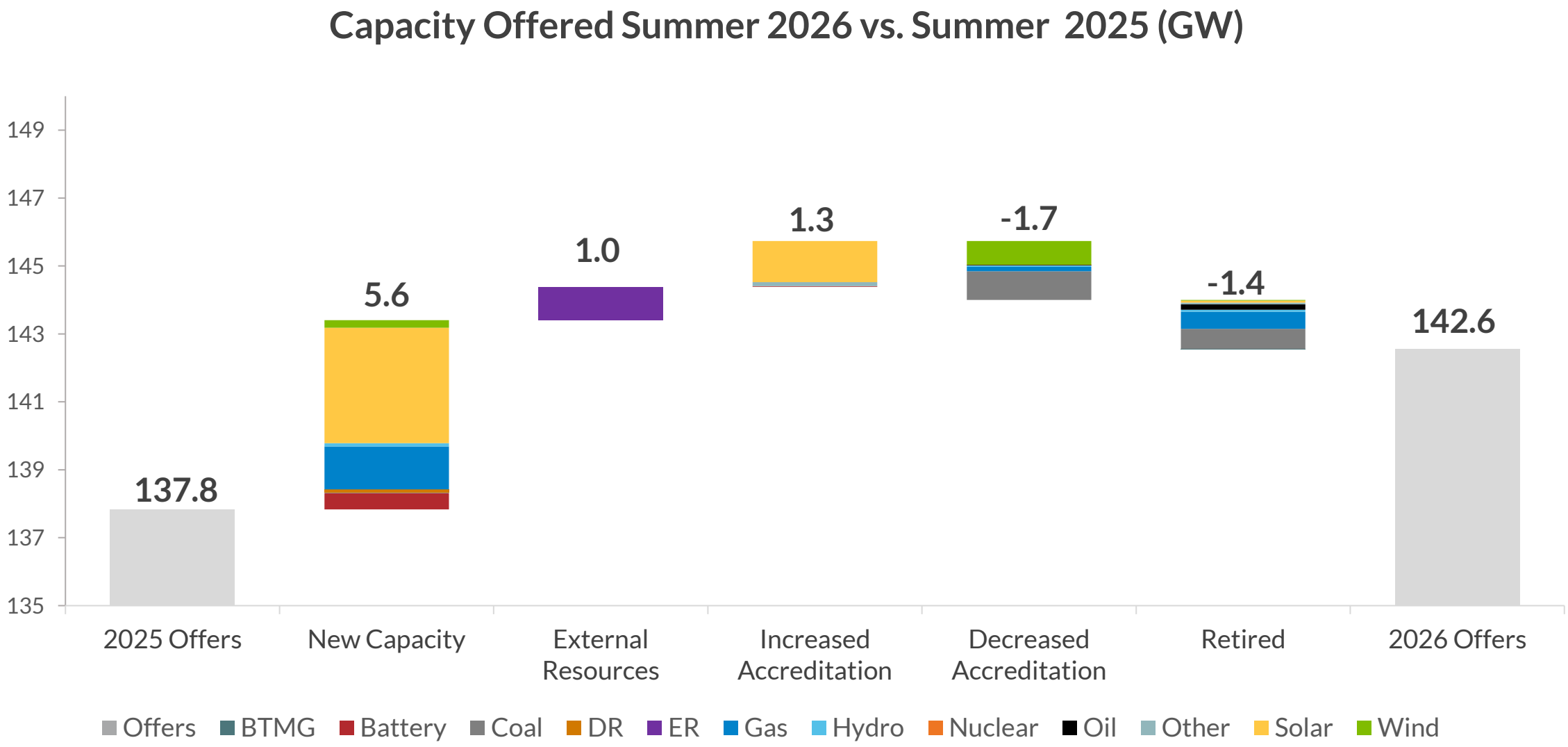
Coincident Peak Forecast is submitted by MISO LSEs relative to the MISO seasonal peak and calculated on a seasonal basis

Non-Coincident Peak Forecast is the peak load submitted by each LSE per month



LMR: Load Modifying Resource CPNodes: Commercial Pricing Nodes ER: External Resource
BTMG: Behind the Meter Generation DR: Demand Resource EE: Energy Efficiency
CPF: Coincident Peak Forecast NCPF: Non-Coincident Peak Forecast

New capacity additions outpaced decreased accreditation and suspensions/retirements



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

Contact: Andy Taylor, ataylor@misoenergy.org

Seasonal Assessment: Transmission

Fisseha Zewdu, Sr. Engineer, MISO Operations Planning FRES

The Coordinated Seasonal Assessment study is used to identify potential issues and develop plans before these issues occur in real time

Purpose:

Evaluate expected conditions across MISO footprint for summer season

Identify potential limitations and issues for upcoming season and develop operating plans

Coordinate with MISO members

Study Focus:

Steady-State Analysis

Bidirectional Transfer Studies

Load Pocket Studies

The 2026 summer model was built from the Eastern Interconnection base case with MISO Transmission projects and planned outages applied

Base Case:

- Built on the 2025/26 Summer ERAG MMWG model
- Generator Retirements approved on or before December 1, 2025, are offline
- Outages: Transmission and Generator Outages are modeled if they are greater than or equal to two months between the months of June through August
- TO's can recommend outages outside the period if deemed necessary

MOD Projects:

- MTEP Appendix A – Planned
- All the generation interconnection projects applied

Generation Assumptions:

- Renewables: Wind and Solar units dispatched at their capacity credit levels
- Qualified Facilities (QFs) and MISO South Load Pocket Op Guides honored

Steady State AC Contingency Analysis did not reveal any contingencies without operating plans for the summer season

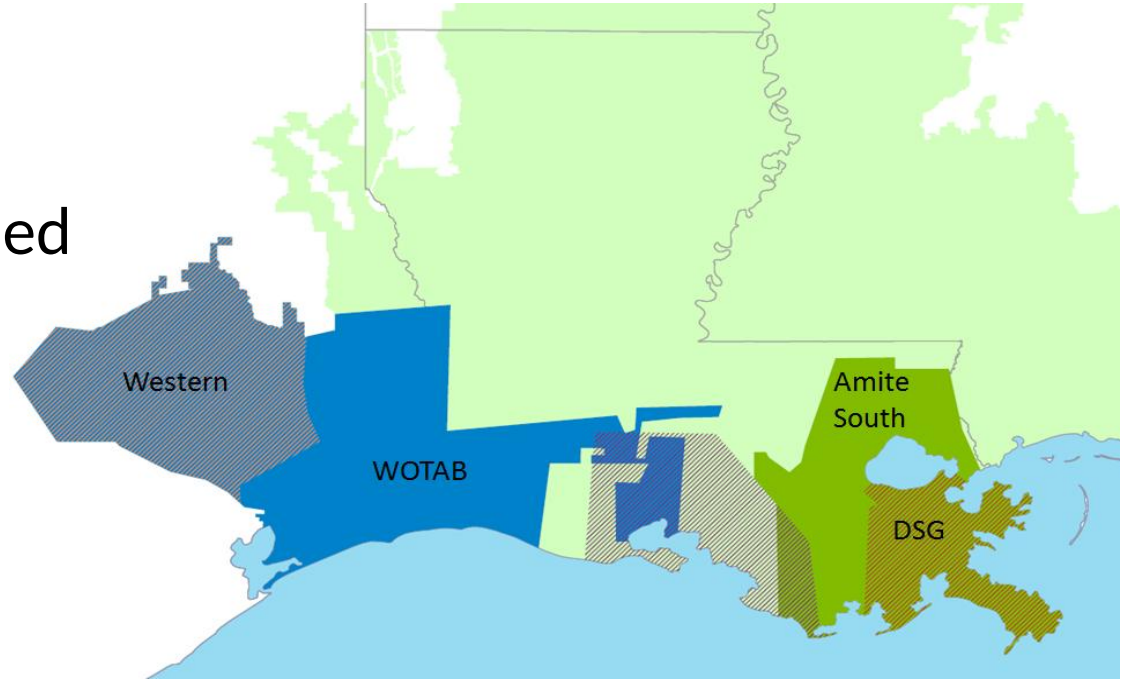
Approximately 18,900+ contingencies were studied

NERC defined Category P1 contingencies

- **P1.1** – three phase faulted generator (>50 MW)
- **P1.2** – three phase faulted transmission circuit
- **P1.3** – three phase faulted transformer
- **P1.4** – three phase faulted shunt device
- **P1.5** – single line to ground dc pole

MISO regularly runs import studies for the Load Pockets

- The peak load conditions for the three MISO load pockets are simulated:
  - Amite South at 7,592 MWs
  - Down stream of Gypsy (DSG) at 3,247 MWs
  - Western at 2,735 MWs
- Transfer studies into the pockets are performed
- Results are used to identify import limits for the pockets



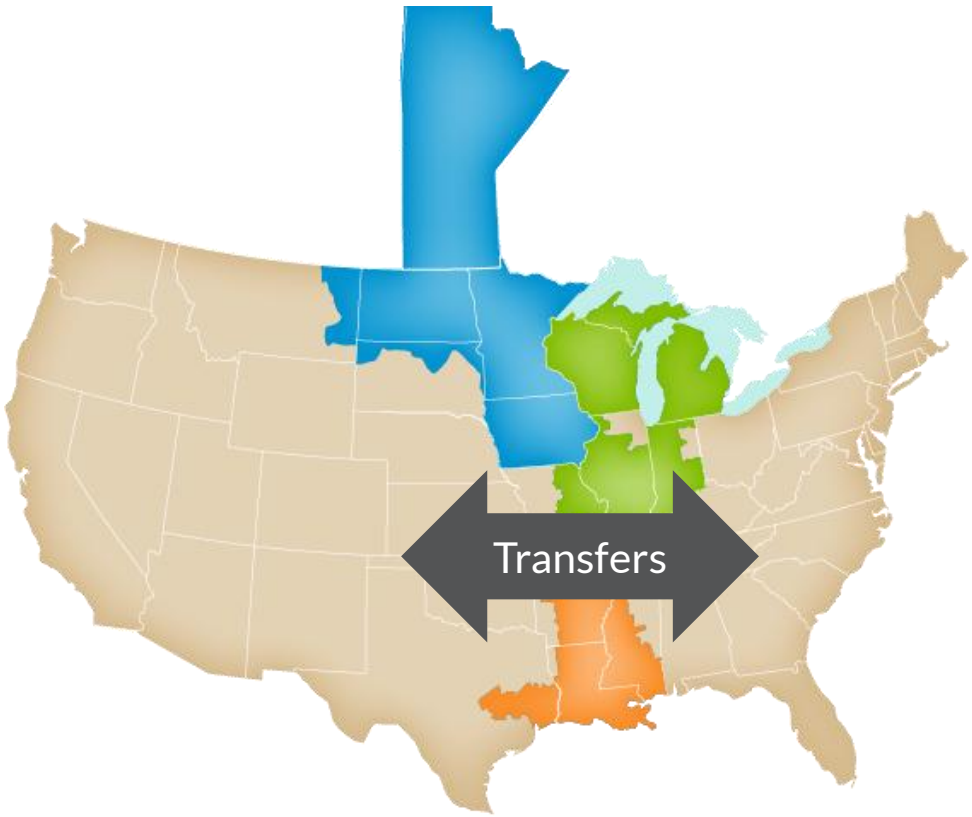
Load Pocket transfer results indicate that import limits are in line with current operating guides

Load Pocket	Monitored Element	Limiting Contingency	Violation Type	Import Capability (MW)
AMITE SOUTH	Slidel – Front Street 230kV	Marion – Hatisburg 230kV and 1SOXY Unit 1	Thermal	3,622
DSG	Good Hope – Prospect 230kV	Waterford – Churchill 230kV and Ninemile Point Unit 5	Thermal	2,365
*Western	Grimes – MT. Zion 138kV	*Cypress – Honey 138kV and MCPS Full Station	Thermal & Voltage	1,234

* Additional generation or reactive resources are required to maintain voltage/reactive balance under this contingency.
* The limit is with Frontier generation at full capacity during summer peak loading condition. N1G1 would not solve without it.

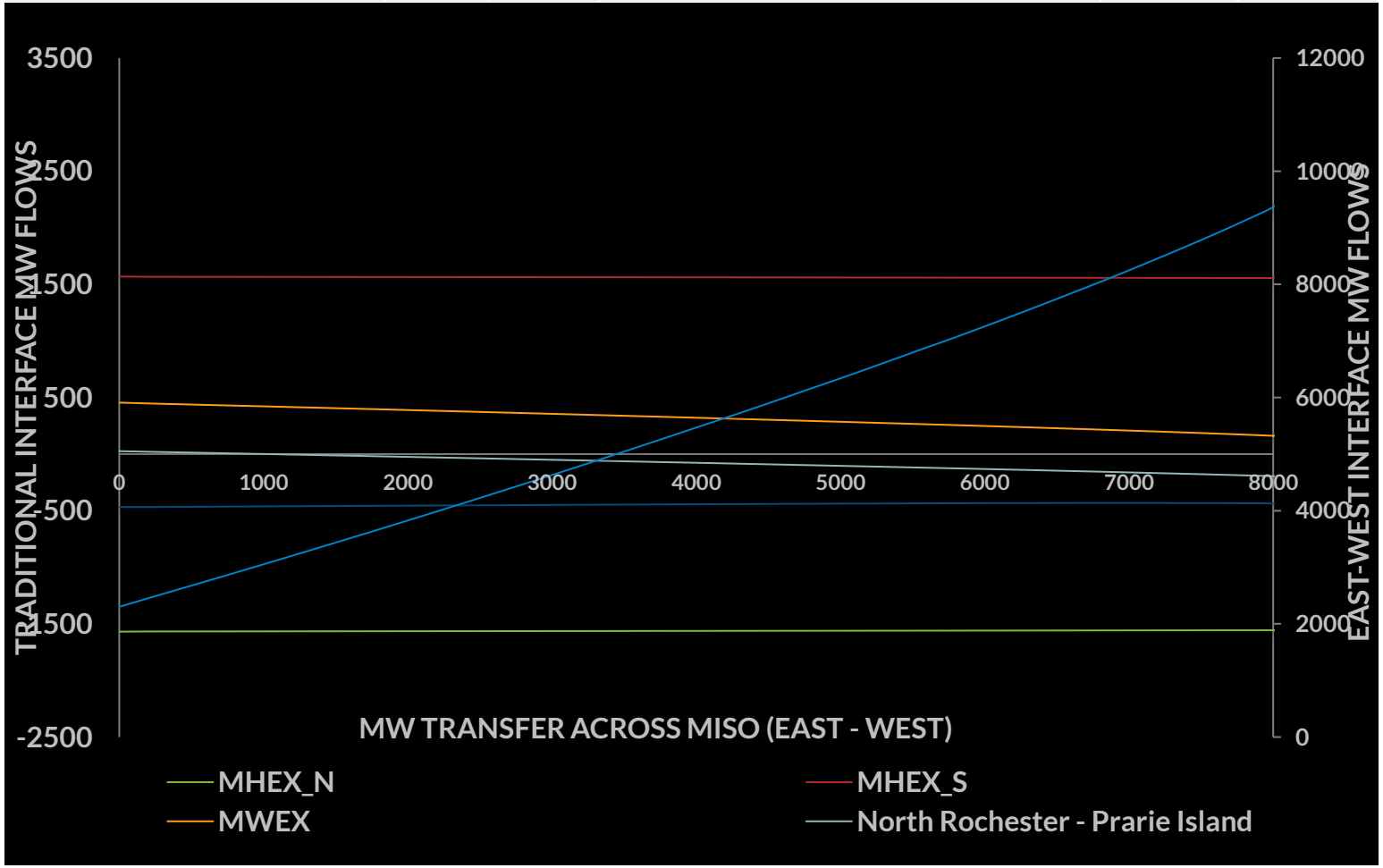
Bidirectional transfer studies across the MISO footprint to identify main constraints with transfers between MISO neighbors

- Transfers across MISO between East and West systems:
  - East system – PJM, SERC (without AECI)
  - West system – SPP and AECI
- Transfer value selected above realistic transfers to identify leading constraints
  - 15,000 MW used
- Flows measured at all tie points and lines bypassing MISO



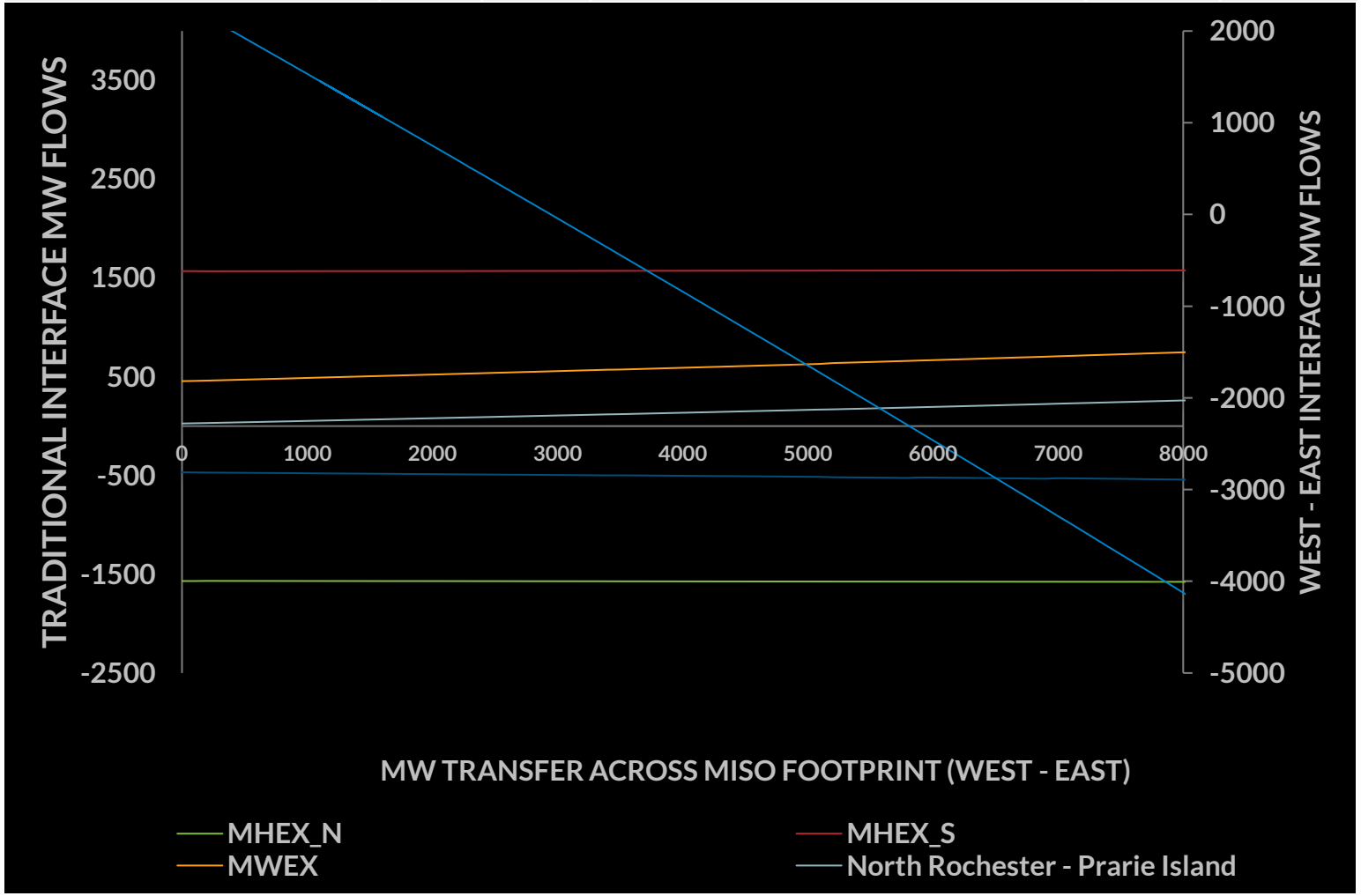
East to West transfer leading constraints and interface flows identified during study

Monitored Facility	Rating	Area	Contingency Name	DC TrLim	AC TrLim
SOUTHLAND - MT HOME 161kV	162	EES_EAI	EA16039: HARRISON EAST-HILLTOP 161	1441.6	1441.6
LAKEOVER 500/230 AT2	615	EES_EMI	EE50X47: LAKEOVER 500/115 AT1	2010.9	2010.9
INDEPENDENCE SES – MOOREFIELD 161	310	EES_EAI	EA16098: QUITMAN - CLINTON WEST 161	3172.9	3172.9



West to East transfer leading constraints and interface flows identified during study

Monitored Facility	Rating	Area	Contingency Name	DC TrLim	AC TrLim
GIBSON – PETERSBURG 345kV	1279	DEI/IPL	CIN34027: BEDFORD-GIBSON 345kV	3710.8	5533.3
PATMOS WEST - LEWISVILLE 115kV	159	EES-EAI	CSW34X40: CROCKETT 345/138 TA TB	5152.2	5347.5
OVERTON 345/161 kV Xfmr	560	AMMO	AEC34014: KINGDOM - MCCREDIE 345kV	6249.5	6249.5



Contact: Fisseha Zewdu, fzewdu@misoenergy.org

MISO

Seasonal Risk / Uncertainty Management

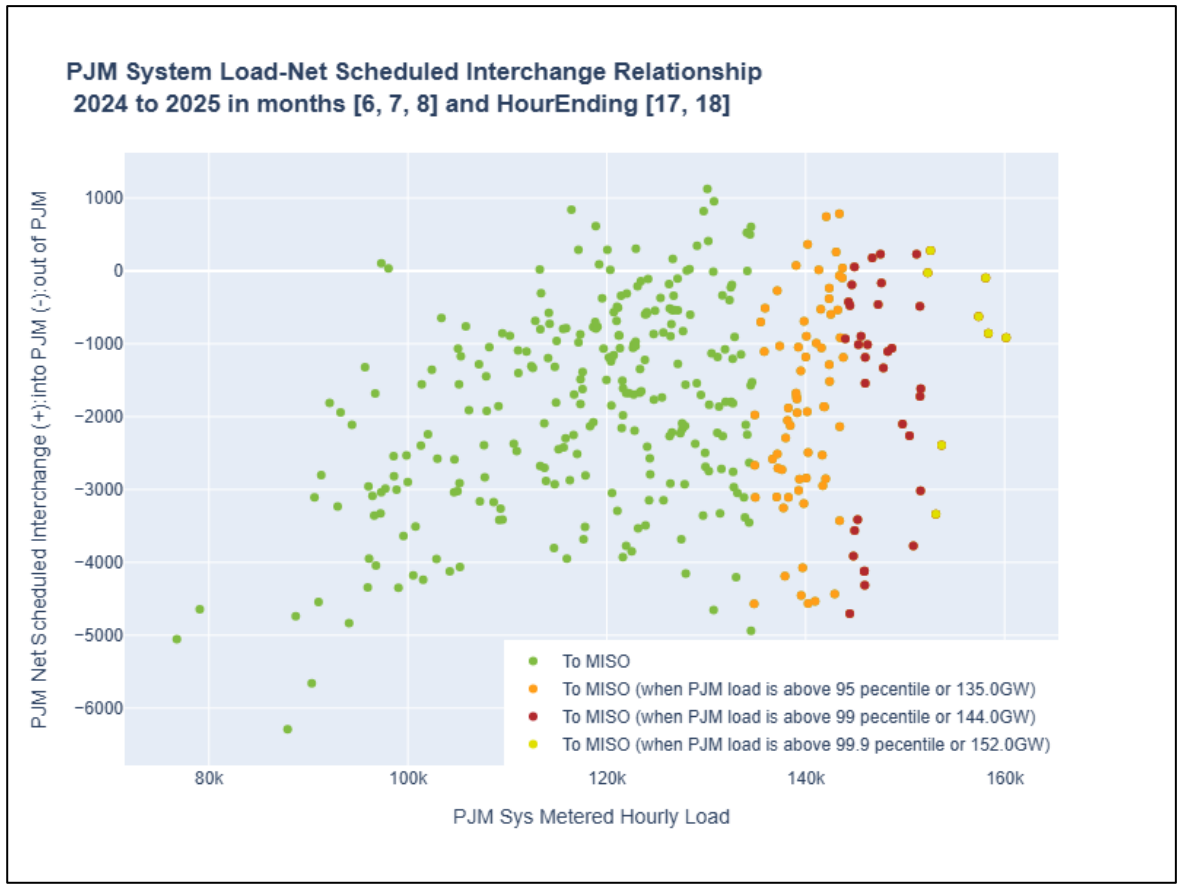
Matt Campbell, Manager, Operations Risk Assessment

Net Scheduled Interchange (NSI)

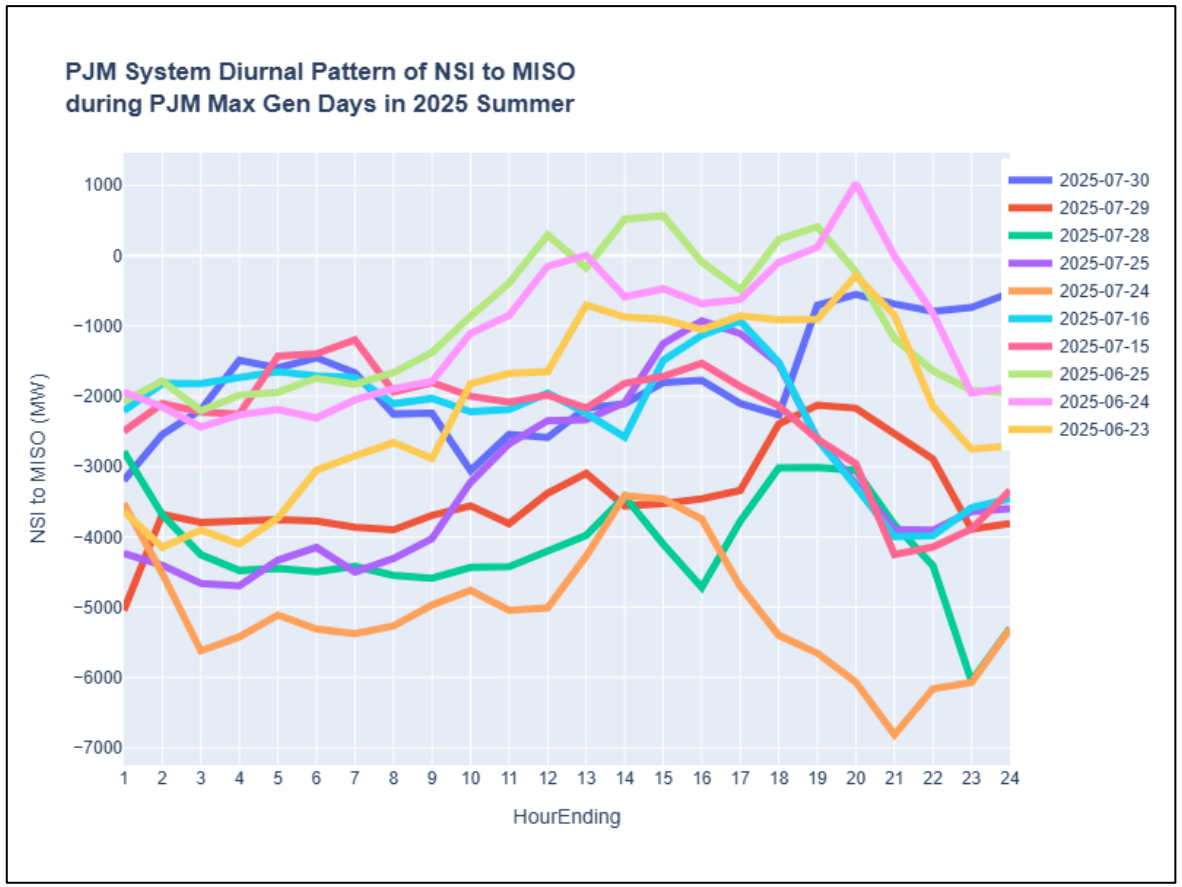
- Using historical NSI-load relationship for NSI risk assessment.
- Actively tracking neighbors' system forecasts, particularly during extreme conditions.

Net Scheduled Interchange Risk

Using historical NSI-load relationship for NSI risk assessment

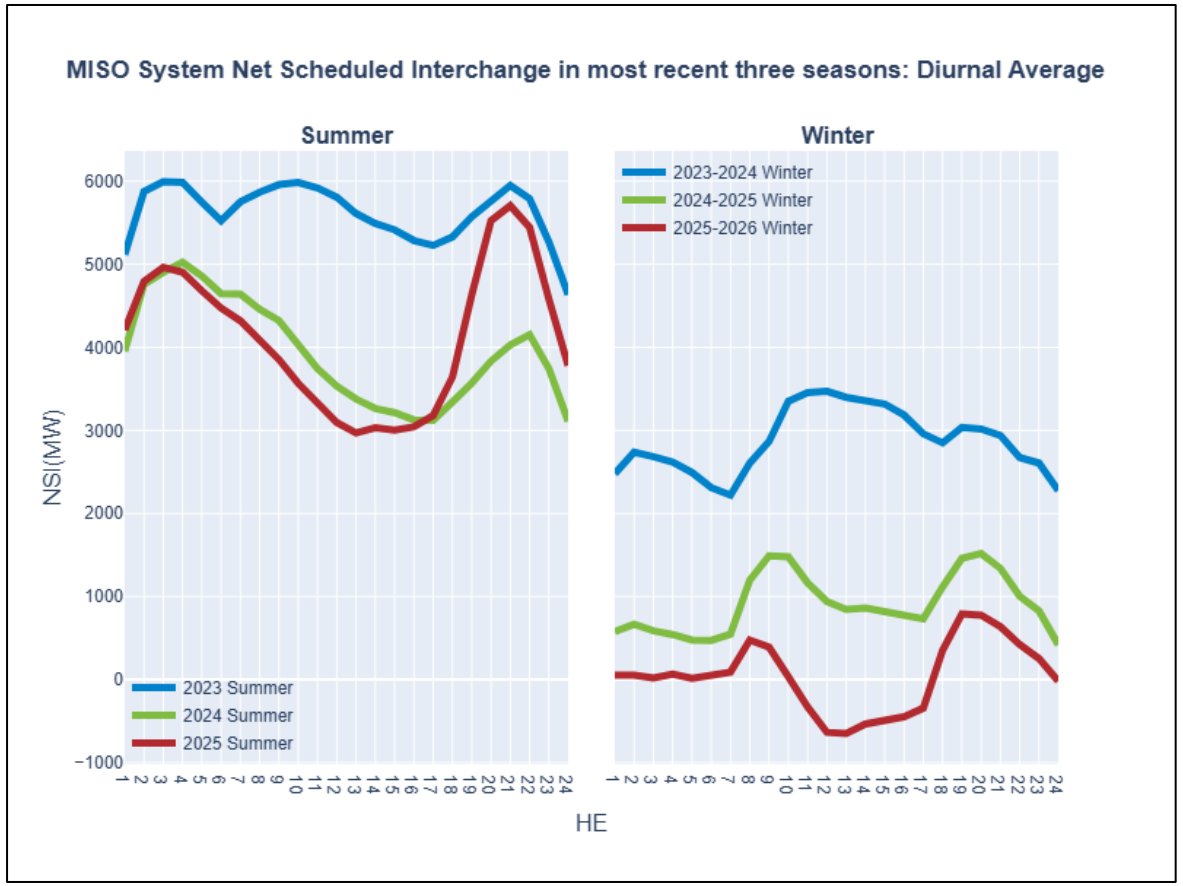


PJM's capability of import energy into MISO has great variation across its Max Gen days

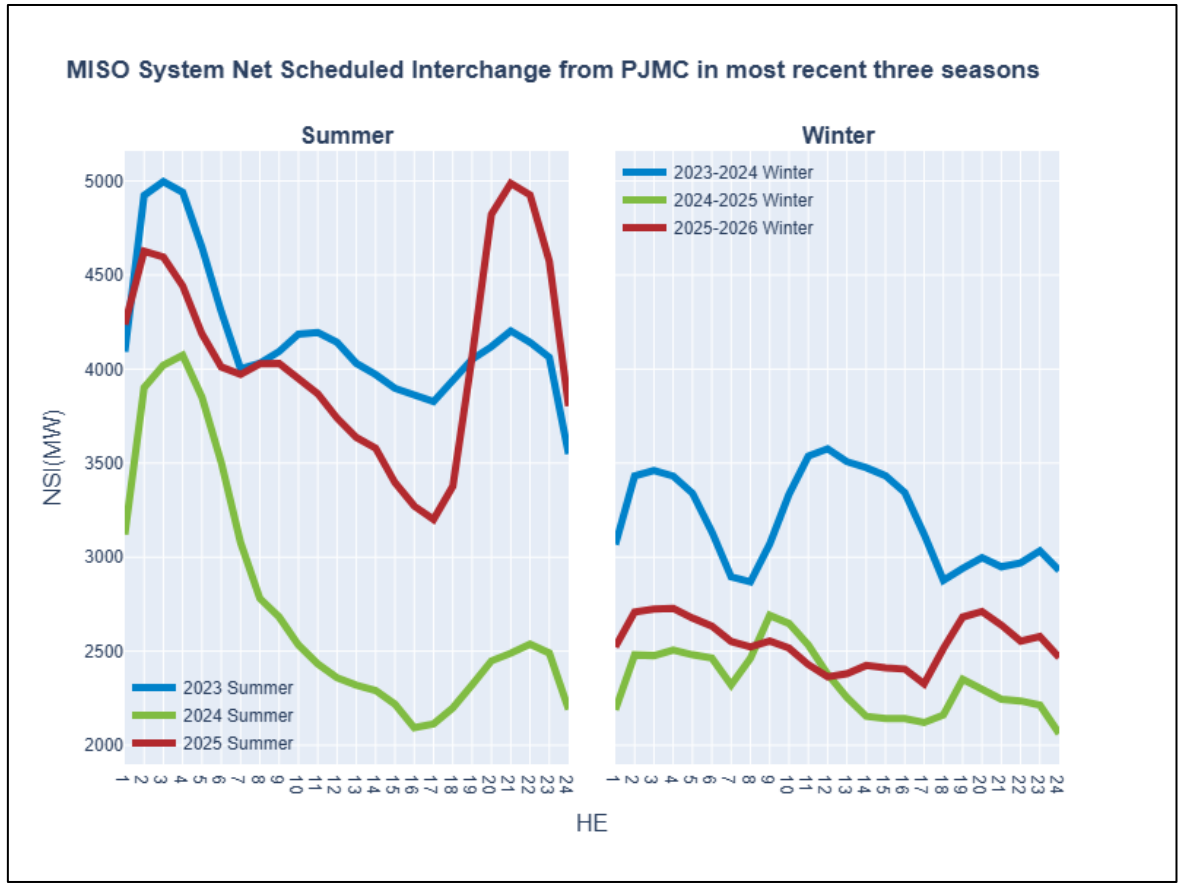


Net Scheduled Interchange Risk

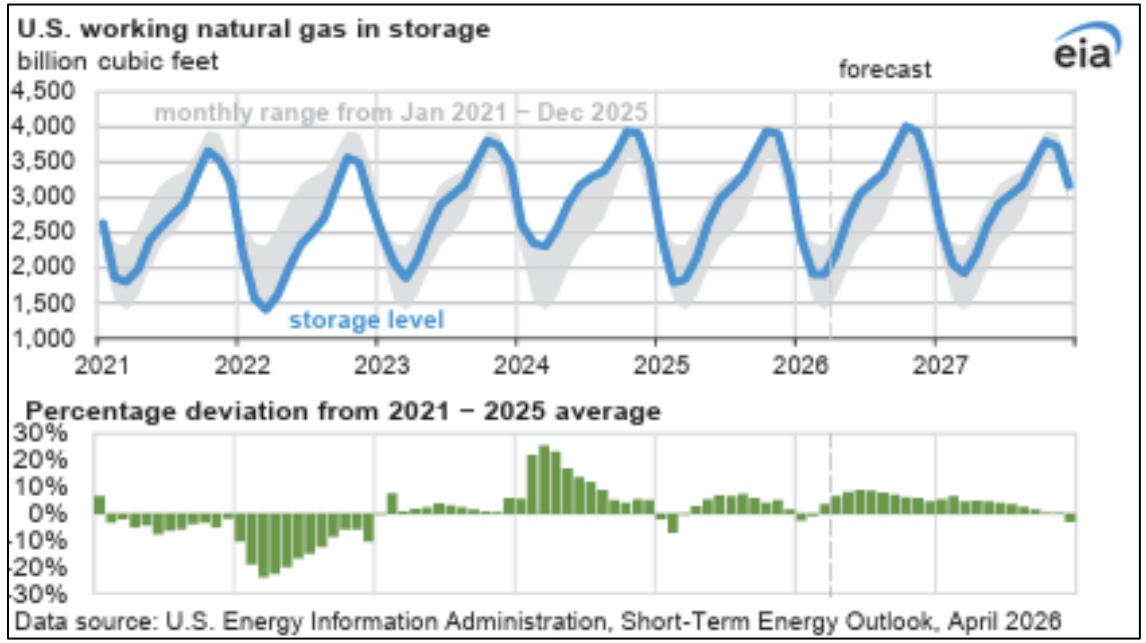
On average, MISO relies more on NSI import during summer months than in winter season



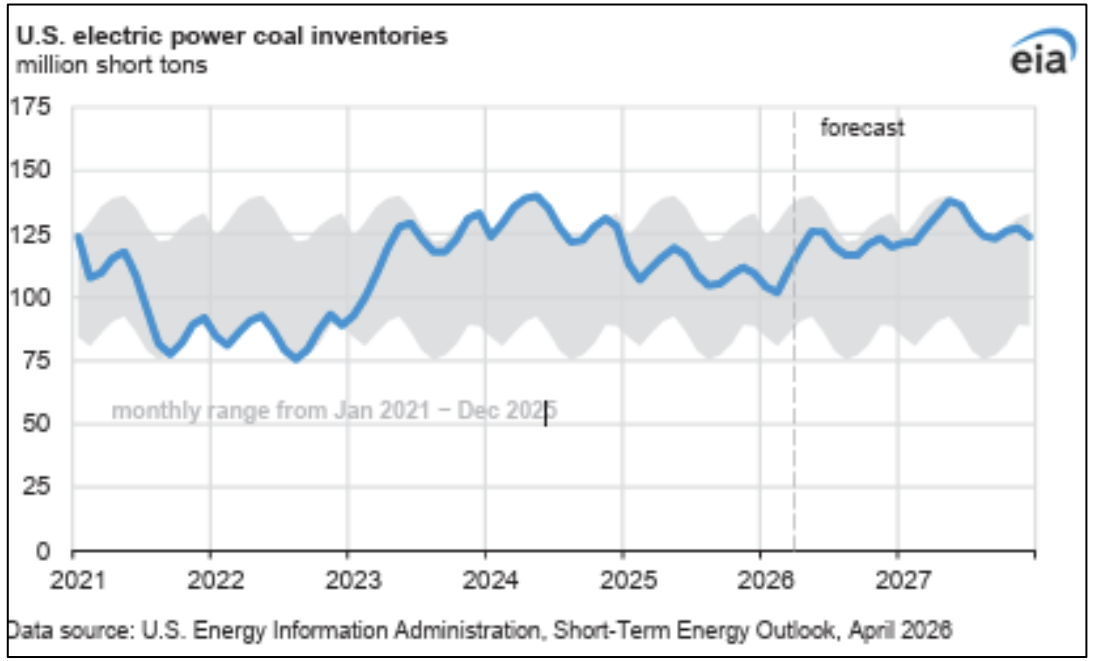
PJM accounts for the bulk of NSI import in summer months, with great variation in past three seasons



Dispatchable Thermal Generation Risk

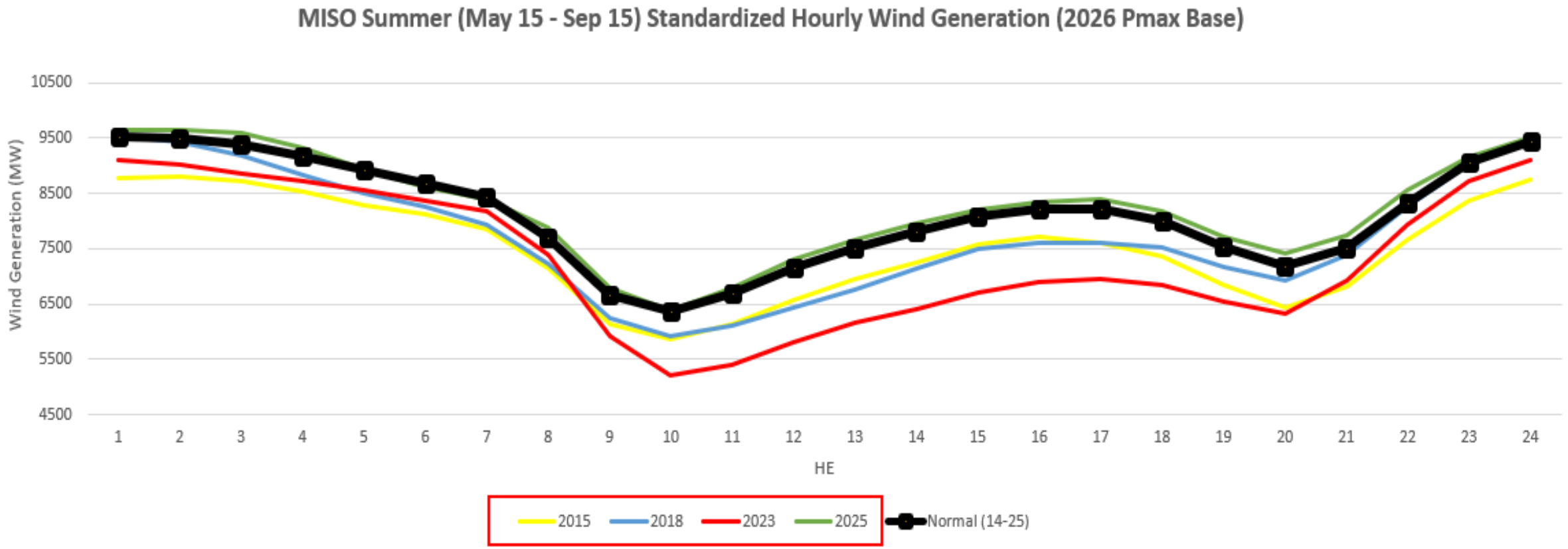


- The balance between natural gas and coal generation will depend on fuel availability and delivery. Natural gas storage is projected to be higher than the 5-year average each month.

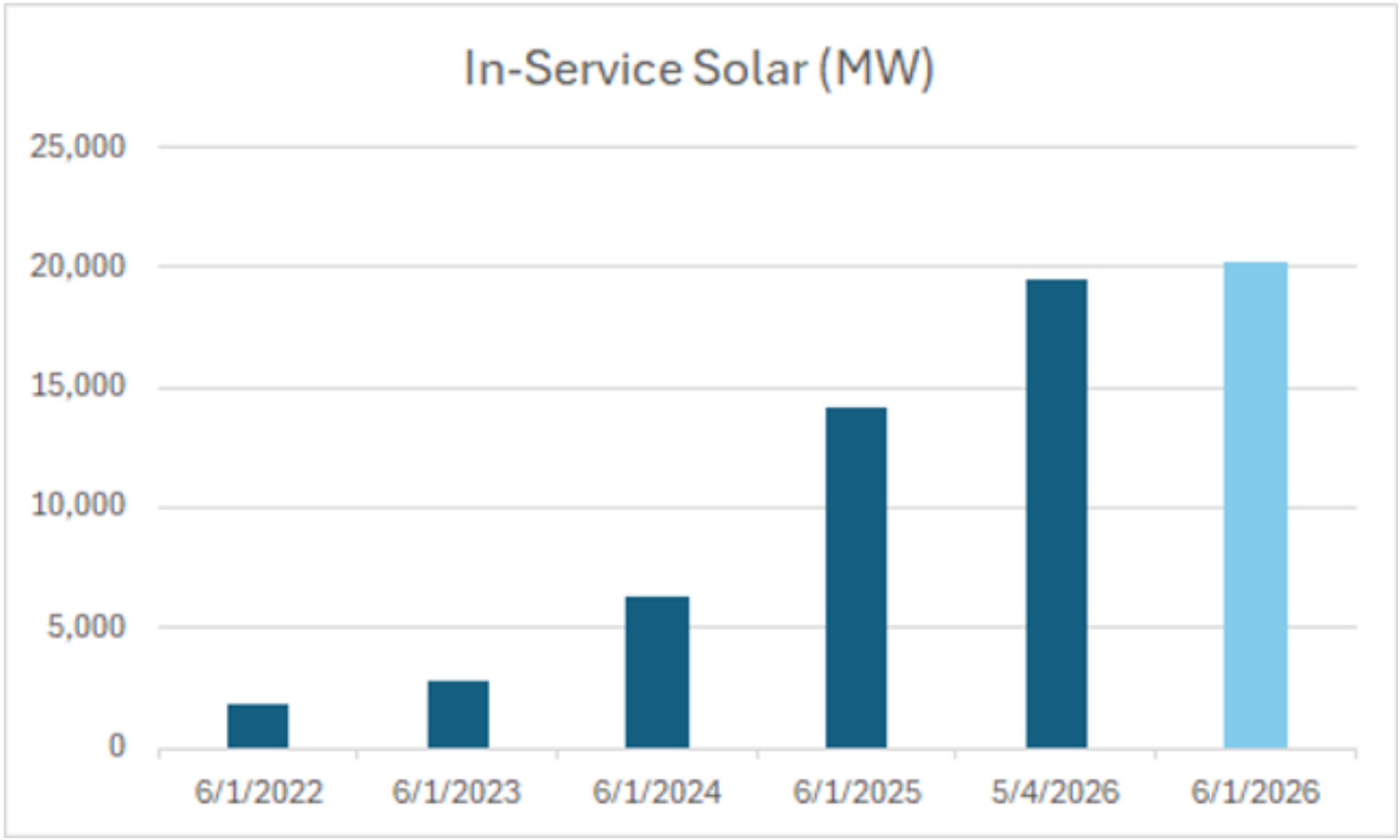


- Coal inventories at power plants are expected to be higher than last summer and on the high end of the 5-year average.

Analog years for summer 2026 indicate **below normal** wind output

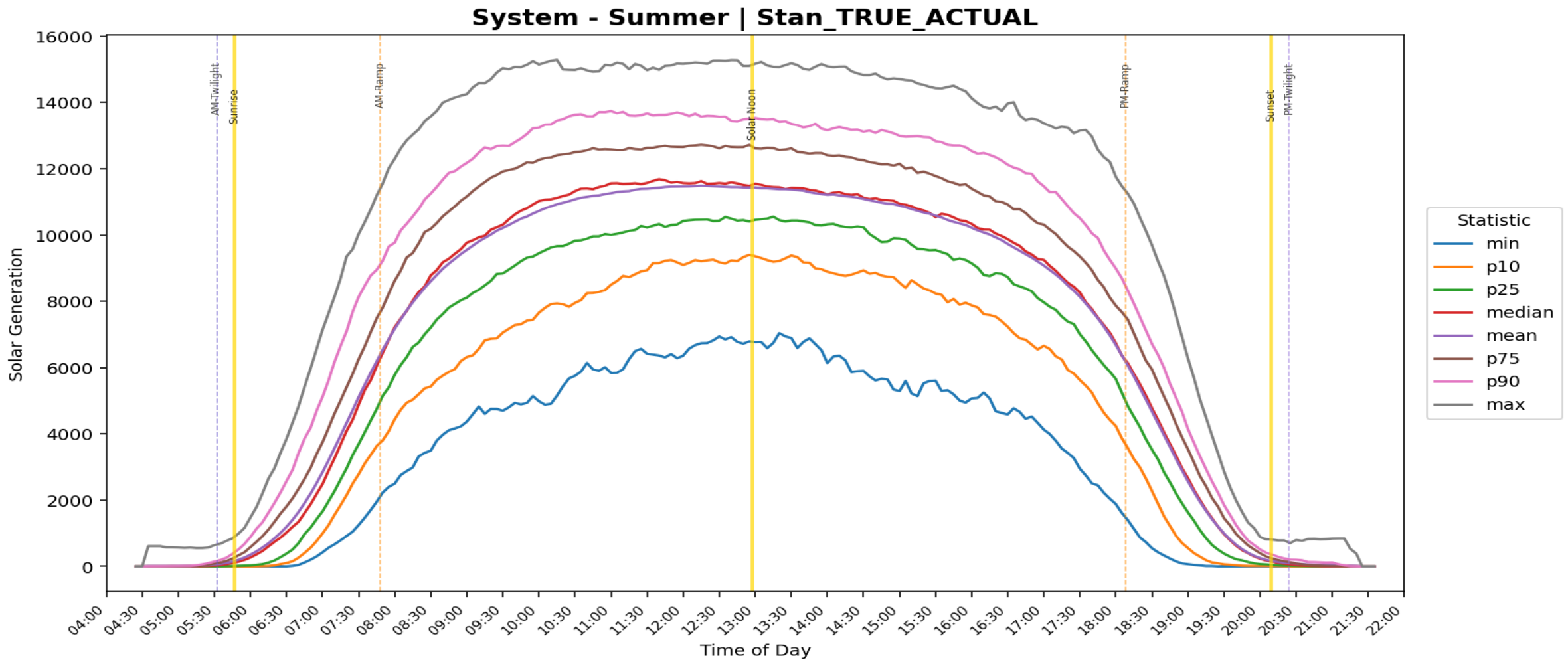


MISO is projected to have 20 GW of solar in our market in June 2026

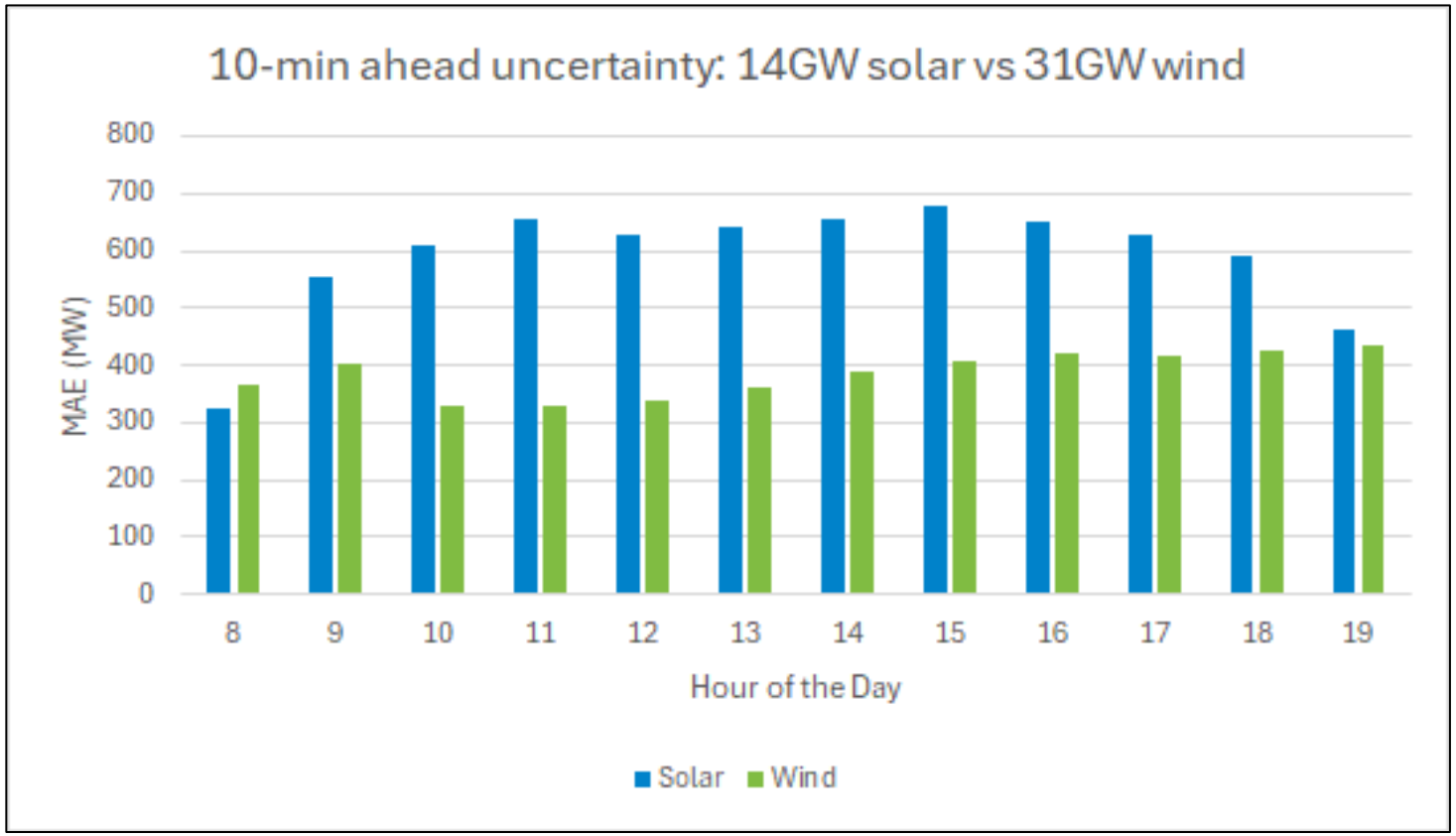


Solar expectations based for summer

Data standardized to latest MISO Pmax: Average daytime solar expected to be ~11 GW

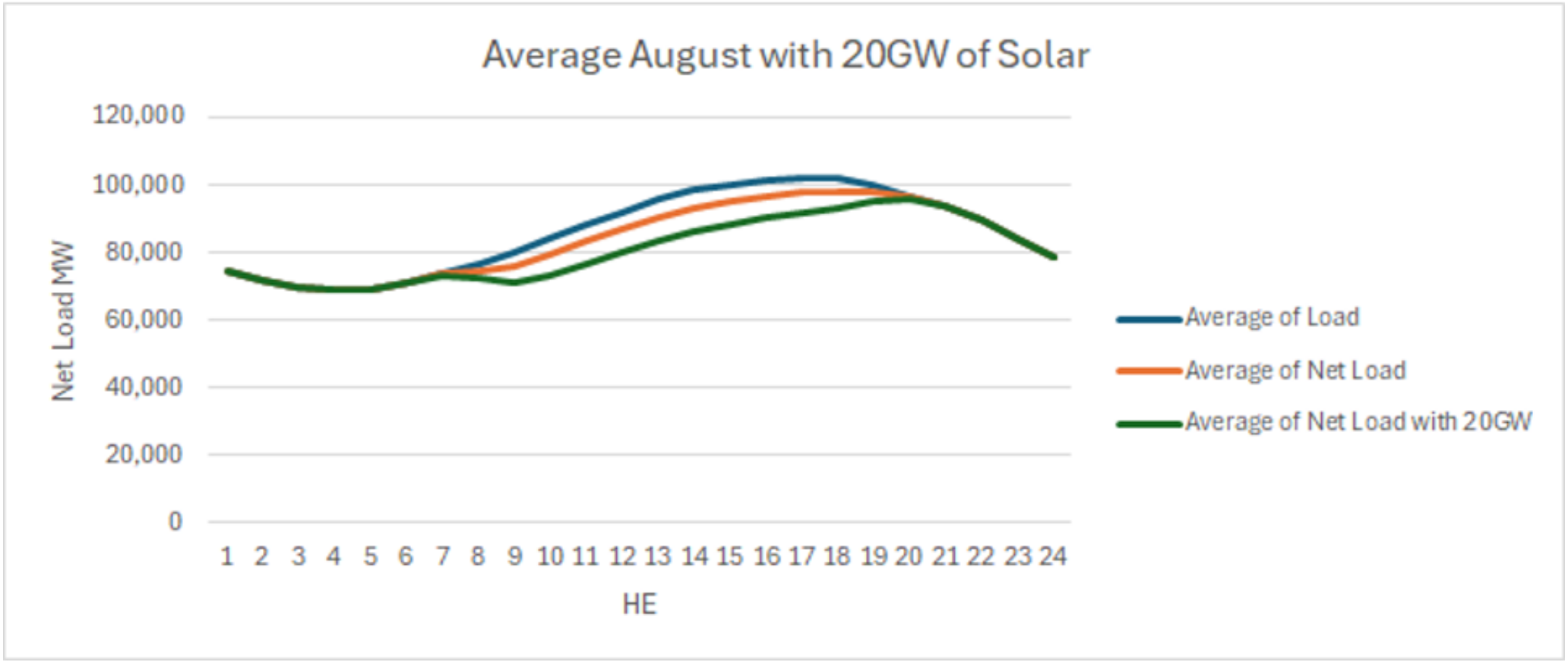


Solar uncertainty more challenging in real time than wind



Performance over last summer

Expected in service solar shifts peak hour from HE17 to HE20



Enhanced uncertainty management based on learned opportunities

- Enhanced quantification models to derive seasonal reserve requirements
- Shift from Peak Hour to ALL HOUR process
- Assess all 24-hour ND-FRAC Net Uncertainty forecast to determine Low/Medium/High prediction for setting Commitment Threshold
- Assess Commitment Threshold across all 24-hour conditional on load and renewable level
- Prepare implementation of Dynamic Regulation Requirement expected June 2026

Assess all 24-hour ND-FRAC Net Uncertainty forecast to determine low/medium/high prediction for setting Commitment Threshold

- A market day will be labeled as low/medium/high based on:
  - L/M/H at peak hour; or
  - Count of M/H hours in a day

Using 3/16/2026 as example:

- Medium at Peak Hour HE 20
- High when counting M/H hrs
- Final determination: HIGH

MKTDAY	HE	Uncertainty
3/16/2026	1	1-Low (Green)
3/16/2026	2	1-Low (Green)
3/16/2026	3	2-Medium (Yellow)
3/16/2026	4	2-Medium (Yellow)
3/16/2026	5	2-Medium (Yellow)
3/16/2026	6	2-Medium (Yellow)
3/16/2026	7	2-Medium (Yellow)
3/16/2026	8	2-Medium (Yellow)
3/16/2026	9	2-Medium (Yellow)
3/16/2026	10	2-Medium (Yellow)
3/16/2026	11	3-High (Orange/Red)
3/16/2026	12	3-High (Orange/Red)
3/16/2026	13	3-High (Orange/Red)
3/16/2026	14	3-High (Orange/Red)
3/16/2026	15	3-High (Orange/Red)
3/16/2026	16	3-High (Orange/Red)
3/16/2026	17	3-High (Orange/Red)
3/16/2026	18	3-High (Orange/Red)
3/16/2026	19	3-High (Orange/Red)
3/16/2026	20	2-Medium (Yellow)
3/16/2026	21	1-Low (Green)
3/16/2026	22	1-Low (Green)
3/16/2026	23	1-Low (Green)
3/16/2026	24	1-Low (Green)

Assess commitment threshold across all 24-hour conditional on load and renewable level

April 13, 2026

Next-Day FRAC Commitment Thresholds Details (ALL HOUR PROCESS)

Select Forecast Market Day: April 13, 2026

Region	PEAKHOUR	ALLHOUR	FINAL	Primary Commitment Threshold	Supplement Commitment Threshold	Commitment Threshold (MW)
Systemwide	Low	Low	Low	5,000	6,600	6,600

Systemwide

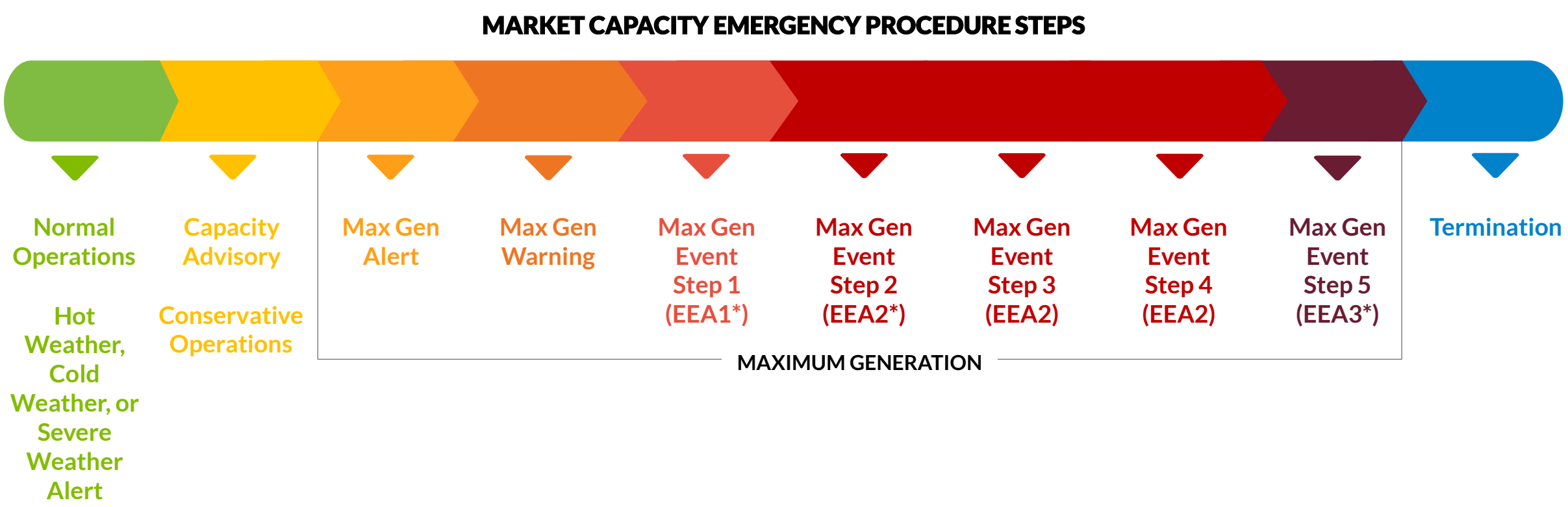
HE	FORECAST MTLF Input	FORECAST WIND Input	Supplement Commitment Th..
1	63,924	20,093	6,300
2	62,525	19,066	4,800
3	61,826	17,677	4,800
4	61,937	16,219	4,800
5	63,573	15,314	4,800
6	65,462	15,070	5,400
7	69,705	14,943	5,400
8	72,904	14,934	5,000
9	74,352	15,010	5,000
10	75,681	15,449	5,000
11	76,982	16,339	5,000
12	78,219	17,366	6,000
13	79,439	18,670	6,600
14	80,021	19,763	6,600
15	80,958	20,249	6,600
16	82,023	20,187	6,600
17	83,027	19,834	6,600
18	83,339	19,167	6,600
19	82,810	18,311	6,000
20	81,993	17,740	6,000
21	80,978	17,392	6,000
22	77,599	17,050	5,000
23	73,018	16,633	5,000
24	68,865	15,965	5,400

Contact: Matt Campbell, mcampbell@misoenergy.org

Emergency Procedure & Capacity Emergency Changes

Don Hunter, Manager, MISO Control Room Operations

Current Procedures through May 30, 2026

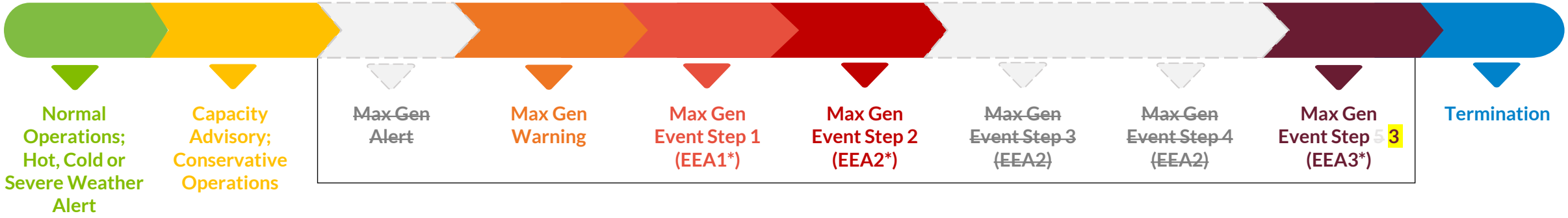


Emergency procedures escalate as capacity conditions tighten; associated actions are designed to balance the real-time supply of energy with demand on the system

*See appendix for definitions

What's Changing

PROPOSED MARKET CAPACITY EMERGENCY PROCEDURE STEPS



CHANGES INCLUDE

- Eliminate Maximum Generation Alert
- Move procedure Step 1a (commitment of emergency-only resources) from Step 1 to Maximum Generation Warning
- Merge Maximum Generation Steps 3 and 4 with Step 2
- Rename Maximum Generation Event Step 5 to Event Step 3

*See appendix for definitions

Effective June 1, 2026

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

Emergency procedures escalate as capacity conditions tighten; associated actions are designed to balance the real-time supply of energy with demand on the system

*See appendix for definitions

The grid conditions gauge on MISO's website reflects active market capacity conditions for members and the public

Green	Yellow	Orange	Dark Orange	Red
Grid is stable and conditions are normal	*Grid is stable and advisories or warnings are issued*	*Grid is stable and power demand could exceed supply available*	*Grid is stable and emergency power and/or reduced demand is needed*	*Power interruptions imminent or happening*
Hot Weather Alert	**Capacity Advisory**	**NERC Energy Emergency Alert 1 (EEA1)**	**NERC Energy Emergency Alert 2 (EEA2)**	**NERC Energy Emergency Alert 3 (EEA3)**
Cold Weather Alert	**Conservative Operations**			
Severe Weather Alert	**Maximum Generation Warning**			

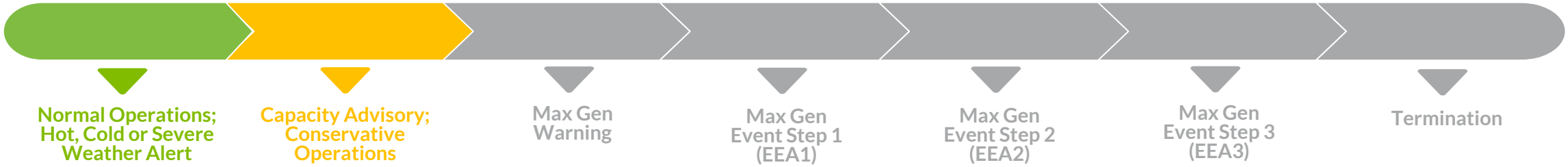
Grid Conditions Gauge vs. Capacity Emergency Notifications

The gauge needle moves when an alert, advisory, warning, event or termination *takes effect*, not when a notification is sent. Notifications take precedence over what is seen on the gauge.

Grid Conditions at a Glance

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

(1 of 3)



STATUS	TRIGGER	COMMUNICATION	AVAILABLE MISO ACTIONS*	REGULATORY	STAKEHOLDER/MEDIA
Normal Operations	None	None	Normal operating procedures	None	None
Hot, Cold, or Severe Weather Alert	Could be approaching tight supply due to weather-related circumstances, like extreme heat or cold, or severe wind, storms, and tornados	**Alert for situational awareness**	• Review outage plans for deferral or cancellation • *Normal pricing*	MISO alerts FERC, NERC, DOE, State Commissions, and Regional Entities	• Message to members and neighboring RCs through Operator Interface and RCIS • Notification posted to MISO website • Email sent to Real-Time Market Mailing List
Capacity Advisory	Capacity shortage is forecast within the next few days	**Advisory for situational awareness**	• Request market participants update offer data • Allows MISO to line up LMRs that are unavailable under normal operating conditions • Increase STR requirements • *Normal pricing*	Same as above	Same as above
Conservative Operations	Reliability issue possible for defined area (may be capacity-driven or caused by other abnormal circumstances)	**Alert for situational awareness**	• Potentially suspend transmission maintenance • Review outage plans for deferral or cancellation • Define boundaries • Suspend maintenance • *Normal pricing*	Same as above	Same as above

*MISO's Shift Manager determines which actions are needed and that is shared through Operator Interface.
See appendix for definitions

Effective June 1, 2026

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

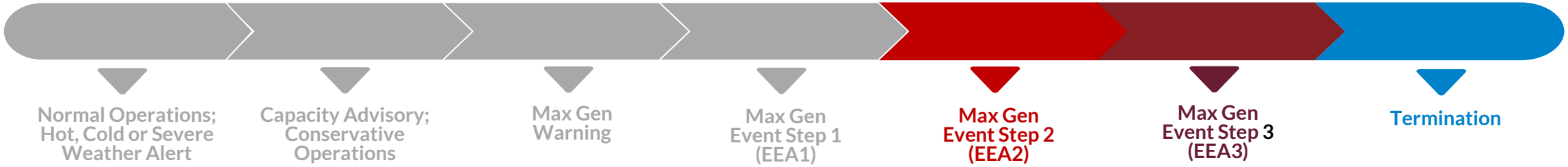
(2 of 3)

STATUS	TRIGGER	COMMUNICATION	AVAILABLE MISO ACTIONS*	REGULATORY	STAKEHOLDER/MEDIA
Maximum Generation Warning	Reserve margin shortage is forecast	**Warning to prepare for possible event**	• Declare *Conservative System Operations* • Prepare for potential Maximum Generation event • Schedule all available economic resources • Curtail non-firm exports • Reconfiguration • Commit emergency-only resources** • Request environmental waivers as appropriate • *Emergency Tier 1 Offer Floor*	Same as above	Same as above
Maximum Generation Event Step 1 (EEA1)	Reserve margin requirements cannot be met through normal economic resources; all available resources in use	**Declare EEA1**	• Activate emergency operating ranges • *Emergency Tier 1 Offer Floor*	• EEA Notification • MISO NERC Alert • MISO contacts state/local leaders	MISO corporate communications initiates contact with impacted member communicators

*MISO's Shift Manager determines which actions are needed and that is shared through Operator Interface.
**Moved from previous Step 1a
See appendix for definitions

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

(3 of 3)

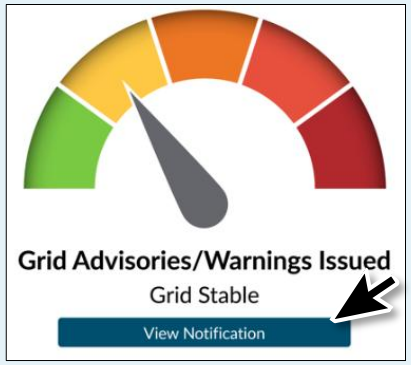


STATUS	TRIGGER	COMMUNICATION	AVAILABLE MISO ACTIONS*	REGULATORY	STAKEHOLDER/MEDIA
Maximum Generation Event Step 2 (EEA2)	Demand cannot be met; actions needed to reduce demand and/or acquire additional supply	**Declare EEA2**	• Instruct load to be reduced via LMMs-Stage 1 or Stage 2 and LMRs or EDRs • Implement emergency energy purchases • Instruct LBAs if public appeals needed** • Implement spinning and supplemental reserves • Request and implement environmental waivers • Initiate external emergency energy purchases • *Emergency Tier 2 Offer Floor*	Same as above	Same as above
	Attempting to maintain minimum Contingency Reserves				
	All available MISO resources used				
Maximum Generation Event Step 3 (EEA3)	Unable to maintain minimum Contingency Reserves	**Declare EEA3**	• Coordinated load shed • *VOLL pricing*	Same as above	Same as above
Termination	Max Gen and, possibly, Capacity Advisory termination	**Event terminated**	• Update stakeholder market data • *Normal pricing*	Same as above	Same as above

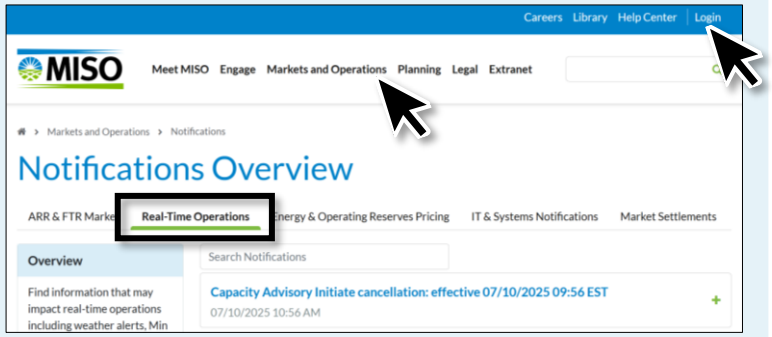
*MISO's Shift Manager determines which actions are needed and that is shared through Operator Interface.
**Public appeals to reduce demand is based on internal LBA procedures, system conditions and Event projections provided by MISO
See appendix for definitions

View MISO's real-time grid status and subscribe to notifications

Website



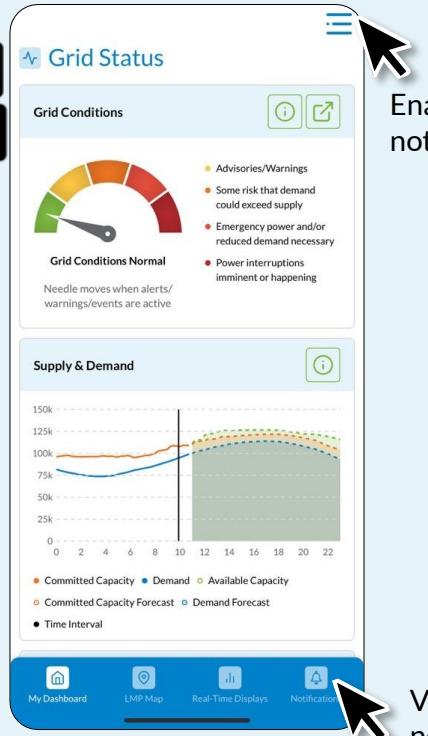
Grid Conditions Gauge
(Homepage)



Real-Time Operations Notifications
(Markets and Operations > Notifications > Real-Time Operations)
Login to subscribe to email notifications

MISO App

Download on the App Store
GET IT ON Google Play



Enable notifications

View notifications

Grid Conditions Gauge
(My Dashboard)

Real-Time Operations Notifications
(Notifications > Real-Time Operations)

Social Media

@MISO_energy

Midcontinent Independent System Operator (MISO)

Public Notifications on Website & Email

- Public declarations will include time and impacted region(s) and entity(ies)
- Notifications will be posted to the website and sent via the Real-Time Notification email list
- Operating instructions will be shared via Operator Interface only
  - Full and view-only access is managed by each LBA, TO or MP

Notification

Severe Weather Alert

04/04/2026 9:21 AM EST

MISO has issued a Severe Weather Alert due to High Winds and Heavy Rainfall.

Start Time: 04/04/2026 09:15 EST

End Time: 04/04/2026 20:00 EST

Affected Region(s):

- South Region - EES, CLEC, LAFA, SME, EAI, EMBA

This public notification is for awareness only. Impacted entities receive detailed instructions and information via the Operator Interface.

Visit https://help.misoenergy.org/ for more information

New Public Appeal Notification on Website & Email

MISO will issue separate notifications for Public Appeals. This action is at the discretion of the shift manager when in EEA2.

- Notifications will be posted to the website and sent via the Real-Time Notification email list

Notification

Public Appeal Notification

06/01/2026 7:17 AM EST

MISO has instructed the utilities listed below to issue a public appeal for electricity conservation due to reduced power supply and high demand.

Start Time: 06/01/2026 09:15 EST

Affected Region(s):

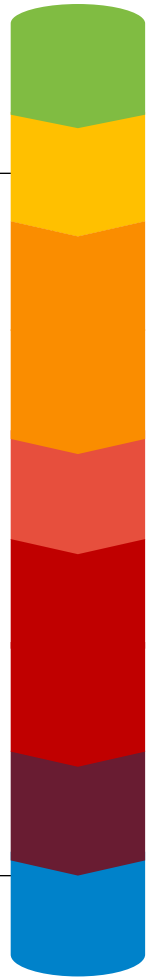
- North Region – DPC, GRE, MDU, MP, NSP, OTP, SMP

This public notification is for awareness only. Impacted entities receive detailed instructions and information via the Operator Interface.

Visit https://help.misoenergy.org/ for more information

The emergency operating procedures address adverse conditions by signaling conditions to MISO's members and allowing or requiring certain actions

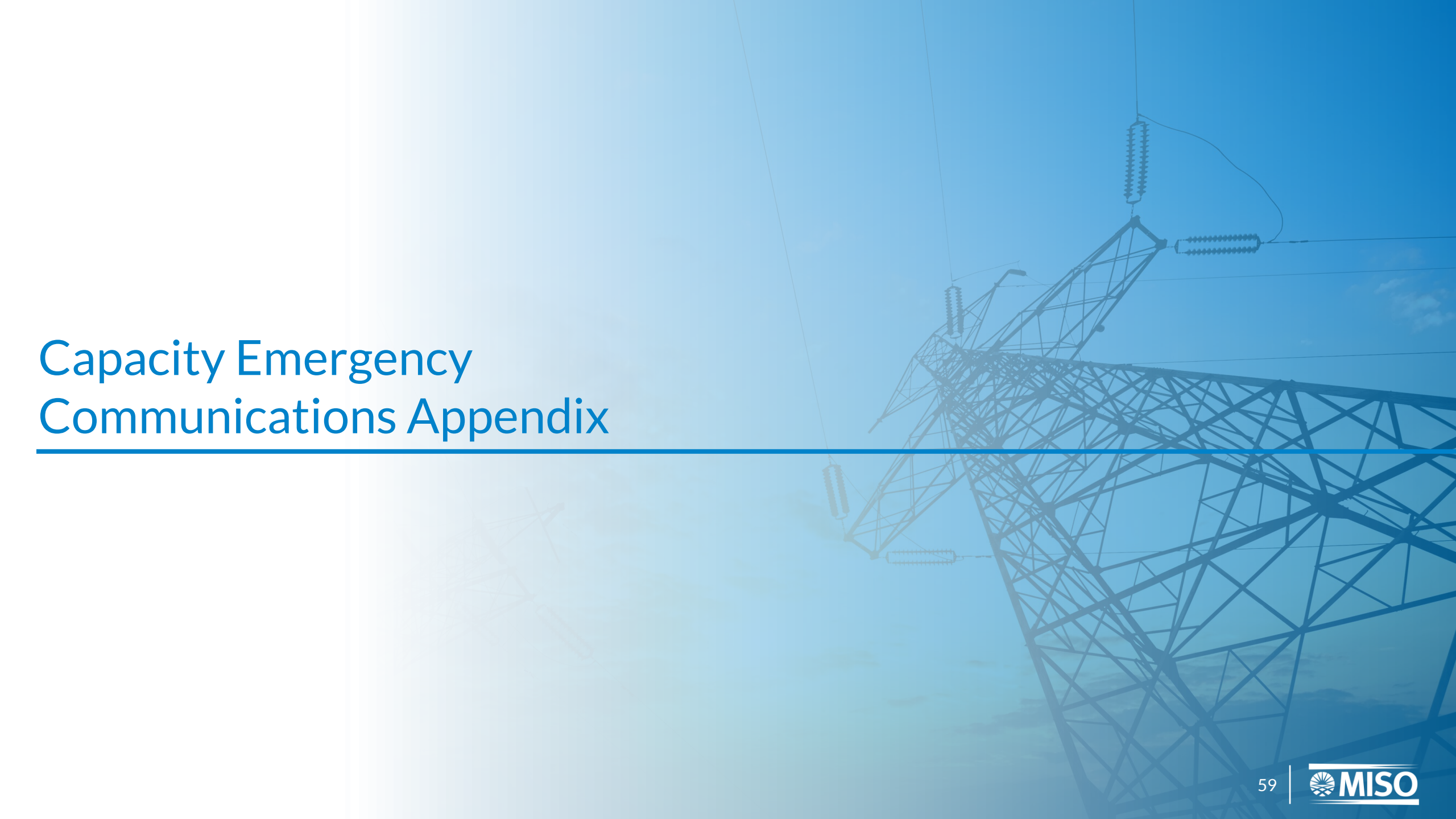
MARKET CAPACITY EMERGENCY PROCEDURE STEPS



Normal Operations		
Capacity Advisory	Advance notice of forecasted capacity shortage; request stakeholders update offer and market data; updated STR and STR RPE values; declare Conservative System Operations if conditions warrant	Normal Pricing
Warning	Request MPs/LBAs ensure accuracy of LMM/LMR availability and self-scheduled values; send LBAs LMM survey; commit available economic resources; coordinate reconfiguration with RCs/TOPs; schedule external/internal Module E resources; suspend CTS, evaluate TEC/inadvertent payback; curtail export schedules; request waivers; implement reconfiguration options; commit AME resources	Emergency Pricing Tier 1 Offer Floor
Event Step 1	Declare NERC EEA1; activate emergency limits	
Event Step 2	Declare NERC EEA2; implement LMRs, LMMs (Stage 1 or 2); commit EDRs; emergency energy purchases; public appeals; implement waivers; utilize operating reserves; implement CRSG reserve call; emergency reserve purchases	Emergency Pricing Tier 2 Offer Floor
Event Step 3	Declare NERC EEA3; firm load shed; set LMPs and MCPs to the VOLL	VOLL* Pricing
Termination	Terminate declarations and return to normal pricing	Normal Pricing

See appendix for definitions

Capacity Emergency Communications Appendix



Some declarations are *not* driven by capacity challenges

Transmission

Transmission Advisory

Notification of forecasted transmission system conditions that may adversely impact the BES but do not yet warrant a Conservative Operations declaration.

Load Pocket Advisory

Notification of potential capacity concerns within a load pocket where the loss of transmission into the area or generation in the load pocket could lead to additional reliability actions.

NEW

JUNE 1

Transmission Warning

Notification that system conditions present a credible risk to the BES, where mitigation actions are expected to be insufficient and more than 100 MW of load may be lost.

Transmission Emergency

Notification of actual or imminent IROL exceedance requiring immediate emergency actions to maintain BES reliability and prevent widespread impacts.

System Status Levels

Indicates infrastructure failures at MISO or MISO Member facilities

SSL 0 Low – Green

System status is normal. No adverse impacts

SSL 1 Elevated – Yellow

Short, minor impact to system, can be quickly remedied

Examples: Temporary infrastructure issue

SSL 2 High – Orange

Longer term, major impact to system, cause unknown

Examples: Loss of monitoring data or member infrastructure

SSL 3 Severe – Red

Major impact on MISO's ability to reliably operate system or market

Examples: Hardware failure, bomb threat, sabotage, control center evacuation

See Appendix for definitions

Notification for a capacity emergency (EEA) is different from a transmission emergency

Capacity Emergency

Occurs when there is not enough generation to meet demand

Typically linked to extreme weather (summer or winter peak)

Follows MISO's Maximum Generation and NERC's Energy Emergency Alert (EEA) process

Supported with various communications including advisories, declarations, EEA Alerts and website updates

Transmission Emergency

Occurs when there is an actual or imminent IROL violation on the transmission system

Happens very quickly with no public declarations

Requires corrective action within 30 minutes to maintain grid stability

Follows MISO's Transmission System Emergency process

See Appendix for definitions

Definitions

Contingency Reserves	A type of operating reserve that is held to address the loss of a significant generating unit or transmission line. At MISO, this is the sum of supplemental and spinning reserves.
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. EDRs are operated outside the Operator Interface (OI) by the shift manager by using the EDR Tool.
Energy Emergency Alert Level 1 (EEA1)	A NERC-mandated alert when all available generation resources are in use. It means MISO is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
Energy Emergency Alert Level 2 (EEA2)	A NERC-mandated alert when load management procedures are in effect. It means MISO is no longer able to provide its expected energy requirements and is an energy deficient. MISO has implemented its operating plans to mitigate emergencies and is still able to maintain minimum contingency reserve requirements.
Energy Emergency Alert Level 3 (EEA3)	A NERC-mandated alert when firm load interruption is imminent or in progress. It means MISO is unable to meet minimum contingency reserve requirements.
Interconnection Reliability Operation Limit (IROL)	A NERC System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System.
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.
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, cannot 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.
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
Maximum Generation Capacity Warning (Max Gen)	MISO foresees or is experiencing conditions where all available economic Resources are committed to meeting Load, firm transactions, and reserve requirements, and is concerned about sustaining required Operating Reserves.
Reserve Margin	The difference between total operating reserves and the operating reserve requirement. MISO is required to keep a certain reserve margin to ensure there is enough capacity to meet peak demand, plus a buffer.
Short-Term Reserve (STR)	A 30-minute rampable generation capacity product. It's designed to address short-term needs for managing system reliability.
Spinning Reserves	Reserves held that are synchronized to the system and available immediately.
Supplemental Reserves	Reserves for abnormal supply deficiencies that must be ready within 10 minutes.
System Operating Limit (SOL)	The NERC value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria.
Value of Lost Load (VOLL) Pricing	The price at which MISO values the cost of unserved energy; essentially, what customers would be willing to pay to avoid an outage.

202(c) Emergency Orders

Don Hunter, Manager, MISO Control Room Operations

Department of Energy 202(c) Orders

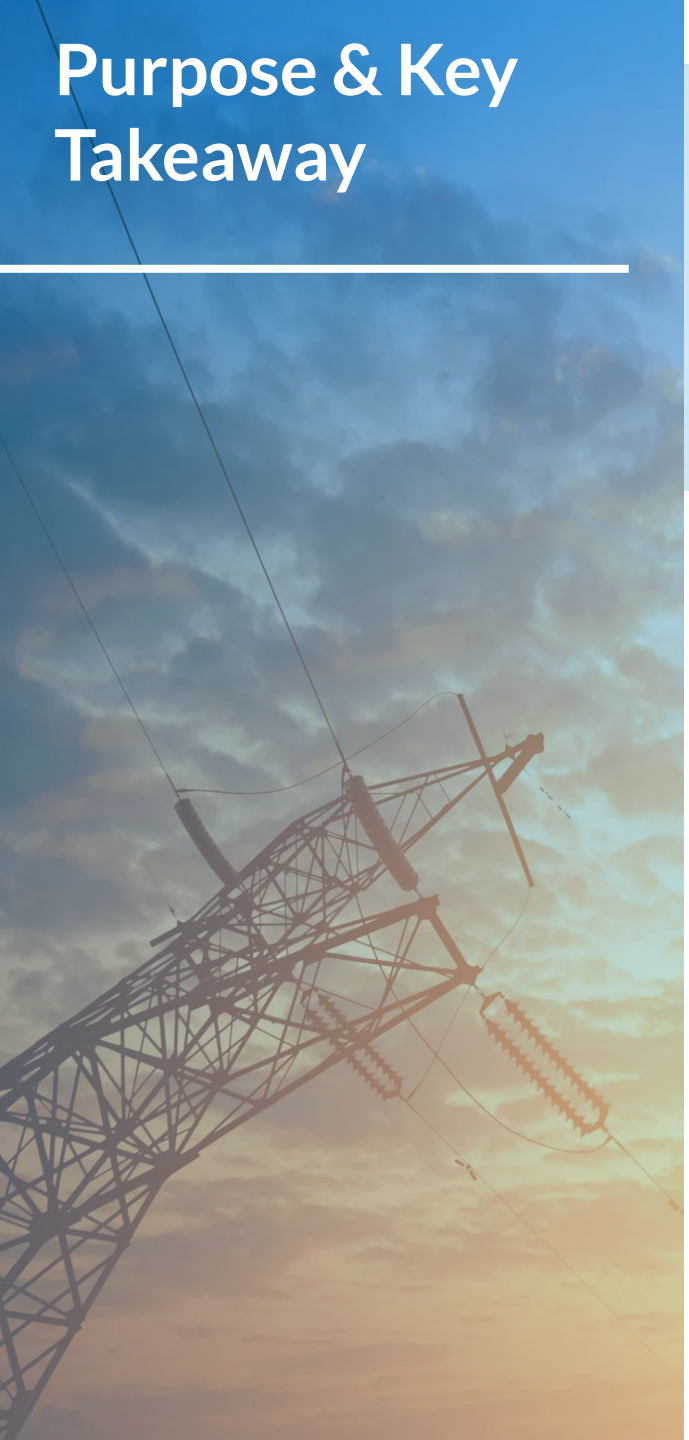
- Section 202(c) of the Federal Power Act (FPA)
  - Authorizes the Department of Energy (DOE) to issue emergency orders
    - Require power plants to remain in operation in lieu of retirement
    - Permit generators to exceed environmental operating limits
    - Direct backup generation facilities to run when EEA3 is imminent
  - MISO did not use 202(c) during Winter Storm Fern
    - Actions taken prior to use of the 202(c) sufficient to relieve capacity issues

Contact: Don Hunter, dhunter@misoenergy.org

Transmission System Emergency Procedure Updates

Clayton Umlor, Manager, MISO Reliability Coordination

Purpose & Key Takeaway



Purpose

Communicate improvements coming to the Transmission System Emergency (TSE) procedure to enhance operational readiness.

Key Takeaways

- Transmission Warning declaration is a tool to communicate an increased level of transmission risk (internally & externally)
- Transmission System Emergency procedure updates are drafted and under review for inclusion of the Transmission Warning declaration to be effective June 1, 2026
- Future updates of the procedure will include clarifying criteria and responsibilities for identifying Transmission System Emergencies in both real-time and planning processes

Transmission Warning Entrance Criteria

Transmission Warning Declaration: Notification that system conditions present a credible risk to the BES, where mitigation actions are expected to be insufficient and more than 100 MW of load may be lost.

A transmission warning will be declared when…

ALL of the following conditions are met:

- There is 100 MW or more of load at risk
- Normal congestion management tools have been exhausted and are not sufficient to mitigate risk
- Available emergency actions are not sufficient to mitigate risk (e.g., emergency ranges of units, emergency only units, EDRs, and LMRs, etc.

AND

AT LEAST ONE of the following applies:

- Facilities > 100kV have post-contingent flow greater than or equal to 115% of the highest emergency limit
- The RC determines that system conditions warrant heightened awareness of potential transmission risk

Transmission Warning Exit Criteria

A transmission warning should be terminated when…

EITHER of the following conditions apply:

- The criteria for declaring the Transmission Warning are no longer satisfied
- RCs and TOPs agree that the risk no longer poses a significant threat to load shed or load loss

Timeline & Upcoming Procedure Updates

Transmission Warning: June 1

Criteria and responsibilities for defining Transmission System Emergencies and IROLs are currently being evaluated in the MISO stakeholder processes.

TSE procedure redline document will be posted and available for review.

TSE/IROL criteria & responsibility changes expected Q4 2026

Contact: Clayton Umlor, CUmlor@misoenergy.org

Technical Development & Training Updates

Anita Hurst, Sr. Manager, MISO Technical Development

MISO & Member Summer Readiness Training

Market Capacity Emergency Drill

- Review of recent procedural changes and escalation flow (rev 23 vs rev 24)
- Reinforces how procedure updates affect operational decisions and communications
- Practice applying revised steps of the updated MISO Market Capacity Emergency procedure (SO-P-EOP-11-002, rev 24)

Hurricane Drill

- Overview of 2025 season and vendor forecasts for 2026
- MISO and Member roles before landfall, during, and following a hurricane
- Three separate, simulated scenarios spanning one storm from pre-to-post-landfall; scenarios covered:
- Supply Surplus (Min Gen Event)
- Tool Failure (Loss of State Estimator)
- Restoration efforts (Including the islanding or generation facility, requiring use of blackstart resources)

MISO Operator Summer Readiness Training

Drill Participation

- MISO operators participate in Hurricane Drill and Market Capacity Emergency Drill

Interconnection Reliability Operating Limit (IROL) Simulation Training

- Define, identify, and mitigate System Operating Limits and IROLs
- Declare Transmission System Emergencies

Contact: Anita Hurst, ahurst@misoenergy.org

Thank you for joining us today!

NERC

2025 LTRA Sensitivity Case:

Addition of ERAS Resources in the MISO Assessment Area

April 2026

POWERING TODAY. PROTECTING TOMORROW.

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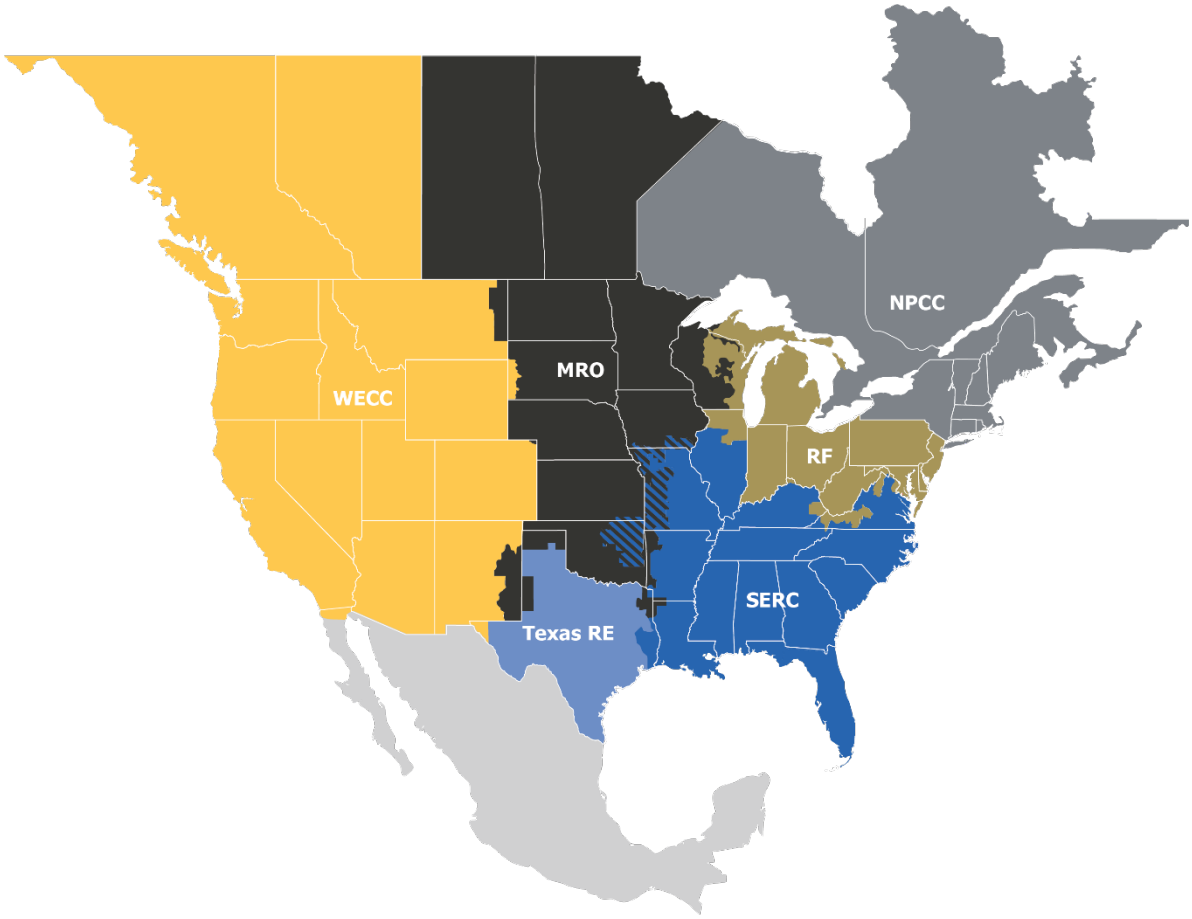
Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY
POWERING TODAY. PROTECTING TOMORROW.

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Purpose

This sensitivity case analysis of the *2025 Long-Term Reliability Assessment* (*2025 LTRA*) provides industry, regulators, and policymakers with insights on the effect that recent resource additions, approved under Midcontinent Independent System Operator's (MISO) Expedited Resource Addition Study (ERAS) process, may have on the resource adequacy projections reported in the LTRA. The analysis is prepared by NERC and applicable Regional Entities in the Eastern Interconnection[1] from MISO data and input. Results include a probabilistic analysis performed by MISO after the publication of the *2025 LTRA*. NERC initiated this limited-scope, out-of-cycle analysis in response to federal regulator feedback to provide an independent analysis into the potential effect of the substantive initiatives and regulatory actions taken in 2025 to address mounting resource adequacy concerns in the MISO area. Though this sensitivity case analysis is based on the addition of recent MISO ERAS projects, the findings and recommendations are applicable to resource planners and market operators as they confront the resource adequacy challenges described in the *2025 LTRA*.

[1] Regional Entities involved in reviewing this report are Midwest Reliability Organization (MRO), ReliabilityFirst (RF), and SERC Reliability Corporation (SERC).

Chapter 1: Summary Findings

The limited-scope sensitivity analysis confirmed *2025 LTRA* findings: Timely implementation of ERAS resources would eliminate reserve margin shortfalls in MISO and improve expected unserved energy metrics. Based on MISO's updated probabilistic analysis, the MISO assessment area was found to remain at **elevated risk** to system reliability for the 2027 year and fall to **normal risk** for the 2028–2030 period with the on-time addition of all ERAS projects (see **Table 1.1**). Furthermore, the probabilistic analysis shows that the risk of load loss and unserved energy in 2027 is reduced with the addition and operation of these projects. The results are discussed in **Chapter 3**.

Table 1.1: MISO Capacity and Energy Risk Summary

2025 LTRA					2025 LTRA with MISO ERAS Additions				
Risk Level (High, Elevated, or Normal)					Risk Level (High, Elevated, or Normal)				
2026	2027	2028	2029	2030	2026	2027	2028	2029	2030

The foundational assumption to this analysis is that all the ERAS projects and other approved resource additions from the *2025 LTRA* will be commercially operational in MISO as currently projected by the end of 2028. Such a rapid expansion, amounting to the addition of 50 GW in accredited capacity in under 3 years, will require overcoming obstacles to development that increasingly cause project delays and cancellations in MISO and other areas. Already, two battery projects with a combined 650 MW in capacity that were included in this sensitivity case have withdrawn. Project development and timing, transmission development, and natural gas fuel issues can all affect the future capacity and energy outlook. Their potential impacts on this sensitivity analysis case are discussed in **Chapter 4**.

The ERAS process developed by MISO and approved by the Federal Energy Regulatory Commission (FERC) in July 2025 is a strong initiative to shorten the timeline for generator interconnection study and approvals and help speed resources to the grid in response to mounting resource adequacy challenges identified by MISO, its member states, and the ERO.[2] Faster processing for new generators is critical to meeting demand growth, but other factors are also contributing to slower-than-anticipated BPS resource growth, including energy infrastructure needs, supply chain delays, and siting and permitting difficulties. Consistent with findings in the *2025 LTRA*, NERC continues to recommend that Independent System Operator/Regional Transmission Organizations (ISO/RTO) and stakeholders in market areas maintain necessary flexibility in their resource plans and market procurement processes. NERC's recommendations from this sensitivity case analysis are discussed in **Chapter 5.**

NERC initiated the next annual LTRA cycle in February 2026 and is planning to publish its LTRA report in early 2027. The annual LTRA covers the entire North American BPS and is based on the latest BPS resource, demand, and transmission development projections. The MISO ERAS units with their updated statuses will be reflected in the *2026 LTRA*.

[2] The ERAS process aims to respond to generation needs and provide a framework for an accelerated study of generation projects that address urgent resource adequacy and reliability needs. MISO requires that ERAS projects be accompanied by a written verification of reliability need from the Relevant Electric Retail Rate Authority (RERRA), or a documented representative, where the load to be served by the generating facility is located.

Chapter 2: Sensitivity Analysis Scope and Approach

This sensitivity case analysis provides insights into the potential effect that the ERAS process resources may have on resource adequacy in the MISO assessment area if they are able to meet all commercialization targets. Changes to the analysis are limited to the inclusion of the ERAS resources, which were not included in the *2025 LTRA*. Load forecasts and other resource projections were not updated in the probabilistic analysis conducted by MISO.

Analysis Approach

NERC evaluates industry-provided resource adequacy data and credible studies to assess risks of future energy shortfalls as the system is currently planned. Probabilistic and deterministic analyses provide forward-looking snapshots of resource adequacy tied to industry forecasts of electricity supplies, demand, and transmission development. The risk analysis entails these components:

- **Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability across all hours:** This approach identifies high-risk periods and potential energy constraints resulting in load-loss events. MISO updated the 2025 Probabilistic Assessment (ProbA) to examine the system as planned for the years 2027 and 2029. Loss-of-load hours (LOLH) and expected normalized unserved energy (NEUE) from the probabilistic analysis were used to identify risk levels.
- **Comparing the margin between projected resources and peak net demand, or Anticipated Reserve Margin (ARM), to a reserve margin target:** This reserve margin target is known as the Reference Margin Level (RML), and it represents the accepted level of risk based on a probability-based loss-of-load analysis.

The risk determination is based on data and information provided to NERC and represents a snapshot in time.

Risk Categories

NERC uses the following three levels of risk category determination for each assessment area and associated years for which there is a risk of energy shortfall during the first five years of the LTRA period. An assessment area is determined as **High Risk** when established resource adequacy targets or requirements are not met or when probabilistic or deterministic energy analyses find that planned resources produce shortfalls resulting in unserved energy or load loss exceeding criteria for the baseline resource adequacy specified as follows:

- Annual LOLH exceeds 2 hours/year for one or more years in the ProbA.
- Annual normalized expected unserved energy (EUE) exceeds 0.002% (20 ppm) for one or more years in the ProbA.
- Resource adequacy target(s) established by the regulatory authority or system operator are not met.

An assessment area is determined to have **Elevated Risk** when it meets the established resource adequacy targets and baseline criteria but does not meet more stringent thresholds of unserved energy and load loss that provide for reliability in more extreme weather conditions.

- Annual LOLH is between 0.1 and 2 hours/year for one or more years in the ProbA.
- Annual normalized EUE is less than 0.002% (20 ppm) but greater than or equal to 0.0002% (2 ppm) for one or more years in the ProbA.

- Resource adequacy target(s) established by the regulatory authority or system operator are met but plausible scenarios of above-normal demand and/or low-resource conditions indicate risk of load loss.

An assessment area is determined to have **Normal Risk** if resource adequacy criteria are met and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low.

- Annual LOLH is below 0.1 hours/year in the ProbA.
- Annual normalized EUE is below 0.0002% (2 ppm).
- Resource adequacy target(s) established by regulatory authority or system operator are met and reserves are expected to be available in plausible scenarios of above-normal demand and/or low-resource conditions associated with a once-per-decade event.

Chapter 3: Capacity and Energy Risk Analysis for MISO with ERAS

The probabilistic analysis done in March 2026 for this sensitivity case found that the MISO assessment area had improved resource adequacy metrics compared to the *2025 LTRA*. With ERAS additions, MISO would be in the **elevated risk** category for year 2027. From 2028 and beyond, the risk threshold has shifted to **normal risk** with the addition of ERAS projects and the assumption that these will become commercially operational by the end of 2028 (see **Table 3.1**).

Table 3.1: Capacity and Energy Risk Numerical Summary for MISO with ERAS

Year	EUE (MWh)	NEUE (ppm)	LOLH (hours per year)	Anticipated Reserve Margin (ARM)		Reference Margin	
				Summer	Winter	Summer	Winter
2026				11.8%	27.2%	8.1%	19.1%
2027	430.62	0.61	0.11	12.5%	26.0%	8.3%	19.8%
2028				19.5%	37.1%	8.5%	20.5%
2029	0.00	0.00	0.00	28.5%	31.8%	8.5%	20.9%
2030				24.0%	27.0%	8.5%	21.2%

Most of the MISO ERAS resource capacity is projected to come from natural-gas-fired generators, which are generally dispatchable and help reduce energy shortfall risks throughout the year. When analyzing results from the updated probabilistic analysis, risk of load loss was seen to remain in 2027 and resided within the summer season, while risk of load loss within the winter season was mitigated. Both the 2027 and 2029 updated results displayed an overall reduction in the annual unserved energy metrics compared to the *2025 LTRA* results.

Figure 3.1 details the capacity additions that were included within each season and year of this analysis.[3]

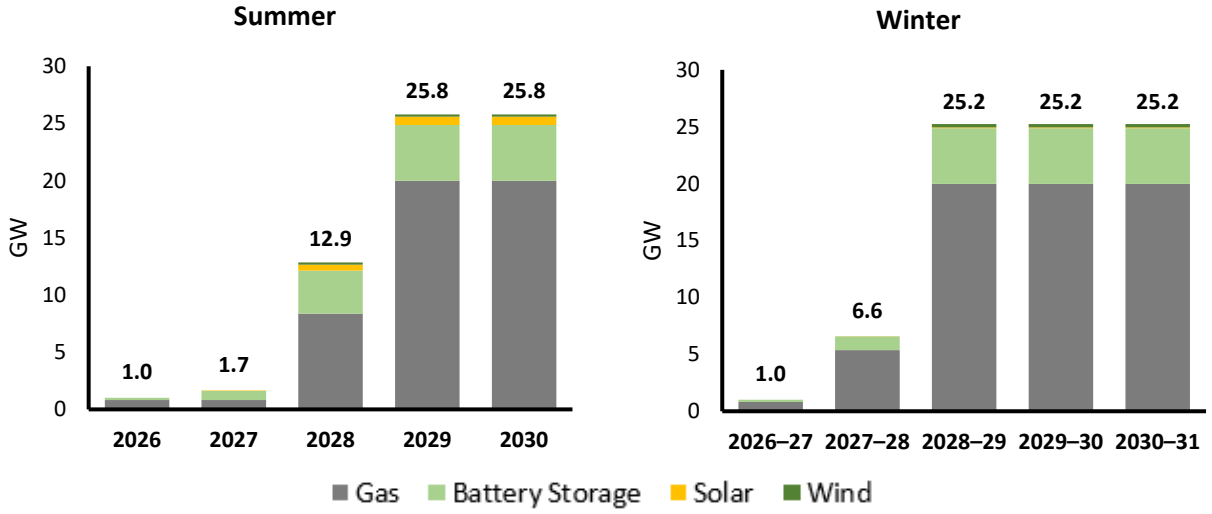


Figure 3.1: ERAS Project Cumulative Capacity Addition Summary 2026–2030[3]

[3] Values are unforced capacity (or certain capacity) additions as reported by MISO. In general, unforced capacity refers to the expected capability of the resource to provide energy to serve expected demand. Thermal generating capacity is adjusted to account for outages or derates. Solar, wind, and batteries are derated due to their variability.

Analysis of anticipated resources (existing + Tier 1) when compared with 2025 load forecast projections display adequate capacity for both the summer and winter seasons and may be seen in **Figure 3.2**. These results offer a point-in-time snapshot of risk based on the data available during the time of this analysis and provide additional insights from a deterministic approach.

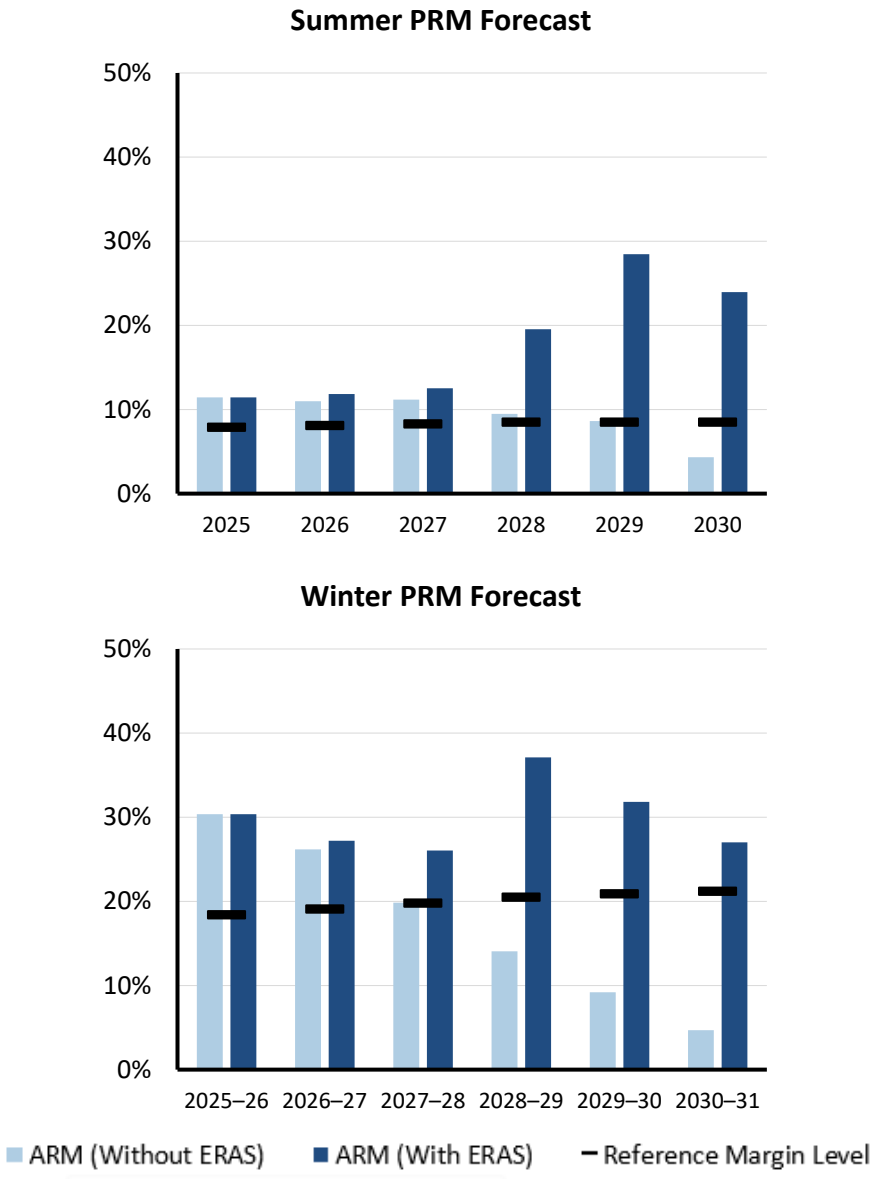


Figure 3.2: MISO Planning Reserve Margins with and Without ERAS Additions

The foundational assumption to this analysis is that all the ERAS projects will be commercially operational as currently projected by the end of 2028. The included ERAS resources meet the criteria that NERC uses for counting capacity in the LTRA energy and capacity risk assessment, but the pace of resource additions in MISO with ERAS far exceeds recent historical levels. In the *2025 LTRA* and 2025 ProbA MISO factored in potential delays and withdrawals to resource additions based on historical information from the interconnection process. The following chapter discusses project timing and completion concerns and other issues that would affect the capacity and energy risk results presented in this chapter.

Chapter 4: Grounded Expectations

The ERAS process can enable rapid interconnection study and approvals, but industry still faces persistent headwinds to develop energy infrastructure. Familiar obstacles to realizing the speed and scale of resource additions in MISO remain, including development of the transmission network and fuel infrastructure needed to support the new generation. MISO, utilities, and regulators will need to carefully monitor the ERAS and interconnection queue progress, development of related transmission and energy infrastructure, and load forecast projections. Areas of concern are highlighted in this chapter.

Realistic Projections for Resource Additions

The approval of new ERAS projects in late 2025 provides a sizable increase to the projected resource additions in MISO at a time when MISO and other areas are straining to build out new generation and transmission. MISO is projecting strong growth in resources—exceeding 50 GW of accredited capacity by 2029 Summer (50% from ERAS projects)—to meet growing demand (see **Figure 4.1**). In the next three years alone, MISO is projecting to add over 34 GW of accredited capacity to its system, which is three times more accredited capacity than has come on-line in the last three years within the MISO area. For such an acceleration in resource development, challenges should be anticipated.

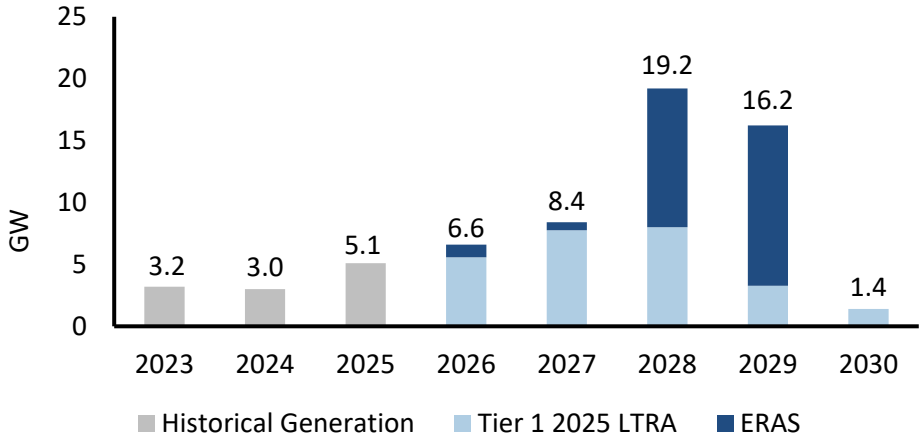


Figure 4.1: Historical and Projected Accredited Capacity Additions in MISO[4]

Over the past two years, NERC's LTRA has shown that industry resource growth projections can outpace actual completion rates. Industry efforts to interconnect new resources and develop energy infrastructure are hampered by unresponsive supply chains, permitting delays, and project owner decisions that contribute to an uncertain pace of resource growth. Reviews of interconnection progress find that many resources do not come in as expected. Analysis performed by WECC for the Western Interconnection found that, on average from 2022 to 2024, 67% of the planned resources in the West were added on time.[5] Lawrence Berkeley National Labs analysis finds that the median time for generators to go from having a signed interconnection agreement to commercial operation is 33 months and has been growing.[6]

[4] Historical accredited generation came on-line by the end of the calendar year while projected capacity is assumed to be on-line by the summer season of the year referenced.
Historical accredited generation came online by the end of the calendar year while projected capacity is assumed to be online by the summer season of the year referenced.
[5] WECC 2025 Western Assessment of Resource Adequacy
[6] Lawrence Berkeley National Laboratory Queued Up 2025 Edition

Risk of Project Delays

ERAS projects have priority for study and processing stages of interconnection but are not insulated from other project development hurdles, like slow supply chains or issues with siting and permitting. ERAS generator projects may also require transmission or natural gas infrastructure upgrades that can also be subject to the same development challenges. Equipment delays and shortages in materials and skilled workers are affecting generator and transmission projects broadly. The industry is experiencing delays due to low availability of long-lead equipment including gas turbines and power transformers, and issues are expected to become more acute as demand for grid equipment escalates globally.[7] Permitting challenges are also on the rise. It is increasingly common for new generation and energy infrastructure projects to face opposition at local government levels, though some states in MISO now prohibit local laws from being more restrictive than state laws for some resource types.[8]

MISO interconnection queue timelines for past (non-ERAS) projects indicate that delays can reach one and a half years for natural gas resources, two years for battery storage resources, and over two and a half years for wind and solar resources from the completion dates in original interconnection agreements. The ERAS process allows project developers to delay their commercial operation date (COD) by up to three years from the COD on its approved interconnection agreement.

Risk of Project Cancellations

System planners can anticipate that some resource project developers will cancel their projects despite the expedited interconnection processing. The Texas Energy Fund (TEF) is an example of an initiative to spur resource growth in Texas that is underutilized and suffered from 5 GW in project withdrawals since it was established in 2023. The TEF program currently has 3.5 GW in approved projects and has produced few resource additions toward the program's goal of 10 GW.[9]

MISO's ERAS program carries penalties for project owners that cancel their project after receiving a signed interconnection agreement. Projects totaling 5.3 GW of installed capacity (18% of current ERAS projects) have executed interconnection agreements. Projects can be withdrawn from the ERAS queue prior to having an interconnection agreement without penalty. As of March 2026, 36 GW of projects entered the ERAS queue and 18% of that total (or 6.6 GW) have been withdrawn from the ERAS queue (see **Figure 4.2**). Two of the withdrawn projects are battery resources with a combined 650 MW capacity that were included as additions in this sensitivity analysis.

[7] WECC reports in the 2025 Western Assessment of Resource Adequacy that wait times for transformers and circuit breakers is between two and four years.

[8] Matthew Eisenson, Jacob Elkin, Ivonne Norman, Rebecca Coombs, Chadol Kim, Rex Koenig, Suzan Michalski, Eric Quiroz, Josepi Scariano, Ava Teasdale, Victor Tong, and Annabel Williams, Opposition to Renewable Energy Facilities in the United States: June 2025 Edition, Sabin Center for Climate Change Law, June 2025 Available at: https://scholarship.law.columbia.edu/sabin_climate_change/251

[9] See Texas Energy Fund online for listing of awards and links to filings.

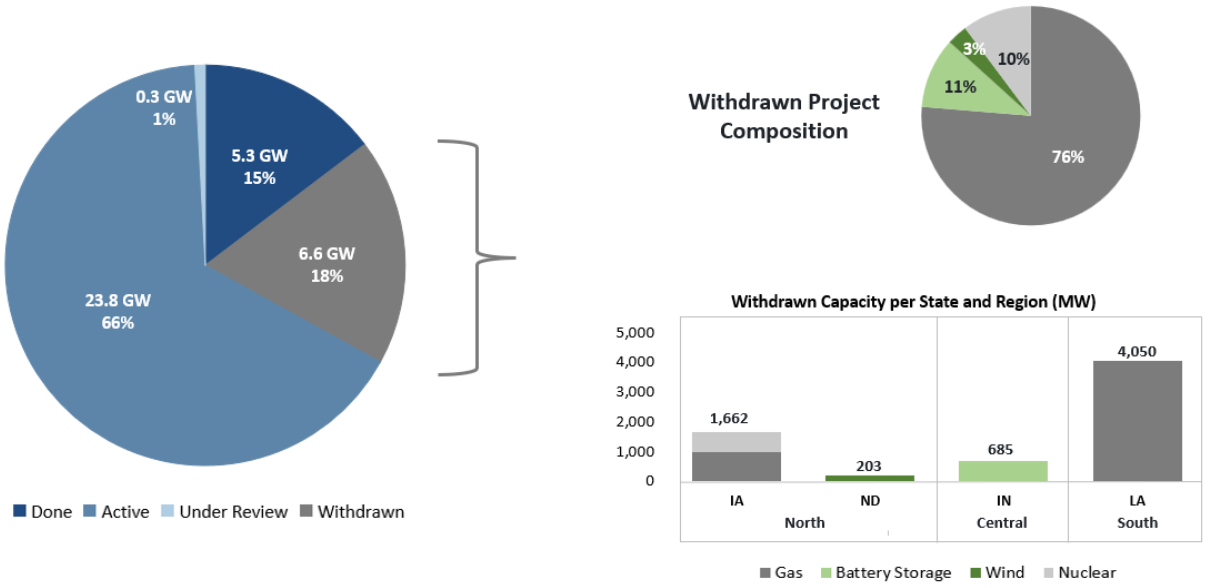


Figure 4.2: Total ERAS Project Summary and Withdrawn Composition (Max Installed Capacity)

Trends in Load Forecasts are Rising

In updating resource projections with late 2025 additions but not including the new load forecasts that MISO is processing for this same point in time, the limited-scope analysis ignores the effect that past trends in load growth could have on the results. NERC's *2025 LTRA* observed that BPS electricity demand forecasts continue to rise over prior-year assessments. In 2025, MISO reported higher demand forecasts than the prior year and expected that increases would continue.

As noted in the *2025 LTRA*, MISO's forecasted peak total internal demand is expected to reach 127 GW during the 2026 Summer season (up over 2.6 GW since the same year's projection in the *2024 LTRA*) and is expected to grow to 143.7 GW by 2035. Much of MISO's load growth forecast comes from the addition of large computational loads whose operational characteristics are still being evaluated to better understand the impact that these loads will have during low margin or critical hours where system risk may occur. Over the past several years, load forecasts have changed year over year to include higher peak demands with varying expectations for when these loads will materialize across the MISO system. All assessment areas, including MISO, will provide new load forecast projections for the *2026 LTRA* in July 2026.

Natural Gas Infrastructure Needs

The addition of ERAS natural-gas-fired generation in the next four years can provide important reliability benefits provided that the fuel infrastructure can support MISO's growing reliance on natural gas fuel. However, the current natural gas system can become constrained during extreme cold weather resulting in operational flow orders and fuel supply curtailments to electric generators.[10]

Over 75% (exceeding 20 GW) of ERAS projects in this analysis are natural-gas-supplied and are concentrated in Louisiana, Indiana, Wisconsin, and Iowa. The ability of current natural gas transportation capacity to meet increasing generation needs is in question, and newly planned natural gas infrastructure is at risk of delays

[10] Winter storms Uri in 2021 and Elliott in 2022 revealed vulnerabilities within the interdependent natural gas and electric systems through major gas supply disruptions. More recently, MISO noted generator unplanned outages and derates due to fuel related issues in Winter Storm Fern.

due to regulatory and commercial challenges, as well as supply chain congestion. In addition, there is potential for misalignment between the locations of new pipeline projects and the areas of greatest need. The stress on the natural gas pipeline grid makes clear the need for careful analysis of generator fuel assurance plans and backup fuel capability.

Chapter 5: Recommendations

The limited-scope analysis confirmed *2025 LTRA* findings: Timely implementation of ERAS resources would eliminate reserve margin shortfalls in MISO and improve EUE metrics. This is a significant and important takeaway. By streamlining the study and interconnection process for resource additions that address identified reliability needs and are approved by regulators, MISO is removing an obstacle that has become increasingly prevalent in the ISO/RTO areas. The ERAS program is a strong response by MISO, its utility members, and state regulators to address serious resource adequacy challenges from load growth, generator retirements, and a transforming resource mix. **As MISO and other ISO/RTOs analyze their interconnection queue performance, NERC recommends that they share findings and best practices to promote broad application of enhancements that reduce backlogs in interconnection queues and support adding resources that are needed for reliability.**

As more ERAS projects reach the stage of having signed interconnection agreements and begin siting, permitting, and construction, it is crucial for MISO, Generator Owners, and regulators to carefully track their progress and be prepared to adjust resource and system plans. Industry has reported delays for energy infrastructure projects that stem from a variety of sources.

NERC recommends that ISO/RTOs and stakeholders in market areas maintain necessary flexibility in their resource plans and market procurement processes. Monitoring the development of projects in the expedited interconnection processes and feedback loops are needed so that adjustments can be made when resource buildout is not on track to meet intended targets. Factors that can affect resource development timelines that need to be monitored include the following:

- **Siting and permitting:** Project developers should provide early indication of permitting challenges to regulators and ISO/RTOs.
- **Supply chain issues:** An up-to-date project status will help maintain a realistic outlook for commercial operation.
- **Fuel infrastructure development:** To support substantial additions in natural-gas-fired generation and accurately assess their contribution to reliability, system planners need to have insights into fuel arrangements and should monitor natural gas industry plans for infrastructure development.
- **Project cancellations:** Stakeholders in expedited interconnection processes should maintain flexibility in resource plans while project owner plans progress toward commercial operation.

Planners will need to balance the pace of resource additions against future shifts in demand forecasts. Escalating load forecasts have been the trend for the North American BPS for the past three years with several areas expecting peak demand to grow by over 2% per year for the next 10 years. Because of the size and construction speed of new data center projects, demand forecasts can change substantially each year. Expedited resource programs such as ERAS are providing a crucial boost to meet needs as anticipated today; however, flexibility in resource plans and interconnection processes will still be needed to meet shifting demand forecasts and development timelines.

NERC's *2026 LTRA* will provide a more complete snapshot of future resource adequacy risks for MISO and the rest of the North American BPS. The next LTRA will be published in early 2027.

MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

Capacity Demonstration Results

Planning Year 2029/30

Case No. U-21907

May 12, 2026

MPSC Staff

LARA
LICENSING AND REGULATORY AFFAIRS

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Executive Summary

All Michigan load serving entities (LSE) required to file capacity demonstrations with the Michigan Public Service Commission (MPSC or Commission) for planning year 2029/30, pursuant to MCL 460.6w and the August 21, 2025 Commission Order in Case No. U-21907, have filed. MPSC Staff (Staff) has audited the filings, contracts, and other materials and finds that all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year (PY) 2029/30.

Staff projects that the Midcontinent Independent System Operator, Inc. (MISO) Local Resource Zone (LRZ) 7, which consists of Michigan's lower peninsula and excludes the southwest corner of the state located in Indiana Michigan Power Company's (I&M) service territory, will have sufficient resources to meet its planning reserve margin requirements (PRMR) and local clearing requirements (LCR) in all four seasons for the compliance year (2029/30).[1] For MISO LRZ 1 and LRZ 2, the majority of which are in other states not subject to MCL 460.6w, Staff does not have sufficient detail to project the capacity positions of these zones. Staff projects that the I&M service territory in Michigan will have sufficient capacity to meet PJM Interconnection LLC's (PJM's) requirements for the prompt and compliance years.

The most recent Organization of MISO States (OMS)-MISO Resource Adequacy Survey (OMS-MISO Survey) of 2025,[2] which serves as a point-in-time analysis based on data collected during April 2025, provides a resource adequacy view over a five-year period (PY 2026/27 through PY 30/31). This year, the survey results separated potential new capacity from replacement/surplus capacity in the resource adequacy projections. For the Summer season, projections of potential new capacity, based off 3-year historical projections, increased to 3.5 GW/year from 2.3 GW/year in 2024. This was largely due to the exclusion of 2021, which had significantly lower build rates than surrounding years. The survey results project that MISO will have a 6.4 GW deficit to 10.5 GW surplus by Summer 2029, depending on the amount of potential new and replacement/surplus capacity that is able to be added each year. For the Winter season, the historical projections have decreased from 3.5 GW/year to 1.4 GW/year due to heavy reliance on solar additions, which have very low accreditation in winter (5% vs 50% accreditation in summer). The survey results project that MISO will have a 15.1 GW deficit to a 0.5 GW surplus by winter 2029/30. Fall ranges from a 2.5 GW deficit to a 14.6 GW surplus by fall 2029. Spring ranges from a 3.5 GW deficit to a 13.6 GW surplus. In addition, projections for each subregion in Summer and Winter were published, showing the North/Central subregion ranging from a 2.5 GW deficit to an 8.5 GW

[1] This projection is based on the filed capacity demonstrations and information from MISO available at the time of this report and is dependent on several variables including but not limited to: load growth, delays in completion of planned resources, and changes to MISO's resource adequacy construct.

[2] 2025 OMS-MISO Survey Results published June 6, 2025.

surplus in Summer 2029 and a 7 GW deficit to a 2.6 GW surplus in Winter 2029/30. The OMS-MISO Survey no longer projects future capacity positions for individual LRZs; however, the survey does show individual LRZ's potential to meet their LCR in each season of the prompt year. Both LRZ 1 and 2 show sufficient capacity to meet obligations in Planning Year 2025/26. New OMS-MISO Survey results for 2026 will be released June 4, 2026.

MISO's 2026/27 Planning Resource Auction (PRA) results indicated sufficient capacity at the regional, subregional, and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance. System-wide surplus (above the target Planning Reserve Margin or PRM) offered into the auction was 2.0 GW higher compared to last summer, even with a 2.7 GW increase in required capacity (Initial PRMR). The system-wide surplus capacity in the summer has increased from 2.6 GW in 2025 to 4.6 GW in 2026.

MISO noted in its 2026 PRA Results[3] that capacity offered into this year's auction has increased by as much as 4% in some seasons over last year. New capacity additions and more imports outweighed lower accreditation and retirements/suspensions, and MISO states that capacity additions need to continue to increase, given the expected demand growth from new large loads. MISO continues to reform its resource adequacy construct under the Reliability Imperative to address emerging risks due to fleet transition, new load additions, and retirements of dispatchable units.

[3] MISO 2026/27 PRA Auction Results

Background

On September 15, 2017, in Case No. U-18197, the Commission directed all Michigan LSEs to file capacity demonstrations annually, pursuant to MCL 460.6w. This report outlines the results of the capacity demonstrations filed for PY 2029/30, as directed by the Commission in Case No. U-21907, and represents the ninth annual capacity demonstration report. Prior year capacity demonstration reports can be found in the following dockets:

- 2021/22: Case No. U-18441
- 2022/23: Case No. U-20154
- 2023/24: Case No. U-20590
- 2024/25: Case No. U-20886
- 2025/26: Case No. U-21099
- 2026/27: Case No. U-21225
- 2027/28: Case No. U-21393
- 2028/29: Case No. U-21775

In Case No. U-21907, for the 2029/30 planning year, the Commission ordered[4] investor-owned utilities with one million or more customers[5] to file capacity demonstrations by February 24, 2026, investor-owned utilities with less than one million customers[6] to file by March 3, 2026, and alternative electric suppliers (AESs),[7] cooperatives (co-ops), and municipal utilities to file on or before March 17, 2026.

The purpose of these capacity demonstrations is to ensure that each electric utility owns or has contractual rights to capacity sufficient to meet its capacity obligations as set by the MISO, PJM, or the Commission, as required by MCL 460.6w.

Pre-Demonstration Process

As with previous years, Staff offered LSEs the opportunity to meet with Staff to discuss the capacity demonstration requirements and review relevant materials prior to the

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[4] August 21, 2025 Order in Case No. U-21907.

[5] Consumers Energy Company, DTE Electric Company.

[6] Alpena Power Company, Indiana Michigan Power Company, Northern States Power Company-Wisconsin, Upper Michigan Energy Resources Corporation, and Upper Peninsula Power Company.

[7] AEP Energy Inc; American Rural Cooperative; BP Energy Retail Company, LLC; Calpine Energy Solutions LLC f/k/a Noble Americas Energy Solutions LLC; CMS ERM Michigan LLC; Constellation NewEnergy Inc; Dillon Power LLC; Direct Energy Services LLC; Energy Harbor LLC; Energy International Power Marketing Corporation; Energy Services Providers Inc.; Interstate Gas Supply LLC; Just Energy Solutions Inc; MidAmerican Energy Services LLC; Nordic Energy Services LLC; NRG Energy Inc. f/k/a Direct Energy Business, Texas Retail Energy; LLC, U.P. Power Marketing LLC; and Wolverine Power Marketing Cooperative Inc.

final filing deadlines. Several LSEs met with Staff remotely and clarified the process before filing reports in the docket. Staff found that the pre-filing consultations were helpful in resolving questions prior to filing. Staff will continue to offer pre-filing consultations each year to resolve potential issues prior to the filing deadlines.

Capacity Demonstration Filings

On or before February 24, 2026, capacity demonstration filings were received from DTE Electric Company and Consumers Energy Company. On or before March 3, 2026, capacity demonstration filings were received from Alpena Power Company, Indiana Michigan Power Company, Northern States Power Company, Upper Michigan Energy Resources Corporation (UMERC), and Upper Peninsula Power Company (UPPCO). Many LSEs filed confidential information under seal as part of the electric utilities' filings. Staff reviewed this information and met with LSEs as needed.

On or before March 17, 2026, capacity demonstration filings were received from American Rural Cooperative; Bayfield Electric; Calpine Energy Solutions, LLC.; City of Escanaba; City of Stephenson; City of Wakefield; Cloverland Electric Cooperative; CMS ERM; Constellation New Energy Inc.; Croswell Light and Power; Daggett Electric Department; NRG Energy f/k/a Direct Energy Business, LLC; Energy Harbor; Michigan Public Power Agency; Michigan South Central Power Agency (MSCPA); Newberry Water and Light Board; Union City Electric Department; Wolverine Power Supply Cooperative; and WPPI Energy.

Several AESs filed letters in Case No. U-21907 indicating that they are currently not serving customers in Michigan.[8]

All LSEs were able to procure the necessary capacity to demonstrate compliance for the current planning year in all four seasons. Staff conducted an audit for each capacity demonstration filing received and requested additional information from the LSEs when necessary. Staff has reviewed all contracts included in capacity demonstrations from AESs, as well as most of the contracts from co-ops, electric utilities, and municipalities. In addition to the required compliance year (PY 2029/30), most capacity demonstrations included updates for the 2026/27 planning year through the 2029/30 planning year. [9]

During this year's capacity demonstration, Alpena Power presented an alternative interpretation of the 5% limit on PRA acquisitions in the demonstration year. As shown

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[8] AEP Energy Inc.; BP Energy Retail Company, LLC; Dillion Power LLC; Direct Energy Services LLC; Energy Services Providers, Inc.; Interstate Gas Supply LLC; Just Energy; Energy International Power Marketing; MidAmerican Energy Services LLC; Nordic Energy Services LLC; Texas Retail Energy, LLC; and UP Power Marketing.

[9] The required demonstrations for planning years 2027/2028 and 2028/29 were made in the 2024 capacity demonstration (Case No. U-21393) and the 2025 capacity demonstration (Case No. U-21775).

in the chart below, the planned capacity from the PRA for the Summer season is over 5% (8.3%) and the remaining seasons under 5%, so that the annual average or % of total requirements for the year was below 5% when adding all seasons together. Since the implementation of MISO's seasonal construct into the state capacity demonstration process, Staff has always interpreted the 5% limit for planned PRA purchases as 5% of each season's requirements (Initial PRMR). However, there is no specific language in the process and requirements document or the statute itself specifying that the 5% limit applies to each season individually. Staff recommends the Commission clarify the 5% limit on resources acquired from the PRA in the demonstration year to be a limit on total annual requirement or each seasonal requirement and direct Alpena to action if necessary.

	Capacity from PRA	PRMR (requirement)	%
Summer	5	60	8.33%
Fall	0	52	0%
Winter	0	48	0%
Spring	1	50	2.0%
Total	**6**	**210**	**2.9%**

The Order opening the docket in U-21907 directed all entities to file data for the prompt and interim years, as well as the compliance year. Most entities complied but some of the small municipal utilities continued to only provide information for the compliance year (PY 2029/30). For these entities, Staff was able to estimate the amount of capacity available for the prompt year and interim years by projecting the amount included for PY 2029/30 backwards for three years.

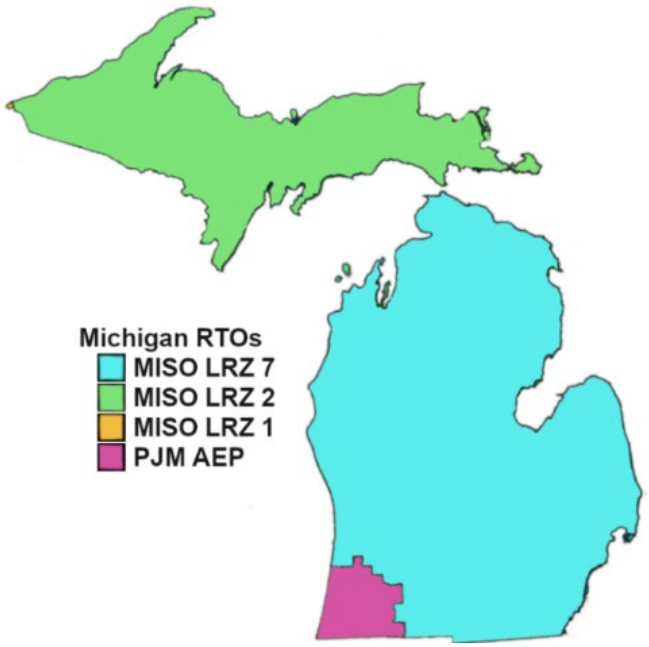
Staff recommends the Commission continue to direct all LSEs to include updated prompt year and interim year capacity obligation and resource information in future filings. Staff uses this information to help track changes in load and resources and to project the zonal resource adequacy more closely in these years. In addition, Staff recommends the Commission direct LSEs to provide MISO Module E Capacity Tracking (MECT) screenshots of their load obligations (PRMR/Peak Load Contribution (PLC)) to facilitate the Storage Target calculation used to comply with Public Act 235.[10]

[10] See January 23, 2025 Order in Case No. U-21571.

Overview of Zonal Adequacy

Michigan contains load that spans two regional transmission operators (RTOs): MISO and PJM. The majority of Michigan's load is located within MISO and is split between several LRZs. The exception is the Southwest corner of the Lower Peninsula, which is located within the PJM RTO through I&M's service territory. PJM and MISO have different resource adequacy constructs and capacity obligations. The different RTO regions in Michigan are illustrated in Figure 1.

Figure 1: RTO Zonal Regions in Michigan



MISO Resource Adequacy

Michigan LSEs serve load in MISO Local Resource Zones 1, 2, and 7. MISO's capacity construct is for the upcoming year (prompt year) only. LSEs must demonstrate sufficient resources to meet their current prompt year requirement four years forward to comply with MCL 460.6w.

MISO establishes capacity obligations for all LSEs based on peak load forecasts and a planning reserve margin percentage (PRM) necessary to meet the North American Electric Reliability Corporation's (NERC) Loss of Load Expectation (LOLE) standard of 1 day in 10 years. LSEs within MISO can meet their capacity requirements either through a Fixed Resource Adequacy Plan (FRAP), self-schedule, Reliability Based Demand Curve (RBDC) opt-out, paying the capacity deficiency charge, or through the Planning Resource Auction (PRA). The PRA is a residual market for LSEs that choose not to utilize other participation options or do not have enough capacity resources, either owned or purchased bilaterally, to satisfy their capacity obligations and, thus, need to purchase additional resources.

Within MISO's resource adequacy construct, the Planning Reserve Margin Requirement (PRMR) and the Local Clearing Requirement (LCR) must be satisfied to meet the LOLE standard. The Initial PRMR is determined through LOLE modeling, based on the coincident MISO peak forecast, and resources adjusted as necessary to meet the standard. PRMR resources are not location specific, i.e. they can come from outside an LSE's zone. Individual LSEs are responsible for their own share of the zone's PRMR. The ability to use imports to meet PRMR makes it likely all zones will meet this requirement. Failure to meet PRMR would only occur if there were not enough resources available within all of MISO's footprint or in the subregion (MISO North/Central or MISO South) given subregional transmission constraints.

The LCR is the minimum capacity required to be located within the zone to meet the LOLE standard, while accounting for the LRZ's ability to import. The LCR is for the entire zone, collectively, and not a requirement for individual LSEs; there is currently no LCR requirement applicable to individual LSEs in Michigan, pursuant to MCL 460.6w. The LCR is determined by performing a LOLE analysis on each zone, individually, to determine the Local Reliability Requirement (LRR) or the resources a zone would need to meet the loss-of-load standard if it were separated from MISO. Separately, MISO determines the import and export limits for each zone by performing a seasonal transfer analysis study. The study produces Zonal Import Ability (ZIA) and Zonal Export Ability (ZEA) values, which are then adjusted by the amount of controllable exports to non-MISO load to determine Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The ZIA is an input to the LCR calculation, and the LCR, CEL and CIL, and subregional constraints are inputs to the PRA clearing process.

In PY 2023/24, MISO implemented a seasonal resource adequacy requirement for each summer, fall, winter, and spring season and a seasonal accredited capacity (SAC) methodology for certain resources participating in MISO's PRA to align with real time

availability and planned outages. Staff reviewed these changes with participants in its 2022 and 2023 technical conferences as a part of the Commission's June 22, 2022 Order in U-21099, and results of these activities included requiring entities to file capacity demonstrations showing resources to meet obligations in all four seasons, modifications to the filing timeline, and adoption of ISO-neutral language into the process and requirements. Commencing PY 2024/25, the Commission's July 26, 2023 Order in U-21393 directed LSEs in MISO to demonstrate seasonal capacity obligations based on the MISO seasonal resource adequacy construct. LSEs are obligated to demonstrate enough capacity (owned or contracted) to meet that LSE's capacity obligation for each season.

In PY 2025/26, MISO's Reliability Based Demand Curve (RBDC) tariff revision implemented sloped demand curves into the PRA. The August 21, 2025 Order opening the docket in U-21907 directed LSEs to meet *Initial* Planning Reserve Margin Requirements for the capacity demonstration to clarify requirements after implementation of the sloped demand curves. The specific capacity obligation for each season will be the LSE's prompt year (upcoming year) Initial Planning Reserve Margin Requirement for each respective season.

Under the MISO resource adequacy construct, if an LRZ does not have sufficient resources to meet its seasonal requirements, the entire LRZ clears at the LRZ's seasonal Cost of New Entry (CONE) value. CONE varies from zone to zone and changes from year to year but, for reference, for 2026/27 the Annual CONE is $137,510/MW-year ($376.73/MW-day) in Zone 7.[11] The PRA clearing price being set at CONE would have economic ramifications and should provide a signal to entities with responsibilities regarding resource adequacy within the zone. However, it is important to note that MISO's resource adequacy construct is based on probabilistic determinations and failure to meet the requirements of the resource adequacy construct would not mean that the LRZ in question will experience a loss of load event. It simply means that the probability of such a loss of load event would exceed the generally accepted criteria that govern the resource adequacy planning process.

Details on MISO's Demand Response Tariff Revisions

MISO has recently filed or is currently working on Federal Energy Regulatory Commission (FERC) filings to address issues and challenges related to demand side resources, including Demand Response Participation Rules Enhancements, Elimination of Dual Registration, and Demand Response and Emergency Resource (DR/ER) reforms (formerly known as Load Modifying Resource or LMR reforms).

The demand response tariff revisions filed at FERC in 2025 include:

- ER25-1729 filed in March, which seeks to discourage nonexistent or overstated curtailments by requiring proof of contracts, as well as hourly meter data. In

[11] MISO 2026 PRA results

addition, this filing institutes reference levels for resources so that they cannot inflate their baselines. Accepted by FERC July 2025.

- ER25-2050 filed in April, which ends dual registration for load modifying resources also registered as emergency demand response. Accepted by FERC July 2025.
- ER25-2845 filed in July, requiring market participants registering demand resources to demonstrate demand reduction capability annually for each planning year. Accepted by FERC November 2025. Market participants can demonstrate demand reduction capability by:
    - Meeting MISO scheduling instructions in the prior Planning Year,
    - Conducting a Real Power Test, or
    - Submitting operational data or using an alternative mechanism to demonstrate demand reduction capability if unable to conduct a real power test or choose to waive the obligation and be subject to a higher financial penalty for non- or under-performance.
- ER25-1886 filed in April, which created fast and slow responding categories for demand resources, with faster resources receiving higher capacity accreditation, to take effect PY 2028/29. FERC deficiency letter requiring more information from MISO on the proposal's inner workings.
- ER26-148, which eliminated energy efficiency from the capacity auctions. Accepted by FERC December 2025.

LOLE Continuing Error & LOLE Definition Filing

During the 2025/26 Planning Year, MISO discovered a continuing software error in its LOLE calculations. Since the 2018/19 Planning Year, the software MISO uses in its LOLE modeling had been applying an *all hours* methodology instead of the Tariff-defined daily peak hour methodology. In instances of this type of error, the Tariff specifies a one-year look-back for financial adjustments. Adjustments were made for all four seasons of the 2025/26 Planning Year only, with over 80% of the $280 million financial impact falling in the summer season.

On August 27, 2025, MISO submitted a proposal to FERC to revise MISO's Module A Tariff definition of the term Loss of Load Expectation (ER25-3307), with an effective date of October 27, 2025. LOLE is currently defined as "the sum of the loss of Load probability for the integrated daily peak Hour for each Day of the year" and the proposal requests the definition be revised to "An estimate of the average number of days with supply interruption to end use customers, whether for a single hour or multiple hours in a day." This revision aligns the LOLE analysis with the Direct Loss-of-Load (DLOL) based methodology used to accredit resources and establish the Planning Reserve Margin MISO plans to implement in PY 2028/29.[12] This was accepted

[12] MISO Transmittal Letter in ER25-3307, pp. 3-4.

by FERC on October 24, 2025, and the all hours methodology was used in the PY 2026/27 Planning Year LOLE calculation.

Future Resource Adequacy Construct Changes

MISO aims to implement enhanced resource adequacy risk modeling and a DLOL accreditation methodology (FERC Docket ER24-1638, filed 3/28/2024) beginning in Planning Year 2028/29. MISO has committed to publishing indicative accreditation results based on the DLOL methodology prior to each Planning Resource Auction, starting with Planning Year 2025/26.[13] Two different Indicative PRM and accreditation values under DLOL were published in PY 2025/26 and another set was published in PY 2026/27. In addition, MISO's Futures reports include projected outyear accreditation values of resource classes.

The DLOL reforms will align the PRMR with accreditation of all resource classes. MISO continues its work on the PRMR allocation piece of the reforms; therefore, individual LSE's PRMR values under DLOL are not yet available. Some entities showed the impact of pending DLOL reforms in this year's filing, either voluntarily or as directed by Commission Order. The December 18, 2025 Order in Case No. U-21990 directed DTE Electric (the Company) to provide an updated analysis in its next capacity demonstration filing, showing the impact of the Customer on the Company's capacity requirements under DLOL using MISO's most recent indicative DLOL results. This separate analysis was filed alongside their standard capacity demonstration, as required by the Order. Staff recommends the Commission determine a timeline and guidelines to implement MISO's DLOL-based resource adequacy construct changes into the state capacity demonstration process, prior to MISO tariff changes effective PY 2028-29.

The compliance year (PY 2029/30) capacity obligations that are demonstrated for in this case are based off an LSE's prompt year (PY 2026/27) requirement. Changes to load, resources, and MISO procedures in the upcoming years can lead to discrepancies between an LRZ having sufficient capacity to meet its four-year forward Michigan requirements and not having enough capacity to meet MISO's requirements when the prompt year arrives.

MISO – Local Resource Zone 7

Figure 2 shows historical annual MISO capacity requirements for LRZ 7. This data is taken from the respective annual MISO LOLE Study Reports.

[13] Planning Year 2025-26 Indicative Direct Loss of Load (DLOL) Results published December 13, 2025. Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) Results published April 22, 2025. Planning year 2026-2027 Indicative DLOL-Based UCAP and PRMR Results published January 28, 2026.

Figure 2: Annual MISO LOLE Report Data LRZ 7

Planning Year	Source	LRR[14]	CIL[15]	LCR (ZRCs)[16]
2013/14	MISO 2013 LOLE Report	25,305	4,576	20,729
2014/15	MISO 2014 LOLE Report	24,815	3,884	20,931
2015/16	MISO 2015 LOLE Report	24,710	3,813	20,897
2016/17	MISO 2016 LOLE Report	24,715	3,813	21,309
2017/18	MISO 2017 LOLE Report	24,654	3,320	21,334
2018/19	MISO 2018 LOLE Report	24,545	3,785	20,760
2019/20	MISO 2019 LOLE Report	24,845	3,211	21,634
2020/21	MISO 2020 LOLE Report	25,370	3,200	22,170
2021/22	MISO 2021 LOLE Report	25,054	4,888	20,166
2022/23	MISO 2022 LOLE Report	24,115	3,749	20,366
2023/24[17]	MISO 2023 LOLE Report	24,428	5,087	19,341
2024/25	MISO 2024 LOLE Report	24,558	4,500	19,271
2025/26	MISO 2025 LOLE Report	23,250	3,569	19,681
2026/27	MISO 2026 LOLE Report	23,154	4,628	18,526

These numbers typically change slightly between the LOLE Study and the PRA, primarily due to updated load forecasting used in the PRA but can be used to see how local capacity requirements have changed over time. Changes in these requirements can have economic and reliability impacts and will continue to be monitored. In its seasonal construct, MISO includes an LRR, ZIA, and PRMR for each zone for each season. The difference between a zone's PRMR and its LCR is sometimes referred to as Effective Capacity Import Limit (ECIL). The ECIL is not a MISO defined term and is not representative of a physical import limitation. To meet the loss of load standard and avoid the auction clearing price being set at CONE, a zone must have enough resources located within the zone to meet its LCR, even if the LCR exceeds the PRMR. Historically, Michigan utilities have assumed a CIL of approximately 3200 MW for input in capacity expansion modeling conducted during the development of Integrated Resource Plans and other planning exercises.

[14] **Local Reliability Requirement**. Representative of the resources required for LRZ 7 to meet the LOLE standard when modeled as an island (no imports). MISO Loss of Load Expectation Study Report, Tables 2-1 through 2-4.
[15] **Capacity Import Limit**. Representative of the ability of an LRZ to import capacity from areas outside of that LRZ. MISO Loss of Load Expectation Study Report, Tables ES-3 through ES-6.
[16] **Local Clearing Requirement**. Representative of the minimum resources that must be located within a specific zone for that zone to meet the reliability standard. Calculated as shown in Table 1.1 of MISO Loss of Load Expectation Study Report.
[17] Values for summer season starting Planning Year 2023/24. Other seasons shown in Appendix B.

Figure 3 shows a comparison of LRZ 7 aggregated resources demonstrated, plus known undemonstrated resources likely to still be available, for each season in the 2029/30 planning year and MISO's resource adequacy requirement for PY 2026/27. Appendix B contains seasonal capacity position tables for the prompt, interim, and demonstration years. These numbers represent Staff's current projection based on the capacity demonstration filings and MISO publications at the time of this report, although the information is subject to change for all forward years. Unless otherwise noted, resources and resource requirements in this report are in Unforced Capacity (UCAP) Megawatts (MW), equal to Zonal Resource Credits (ZRCs).

Figure 3: U-21907 Results – PY 2029/30 LRZ 7 Capacity Position (ZRCs)

Line #		Summer	Autumn	Winter	Spring
1	Planning Reserve Margin Requirements (PRMR)	21,004	19,287	15,627	19,625
2	Local Reliability Requirement (LRR)	22,025	21,326	18,812	20,481
3	Capacity Import Limit (CIL)	4,628	5,193	4,123	5,338
4	Zonal Import Ability (ZIA)	4,628	5,193	4,123	5,338
5	Local Clearing Requirement (LCR) (L1-L4)	17,397	16,133	14,689	15,143
6	Total Owned	18,709	17,927	15,992	18,508
7	Total PPA Contracts	5,624	5,451	3,932	5,777
8	Total ZRC Contracts	1,104	1,133	884	1,175
9	Total Qualified Demand Response	1,325	561	538	660
10	Total Resources (sum of L6 through L9)	26,762	25,072	21,346	26,119
11	LCR Demonstrated Position (L10-L5)	9,365	8,939	6,657	10,976
12	PRMR Demonstrated Position (L10-L1)	5,758	5,785	5,718	6,494
13	Net Undemonstrated Capacity	-84	-119	37	-171
14	Anticipated LCR Position (L11+L13)	9,281	8,820	6,694	10,805
15	Anticipated PRMR Position (L12+L13)	5,674	5,666	5,755	6,323

(1) PY 2026 PRMR from PRA Data and held constant at prompt year value.

(2) PY 2026 LRR from PRA Data and held constant at prompt year value (LRR=LCR+ZIA).

(3) PY 2026 CIL from PRA Data and held constant at prompt year value.

(4) PY 2026 LCR from PRA Data and held constant at prompt year value.

(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.

(10) LCR position based on demonstrated resources only.

(11) PRMR position based on demonstrated resources only.

(12) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small number of resources included in the capacity demonstration that are no longer available due to recent events.

(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.

(14) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resource to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to meet its PRMR.

Prompt Year (PY 2026/27) and Compliance Year (PY 2029/30)

For the prompt year (PY 2026/27), based on the PRA Results posted April 28, 2026,[18] LRZ 7's summer Initial PRMR is 19,625 ZRCs and the LCR is 15,143 ZRCs. The total LRZ 7 resources offered in the PRA for the summer season in the prompt year is 20,721 ZRCs, which exceeds the LCR by 5,578 ZRCs and the Initial PRMR by 1,096 ZRCs. Other seasons' data is shown in Appendix B.

The final PRMRs, as determined through auction clearing, were greater than the initial targets (Initial PRMRs) in all seasons. In other words, the auction cleared above seasonal reliability targets, representing additional reliability value at cost-competitive prices. The "effective" PRMs are calculated from the Final PRMRs (determined by auction clearing):

2025 PRA Results	Initial PRM	Final PRM
Summer	7.9%	11.4%
Fall	11.6%	17.3%
Winter	18.9%	23.1%
Spring	23.4%	28.1%

Based on the resources included in the capacity demonstration filings for PY 2029/30, Staff projects LRZ 7 to have a surplus of resources compared to the projected LCR in all four seasons, as shown in Figure 3. It is important to note that these projections are subject to change. A few examples of things that could change include load forecasts, availability and performance of existing resources, development of planned new resources, and MISO policies and practices. MISO's transition to a Direct Loss of Load (DLOL) Resource Adequacy construct in Planning Year 2028/29 is expected to significantly change the requirements and accreditation of resources.

MISO has previously provided projections of both PRMR and LRR into the compliance year from the prompt year. These calculations were not available to Staff at the time of its report. In the absence of the projected PRMR/LRR values, Staff has assumed these values remain constant for the purposes of this comparison.

Interim Years (PY 2027/28 & PY 2028/29)

Appendix B also includes data and projections for each season in the interim years, PY 2027/28 & PY 2028/29. This information is derived using the same methodology as described for the compliance year. Comparing those projected requirements to the demonstrated and undemonstrated resources in LRZ 7, results in a capacity surplus for both years compared to the projected LCRs. This information is based on the best information currently available to Staff, but it

[18] Planning Resource Auction Results for Planning Year 2026/27 published April 2026.

includes several assumptions and, again, is subject to change. Similar to the compliance year, likely changes include new forecasts, unknown resource additions or subtractions, changes in generator performance, increased or decreased zonal import ability, seasonal variability, and/or changes to MISO requirements.

MISO – Local Resource Zone 2

MISO's LRZ 2 encompasses almost the entire upper peninsula of Michigan, as well as northern and eastern Wisconsin. MISO LRZ 2 has seasonal CILs of 5,072 MWs in Summer, 6,050 MWs in Fall, 5,379 MWs in Winter, and 6,133 MWs in Spring.[19] MISO does not define MW capacity import or export limits between states within the boundaries of the same LRZ. Considering LRZ 2 includes LSEs from Wisconsin (not subject to MCL 460.6w), the data available to Staff for LRZ 2 from capacity demonstration filings is not comprehensive enough to project a zonal capacity position, as Staff did in its analysis of LRZ 7. Nevertheless, all Michigan LSEs serving load within MISO LRZ 2 demonstrated sufficient resources to meet their requirements.

The 2026 MISO PRA results indicate an installed capacity surplus in the 2026/27 planning year for LRZ 2.[20]

MISO – Local Resource Zone 1

A very small fraction of Michigan's upper peninsula load is located in LRZ 1. Northern States Power, Bayfield Electric Cooperative, and the City of Wakefield municipal utility combined have less than 31 MW of peak demand in MISO LRZ 1. All LSEs in LRZ 1 demonstrated sufficient capacity to meet their obligations for PY 2029/30. The 2026/27 MISO PRA results show sufficient capacity for each season in the 2026/27 planning year for LRZ 1.

[19] Planning Resource Auction Results for Planning Year 2026/27 published April 2026.
[20] *Id.*

PJM Resource Adequacy

A few LSEs in Michigan serve load within the PJM RTO. These LSEs are still subject to the requirements of MCL 460.6w requiring sufficient capacity for four years forward in planning year 2029/30. PJM LSEs demonstrate sufficiency by providing evidence that the LSE complies with its PJM obligations.

LSEs in the PJM service territory must meet capacity obligations either through participation in PJM's Reliability Pricing Model (RPM) Base Residual Auction (BRA) or through PJM's Fixed Resource Requirement (FRR) plan. The FRR plan is an alternative to the RPM, where an LSE must demonstrate to PJM that it has enough resources to cover its projected load plus an additional reserve requirement. Both the RPM and the FRR resources are subject to monetary penalties if they fail to maintain PJM's reliability standard. PJM's resource adequacy construct is based on annual requirements.

The largest LSE operating in Michigan in PJM is Indiana Michigan Power Company (I&M or the Company).[21] I&M elects to file an FRR plan each year. I&M's most recent capacity demonstration indicates that the Company plans to continue with the PJM FRR plan, barring any major FERC-ordered changes. Staff reviewed I&M's filing and finds that they have sufficient resources to meet its obligations at PJM.

In addition to I&M's capacity demonstration, Staff also reviewed information of cooperative and municipal utility obligations in the Michigan portion of PJM's territory for PY 2029/30. The results are displayed in the table below.

Figure 4: PJM Capacity Demonstration Summary

Item	PY 2026/27	PY 2027/28	PY 2028/29	PY 2029/30
Utility Total Planning Resources, MW	4541	4846	5480	6335
Other PJM Resources, MW	360.5	356.6	406.6	456.6
Total PJM Resources, MW	4901.5	5202.6	5886.6	6791.6

Staff expects that the LSEs in the Michigan portion of PJM will continue to meet the PJM capacity obligations, based on information included in individual capacity demonstrations. If PJM LSEs were to encounter an unanticipated shortfall in the immediate future, Staff expects that it would be accommodated through the procurement of reserve resources by market purchases. As market conditions may

[21] Indiana Michigan Power Company is an electric operating company of American Electric Power Company, Inc. (AEP). I&M is a wholly owned subsidiary of AEP and is operated as a single utility in the American Electric Power System (AEP System).

change over time, Staff will continue to monitor the resource adequacy of the PJM region and the capacity plans of Michigan LSEs located within the PJM territory.

The Commission Order in Case No. U-16090 set I&M's customer choice cap amount to zero, and it was subsequently reset to ten percent on February 1, 2019, pursuant to the Commission Order and MCL 460.10a(1)(c). On February 1, 2019, I&M began enrolling customers in its customer choice program and is now fully subscribed at the cap. Currently, I&M is responsible for the capacity of its customer choice load in its FRR plan, under the PJM Reliability Assurance Agreement (RAA). If suppliers were to choose to self-supply capacity, then that capacity would also need to be included in I&M's FRR plan.

In addition, I&M currently has an application before the Commission, in Case No. U-21968, for the ex parte accounting authority to change the methodology for allocating between Indiana and Michigan retail jurisdictions the costs of current generation resources.

The North American Electric Reliability Corporation's (NERC) 2025 Long-Term Reliability Assessment categorizes PJM as having elevated risk level post 2026 and high-risk post 2029, with resource additions not keeping up with generator retirements and demand growth, though recently approved generating resources with expedited interconnection were not included in the risk analysis.[22]

The PJM Base Residual Auction (BRA) schedule has experienced delays awaiting FERC action on capacity auction related issues. The following timeline shows the published BRA schedule of auctions, with annual auctions held each May subsequently:

- June 2026 2028/29 BRA
- December 2026 2029/30 BRA
- May 2027 2030/31 BRA

PJM introduced a more robust risk model, while simultaneously implementing the Effective Load Carry Capability (ELCC) accreditation methodology for all assets in PY 2025/26. Two capacity auctions were conducted in the last year, the 2026/27 BRA and the 2027/28 BRA. PJM enforced a cap and floor on the Variable Resource Requirement (VRR) curve for both auctions, and both auctions resulted in clearing at the maximum price across all zones. The 2026/27 BRA cleared at $329.17/MW-day and secured enough capacity to meet the reliability requirement by a very narrow margin. The 2027/28 BRA cleared at $333.44/MW-day and fell short of the reliability target, resulting in a 14.4% reserve margin rather than the 20% target reserve margin. Subsequent to the BRA, an updated forecast for Summer 2027 reduced the peak load forecast by approximately 4 GW, reducing the shortfall from 6.6 GW to approximately 2.6 GW.

[22] NERC 2025 Long Term Reliability Assessment

Recent changes to PJM's capacity market include implementing a cap and floor on the VRR curve; removing renewable exemptions forcing wind, solar, and battery storage with Capacity Interconnection Rights (CIRs) to participate in the auction; accreditation reforms (E3); and significantly increased accreditation for demand response (DR), driven by increased required DR availability to all hours and revised winter peak load calculations.

LSE Capacity Demonstration Results (PY 2029/2030)

Staff appreciates the time and effort made by all Michigan LSEs to comply with the provisions of MCL 460.6w, as well as to comply with the questions, audits, contract reviews, and requests for additional information throughout this process. The LSE capacity demonstration results are reported for PY 2029/2030 because, following the initial capacity demonstration which covered four years, only the fourth year forward is required for compliance. As previously described in its September 15, 2017 Order in Case No. U-18197, the Commission requested a table be included in this report that identifies the capacity by type for each individual electric provider, without revealing the identity of any specific electric provider. The requested table, with a breakdown for each electric provider that filed a capacity demonstration, is included as Appendix A. In addition to the breakdown by individual supplier, Staff reports the following aggregate results in Figure 5 below.

Figure 5: Resource Breakdown (%) by Supplier Type Planning Year 2029/30 - Summer

Supplier Type	Owned	DR	Contract – PPA	Contract - ZRC	Auction
Muni/Co-Op Aggregate	62.5%	0.3%	25.6%	8.9%	2.8%
AES Aggregate	0.5%	0.2%	2.5%	96.8%	0.0%
Utility Aggregate	63.5%	6.3%	21.4%	4.0%	4.8%

Demand Response

As part of its analysis, Staff reviewed the LSEs' DR programs as an optional source of capacity. When used by a LSE, a reduction in demand through DR programs offsets a portion of their capacity needs. LSEs can utilize interruptible DR during critical peak times to quickly respond to bulk electric system needs, which can delay future capital investment in new generation. Behavioral DR programs allow the utility to lower its peak demand forecast, thus mitigating the need for an equal of amount supply side resources.

Demand response played a prominent role in LSEs' integrated resource plan filings, where DR is required to be considered along with traditional supply side resources for meeting capacity needs. MCL 460.6t directs Staff to complete a statewide study of DR potential in Michigan every five years, and the most

current Michigan Demand Response Potential Study was issued on October 17, 2025.[23] In addition, the Commission approved Michigan Integrated Resource Planning Parameters on December 18, 2025 in Case No. U-21867 that include provisions regarding including DR options in future integrated resource plans.

The DR levels assumed in both Consumers Energy's and DTE Electric's current integrated resource plans[24] are reflected in their capacity demonstration filing. Staff will continue to monitor these plans and the use of DR in Michigan for the foreseeable future.

Demand Response Aggregation

Pursuant to the September 15, 2017 Order in Case No. U-18369, the Commission affirmed that AESs may offer DR programs to their customers through a curtailment service provider (CSP) or third-party aggregator. The Commission made this determination in the context of finding that it will continue to review DR programs offered by AESs as part of the capacity demonstration process.

As the Relevant Electric Retail Regulatory Authority (RERRA), the Commission is aware of aggregation of approximately 115 ZRCs of DR offered into the 2026 MISO capacity market. Staff continues to work with CSPs, aggregators of retail customers (ARCs), and MISO to ensure that aggregated DR's load modifications are accounted for when dispatched on MISO's coincident peak and continues to monitor the discussions taking place regarding FERC Order 2222.

ZRC Contracts

Staff recommended that forward ZRC contracts that are used for capacity demonstration purposes specify delivery of the ZRCs in the MISO Module E Capacity Tracking (MECT) tool prior to the applicable PRA auction. This year's demonstration shows an increase in the percentage of ZRC contracts utilized this year by the utilities, municipal utilities, and cooperatives compared to last year.

An important thing to note is that ZRCs are defined in MISO's tariff and are created in the prompt year when UCAP for supply-side and demand-side resources are converted into ZRCs in the MISO MECT. ZRCs for any year further out than the prompt year are projected and don't become ZRCs until the prompt year. ZRCs are fungible products that can be sold or transferred and, in some cases, sold more than once. The characteristics of ZRCs allow for them to be easily traded and tracked within the MISO MECT. MISO has visibility into the source and transfers of those ZRCs that occur prior to the PRA in the prompt year, and those

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[23] 2025 Energy Waste Reduction, Demand Response, and Efficient Electrification Statewide Potential Study, NV5/Slipstream, October 17, 2025.

[24] DTE's current IRP filed and approved in MPSC Case No. U-21193.
CE's current IRP filed in MPSC Case No. U-21090.

ZRC transfers are audited by Staff as a secondary check on the ZRC contracts utilized in the capacity demonstrations.

At this point in time, the overall amount of ZRC contracts included in capacity demonstration filings do not impact Staff's ability to continue to make forward resource adequacy projections on a zonal basis. Staff will continue to monitor and audit ZRC contracts and ZRC transfers within the MECT going forward.

AES Load Switching

Staff requested that any AES who experienced load switching during this time provide a signed affidavit confirming the increase or reduction in their load compared to the PLC data provided by the utility with their capacity demonstration that contained the amount of load switching for each planning year. Each supplier contracting for additional customer load provided a copy of its affidavit confirming this transaction to the supplier that was losing the load to be accounted for in both suppliers' demonstrations. The load switching process was made more complex with the change to a seasonal construct.

Staff continues to see a large amount of load switching among entities. To better organize and facilitate the filing process, Staff continues to recommend that filing entities who include load switching information in their filing include it within the Contracted Resources on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. Staff also recommends that both the losing and the gaining suppliers have copies of the load switching affidavits in each of their filings, so Staff is able to easily cross check that the load is being accounted for.

Capacity Retirements and Additions

The state of Michigan continues to follow national trends showing a tightening capacity position due to the scheduled retirements outpacing the buildout of replacement capacity. Staff had the opportunity to meet with several LSEs to discuss their filings and many expressed concerns about the dwindling amount of capacity available in the compliance year, especially season-specific contracts and bilateral contracts in general. Various factors could cause delays for new additions, including broad economic factors such as supply chain constraints, labor shortages, high component prices, etc., as well as delays associated with obtaining permitting, regulatory approval, or interconnection queue delays. MISO continues to experience significant interconnection queue delays. Phase II results are expected for the 2022 cycle in May 7, 2026. The 2023 cycle is expected to enter phase II in September 2026. The 2025 cycle is expected to enter phase II when the 2023 cycle is sufficiently advanced (MISO opted to forgo a 2024 cycle).

In an effort to reduce interconnection queue congestion, MISO filed to revise its Tariff (see FERC Docket Nos. ER25-2454 & ER25-1674) to amend its generator interconnection procedures (GIP) in order to establish the Expedited Resource Addition Study (ERAS) process to provide a framework for the accelerated study

of generation projects that can address resource adequacy and reliability needs within the MISO footprint in the near term. The Commission approved the process for addressing requests filed pursuant to MISO's ERAS in the August 7, 2025 Order in Case. No. U-21902.

The tightening capacity position may be further exacerbated should demand increase faster than expected due to unanticipated loads, such as data centers, as well as electrification of the building and transportation sectors. The current capacity demonstration process does not require LSEs to consider load growth in the four year forward requirement. In light of recent increases in large load additions anticipated in Michigan, Staff recommends the Commission consider including any load growth that would significantly impact an LSE's ability to serve that load in future capacity demonstration filings (see next section for more detail).

A portion of the capacity from the Palisades Nuclear Power Plant (Palisades) was included as demonstrated capacity starting in Spring 2026. The remainder of the capacity from Palisades is being contracted by an LSE in Indiana. However, all the capacity from Palisades would provide resource adequacy benefits to MISO LRZ 7 and be counted towards meeting the LCR for LRZ 7. Re-opening of this plant is conditional on approval from the Nuclear Regulatory Commission (NRC).

In addition to the capacity resources demonstrated in this year's capacity demonstration case, the J.H. Campbell Generation Station (J.H. Campbell) is currently operating as required under the Department of Energy's 202c emergency order. J.H. Campbell is not a MISO-registered capacity resource and therefore cannot be counted as capacity toward meeting resource adequacy targets. When operating, the energy from these units is supplied into the MISO energy market.

Load Growth and the Four Year Forward Requirement

Over the past year and a half, the single largest issue in U.S. electricity markets has been forecasted load growth in all U.S. electricity markets, including MISO. This increase in load has been driven primarily by large spot-load additions, primarily data centers, and, to a lesser degree, reshoring of manufacturing, building electrification, and transportation electrification.

MISO's 2026 Long-Term Load Forecasting (LTLF) Results Summary[25] (2026 Load Forecast) shows rising electricity demand forecasts, as well as continued change in the resource mix. The 2026 Load Forecast shows increasing demand, compared with the prior forecast driven by gigawatt-scale data center campuses, higher rack power densities from Artificial Intelligence (AI) compute, and accelerated investment in strategic domestic compute infrastructure. The

[25] 2026 Long-Term Load Forecasting (LTLF) Results Summary

forecast for industrial demand is also increasing, driven by domestic semiconductor fabrication, battery manufacturing plants, and industrial electrification. In addition, MISO's 2026 LTLF Results Summary showed slightly reduced growth expectations for electrification & distributed energy resources (DERs) (Electric Vehicles (EVs), Heat Pumps, Water Heaters, and Rooftop Photovoltaic (PV)). The overall annual growth rate in the 2026 LTLF increased to 2%, up from 1.6% in the 2024 LTLF, and the current trajectory is in-line with the high end of the 2024 LTLF. The forecasted load growth in Michigan is reflective of national and regional trends, and large load tariffs and special contracts applications to the Commission have increased over the past year (see Case Nos. U-21990, U-21859, U-21986, and U-22058).

MCL 460.6w requires electric providers to demonstrate sufficient capacity to cover their obligations. When this statute was implemented, entities' demonstration year capacity obligation was equal to the prompt (current) year peak load forecast multiplied by the PRM% forecasted for year four (as published in the most recent MISO LOLE Study Report). After changes to MISO's resource adequacy construct introducing seasonal requirements, the Commission endeavored to change the state capacity demonstration to better align with the MISO construct, and one of the changes implemented was to stop using projected PRM%. After changes were implemented, demonstration year capacity obligations changed to the entity's prompt year peak load forecast multiplied by the prompt year PRM%. The peak load forecast for the prompt year has always been part of the requirement; however, the process allows an entity with a higher forecasted load in the compliance year to include this load in their demonstration (but not lower than current year forecast). Although this is included in the process and requirements document, it is unclear how Staff and the Commission would evaluate a filing from a provider who fell short of their requirement if it is based on a higher peak load forecast than the current year's forecast. Case No. U-21775 included such cases, and Staff evaluated each filing based on the current (prompt) year peak load forecast with the PRM% applied. Further guidance would be welcomed on this matter, since load is forecasted to grow increasingly in the coming years.

The current capacity demonstration process requires electric providers in MISO to demonstrate capacity for four years forward using *current* year capacity obligations, as given by MISO. Although the original process required entities to demonstrate to future forecasted levels of need, using a forecasted PRM% from MISO's LOLE Study Report, revision of the requirements in 2022 resulted in the current requirements of the prompt year PRM% for all four years. The capacity demonstration has always allowed entities to use their prompt year load forecast for all four years of the demonstration (with future year PRM% applied when this was valid) or they can use a forward-looking forecast if their forecast is higher than the prompt year requirements. While the current requirements show that electric providers can meet their current obligations, it negates any additional

obligation driven by load growth in their territory and does not *require* them to consider incremental load growth in the four year forward demonstration. A significant amount of load growth unaccounted for in the capacity demonstration process could be problematic and may conflict with the purpose of Section 6w of Act 341.

Staff recommends the Commission consider including load growth that would significantly impact an LSE's ability to serve that load in future capacity demonstrations. One possible solution is to set a forecasted threshold quantity or percentage load growth that, when triggered, electric providers would be obligated to demonstrate sufficient capacity to meet projected obligations. These projections/forecasts should reflect the most updated customer contracts, and, for investor-owned utilities, align with the forecasted load in their most recent Integrated Resource Plan (IRP).

Conclusion and Recommendations

All Michigan LSEs required to file capacity demonstrations with the Michigan Public Service Commission for planning year 2029/30, pursuant to MCL 460.6w and the August 21, 2025 Commission Order in Case No. U-21907, have filed. Staff audited the filings, contracts, and other materials and found that all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2029/30.

Staff appreciates the cooperation of all Michigan LSEs with respect to this process and the willingness to provide data and answer questions necessary for Staff to complete its review.

A summary of recommendations included in this report is below:

1. Staff recommends the Commission determine a timeline and guidelines to implement MISO's DLOL-based resource adequacy construct changes into the state capacity demonstration process prior to MISO tariff changes effective PY 2028/29.
2. Staff recommends the Commission clarify the 5% limit on resources acquired from the PRA in the demonstration year to be a limit on total annual requirement or each seasonal requirement and direct Alpena to action accordingly.
3. Staff recommends the Commission consider including load growth that would significantly impact an LSE's ability to serve that load in future capacity demonstrations.
4. Staff recommends the Commission continue to direct all LSEs to include updated prompt year and interim year capacity obligation and resource information in future filings.

5. Staff recommends the Commission direct all LSEs to provide MECT screenshots of their prompt load obligations (PRMR/PLC) to facilitate the Storage Target calculation used to comply with Public Act 235.
6. Staff recommends that filing entities who include load switching information in their filing include it within the Contracted Resources on the spreadsheet templates provided for the capacity demonstration for the demonstration years, as well as the interim years. Staff also recommends that both the losing and the gaining suppliers have copies of the load switching affidavits in each of their filings, so Staff can cross check that the load is being accounted for.

Appendix A

Planning Year 2029/30 Resource Breakdown (%) by Individual Supplier[26]

LSE	Owned	DR	Contract - PPA	Contract - ZRC	Auction
Supplier 1	34%	0%	66%	0%	0%
Supplier 2	0%	0%	0%	100%	0%
Supplier 3	0%	0%	100%	0%	0%
Supplier 4	0%	0%	0%	100%	0%
Supplier 5	54%	7%	39%	0%	0%
Supplier 6	60%	0%	18%	17%	5%
Supplier 7	0%	0%	0%	100%	0%
Supplier 8	55%	45%	0%	0%	0%
Supplier 9	0%	0%	0%	100%	0%
Supplier 10	0%	0%	0%	100%	0%
Supplier 11	0%	0%	0%	100%	0%
Supplier 12	9%	7%	84%	0%	0%
Supplier 13	0%	0%	100%	0%	0%
Supplier 14	0%	0%	100%	0%	0%
Supplier 15	43%	3%	6%	16%	32%
Supplier 16	0%	0%	100%	0%	0%
Supplier 17	0%	0%	0%	100%	0%
Supplier 18	85%	5%	10%	0%	0%
Supplier 19	66%	0%	35%	-2%	0%
Supplier 20	83%	5%	13%	0%	0%
Supplier 21	42%	22%	35%	0%	0%
Supplier 22	58%	8%	29%	5%	0%
Supplier 23	100%	0%	0%	0%	0%
Supplier 24	0%	0%	0%	100%	0%
Supplier 25	0%	0%	0%	100%	0%

[26] Suppliers (municipal and cooperative electric utilities) that combined their capacity resources are shown as one supplier in the above figure. The total number of suppliers may vary from year to year based on changes to which suppliers combine their capacity demonstrations, as well as new suppliers or suppliers no longer serving load in Michigan.

Appendix B

U-21907 Results - LRZ 7 Summer Capacity Position (ZRCs)					
Line #	Summer Values	PY 2026	PY 2027	PY 2028	PY 2029
1	Planning Reserve Margin Requirements (PRMR)	21004	21004	21004	21004
2	Local Reliability Requirement (LRR)	22025	22025	22025	22025
3	Zonal Import Ability (ZIA)	4628	4628	4628	4628
4	Local Clearing Requirement (LCR)	17397	17397	17397	17397
5	Total Owned	16604	17561	18175	18709
6	Total PPA Contracts	3160	4187	4700	5624
7	Total ZRC Contracts	774	940	860	1104
8	Total Qualified Demand Response	1194	1324	1294	1325
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	21732	24012	25029	26762
10	LCR Demonstrated Position (Line 9 - Line 4)	4336	6615	7633	9365
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	728	3008	4025	5758
12	Net Undemonstrated Zone 7 Capacity	200	-28	160	-84
13	Anticipated LCR Position (Line 10 + Line 12)	4535	6588	7792	9281
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	928	2981	4185	5674
(1) PY 2026 PRMR from PRA Data and held constant at prompt year value.					
(3) PY 2026 ZIA from PRA Data and held constant at prompt year value.					
(4) PY 2026 LCR from PRA Data and held constant at prompt year value.					
(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.					
(10) LCR position based on demonstrated resources only.					
(11) PRMR position based on demonstrated resources only.					
(12) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small number of resources included in the capacity demonstration that are no longer available due to recent events.					
(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.					
(14) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resource to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to meet its PRMR.					

U-21907 Results - LRZ 7 Autumn Capacity Position (ZRCs)					
Line #		PY 2026	PY 2027	PY 2028	PY 2029
1	Planning Reserve Margin Requirements (PRMR)	19287	19287	19287	19287
2	Local Reliability Requirement (LRR)	21326	21326	21326	21326
3	Zonal Import Ability (ZIA)	5193	5193	5193	5193
4	Local Clearing Requirement (LCR)	16133	16133	16133	16133
5	Total Owned	16356	17757	18105	17927
6	Total PPA Contracts	2970	4058	4525	5451
7	Total ZRC Contracts	784	918	699	1133
8	Total Qualified Demand Response	581	589	556	561
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	20690	23323	23885	25072
10	LCR Demonstrated Position (Line 9 - Line 4)	4557	7189	7752	8939
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	1403	4036	4598	5785
12	Net Undemonstrated Zone 7 Capacity	195	-22	313	-119
13	Anticipated LCR Position (Line 10 + Line 12)	4752	7167	8065	8820
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	1599	4013	4911	5666

(1) PY 2026 PRMR from PRA Data and held constant at prompt year value.

(3) PY 2026 ZIA from PRA Data and held constant at prompt year value.

(4) PY 2026 LCR from PRA Data and held constant at prompt year value.

(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.

(10) LCR position based on demonstrated resources only.

(11) PRMR position based on demonstrated resources only.

(12) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small number of resources included in the capacity demonstration that are no longer available due to recent events.

(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.

(14) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resource to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to meet its PRMR.

U-21907 Results - LRZ 7 Winter Capacity Position (ZRCs)					
Line #		PY 2026	PY 2027	PY 2028	PY 2029
1	Planning Reserve Margin Requirements (PRMR)	15627	15627	15627	15627
2	Local Reliability Requirement (LRR)	18812	18812	18812	18812
3	Zonal Import Ability (ZIA)	4123	4123	4123	4123
4	Local Clearing Requirement (LCR)	14689	14689	14689	14689
5	Total Owned	15802	15775	16005	15992
6	Total PPA Contracts	2544	3083	3779	3932
7	Total ZRC Contracts	639	766	485	884
8	Total Qualified Demand Response	609	602	558	538
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	19594	20227	20827	21346
10	LCR Demonstrated Position (Line 9 - Line 4)	4905	5538	6138	6657
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	3966	4600	5199	5718
12	Net Undemonstrated Zone 7 Capacity	229	10	371	37
13	Anticipated LCR Position (Line 10 + Line 12)	5133	5548	6509	6694
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	4195	4610	5571	5755

(1) PY 2026 PRMR from PRA Data and held constant at prompt year value.

(3) PY 2026 ZIA from PRA Data and held constant at prompt year value.

(4) PY 2026 LCR from PRA Data and held constant at prompt year value.

(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.

(10) LCR position based on demonstrated resources only.

(11) PRMR position based on demonstrated resources only.

(12) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small number of resources included in the capacity demonstration that are no longer available due to recent events.

(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.

(14) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resource to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to meet its PRMR.

U-21907 Results - LRZ 7 Spring Capacity Position (ZRCs)					
Line #		PY 2026	PY 2027	PY 2028	PY 2029
1	Planning Reserve Margin Requirements (PRMR)	19625	19625	19625	19625
2	Local Reliability Requirement (LRR)	20481	20481	20481	20481
3	Zonal Import Ability (ZIA)	5338	5338	5338	5338
4	Local Clearing Requirement (LCR)	15143	15143	15143	15143
5	Total Owned	15602	17513	17969	18508
6	Total PPA Contracts	3649	4389	5398	5777
7	Total ZRC Contracts	790	945	659	1175
8	Total Qualified Demand Response	703	704	656	660
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	20744	23550	24683	26119
10	LCR Demonstrated Position (Line 9 - Line 4)	5601	8407	9540	10976
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	1118	3925	5057	6494
12	Net Undemonstrated Zone 7 Capacity	177	-80	328	-171
13	Anticipated LCR Position (Line 10 + Line 12)	5778	8328	9867	10805
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	1295	3845	5385	6323

(1) PY 2026 PRMR from PRA Data and held constant at prompt year value.

(3) PY 2026 ZIA from PRA Data and held constant at prompt year value.

(4) PY 2026 LCR from PRA Data and held constant at prompt year value.

(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.

(10) LCR position based on demonstrated resources only.

(11) PRMR position based on demonstrated resources only.

(12) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small number of resources included in the capacity demonstration that are no longer available due to recent events.

(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.

(14) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resource to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to meet its PRMR.

Attachment P

Michigan AG Request for Rehearing of Order No. 202-25-3

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Order No. 202-25-3

REQUEST FOR REHEARING BY MICHIGAN ATTORNEY GENERAL DANA NESSEL

Dana Nessel
Michigan Attorney General

Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

Dated: June 18, 2025

Pursuant to section 313*l* of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Michigan Attorney General Dana Nessel, on behalf of the people of the State of Michigan, requests that the Department of Energy (Department or DOE) grant rehearing of Order No. 202-25-3 (May 23, 2025) ("Order"). The Order invoked the Department's emergency authority under section 202(c) of the Act to prevent the scheduled retirement of the J.H. Campbell power plant (J.H. Campbell) in West Olive, Michigan.

The Order is an unlawful abuse of the Department's emergency authority. Until now, the Department has reserved section 202(c) for real emergencies like natural disasters and extreme weather and has typically acted at the behest of grid operators or governmental bodies. In the Order, acting on its own motion and without notice, the Department declares that the retirement of J.H. Campbell presents an emergency. But the Order's emergency determination cannot bear even the mildest scrutiny.

The scheduled retirement of J.H. Campbell was the culmination of a carefully planned process that unfolded over four years. Under the oversight of the Michigan Public Service Commission (MPSC), Consumers Energy (Consumers) executed a plan to retire an old and inefficient facility, J.H. Campbell, and replace it largely with newer resources that would both increase Consumers' available generation capacity and save its ratepayers money. J.H. Campbell's proposed retirement was also studied carefully by the Midcontinent Independent System Operator (MISO), the regional

grid operator, which determined that the facility could retire without causing reliability issues.

In the Order, the Department uses its authority under section 202(c) in a manner untethered from the need to identify a real emergency and unhindered by the statutory requirement that the actions it orders go no further than necessary to address the emergency. The result of this overreach will be unnecessary costs imposed on already-overburdened ratepayers, needless pollution emitted into Michigan and its neighboring states, and an unprecedented intrusion into the authority of states and the Federal Energy Regulatory Commission to regulate the resource adequacy of our electric grid.

I. MOTION TO INTERVENE

The Michigan Attorney General,[1] on behalf of the people of the State of Michigan, moves to intervene in this proceeding and thereby to become a party for purposes of Section 313*l* of the Act, 16 U.S.C. § 825*l*. The People of the State of Michigan have an interest in and are aggrieved by the Order in several ways. First, households and businesses in Michigan will pay higher electricity bills as a result of the Order. The retirement of J.H. Campbell and its replacement with more cost-effective resources were elements of a careful plan expected to save Michigan

[1] *See* MCL 14.28 ("The attorney general . . . may, when in [her] own judgment the interests of the state require it, intervene in and appear for the people of this state in any other court or tribunal, in any cause or matter, civil or criminal, in which the people of this state may be a party or interested."). *See also In re Certified Question*, 465 Mich 537, 543-545; 638 NW2d 409 (2002), *Gremore v Peoples Community Hospital Authority*, 8 Mich App 56; 153 NW2d 377 (1967), and *People v O'Hara*, 278 Mich 281; 270 NW2d 298 (1936).

ratepayers nearly $600 million.[2] By ordering the continued operation of J.H. Campbell, the Order ensures that Michigan ratepayers will pay higher costs. Although the precise amounts of costs are not yet known, it is certain that Michigan ratepayers will be stuck with substantial new costs in excess of what they would have paid absent the Order.

Second, the People of the State of Michigan will suffer environmental harms as a result of the Order. J.H. Campbell is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[3] among other pollutants. By prolonging the operations of J.H. Campbell beyond its planned retirement date, the Order will increase the amount of pollution emitted in the state of Michigan, causing harms to the public health and welfare.

Third, the retirement of J.H. Campbell on May 31, 2025, was a provision agreed to as part of a settlement agreement in Michigan Public Service Commission Case (MPSC) No. U-21090, to which the Michigan Attorney General was a party. Because the Order deprives the Michigan Attorney General of the benefit of her bargain under the settlement agreement, the Michigan Attorney General will suffer a discrete and separate harm as a result of the Order.

II. BACKGROUND

A. DOE's Historical Use of Section 202(c).

[2] *See* Michigan Public Service Commission Case No. U-21090-0867, Reply Brief of Consumers at 1 – 2, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000032ZSXAA2.
[3] *See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).

In the past, the Department has used section 202(c) sparingly. The Department has used this authority only in response to concrete, particularized emergencies, and subject to limitations to ensure that the Department's reach extends no further than necessary to address the emergency at hand.

Between enactment of the Department of Energy Organization Act in 1977, Pub. L. No. 95-91, and the end of last year, the Department appears to have used section 202(c) nineteen times, not counting amendments and extension orders. DOE's first usage of section 202(c) came in response to the California Energy Crisis in 2000.[4] That order was followed by two others directing the operation of the Cross-Sound Cable, a submarine transmission line connecting New York and Connecticut that was complete but that had been delayed from entering service due to environmental permitting issues.[5] But by far the most common usage – comprising 13 of 19 instances – has been in response to extreme weather events such as hurricanes,[6] extreme cold,[7] and extreme heat.[8] In each of these weather-driven cases, the exercise of emergency power was requested by the relevant system operator or responsible utility, or both.

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[4] DOE, *Order Pursuant to Section 202(c) of the Federal Power Act* (Dec. 14, 2000). Section 202(c) was used by the Federal Power Commission prior to the Department of Energy Organization Act's creation of DOE. Those uses were generally limited to orders directing interconnection as a result of discrete and sudden emergencies or war. *See* Benjamin Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. 789, 822 (2025).

[5] *See* DOE Order No. 202-02-1 (Aug. 16, 2002); DOE Order No. 202-03-01 (Aug. 14, 2003).

[6] *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (response to Hurricane Rita); DOE Order No. 202-08-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton).

[7] *See* DOE Order No. 202-21-1 (Feb. 14, 2021); DOE Order No. 202-22-3 (Dec. 23, 2022); DOE Order No. 202-22-4 (Dec. 24, 2022).

[8] *See* DOE Order No. 202-20-2 (Sept. 6, 2020) (responding to extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 202-22-1 & 2 and amendments (same).

And in each, DOE carefully limited its remedy to ensure that generation facilities were only ordered to run in circumstances necessary to address the emergency and in a manner so as to minimize any conflict with environmental requirements.[9] DOE also limited the duration of those orders to the minimum period necessary to address the emergency, often shorter than 10 days.[10]

Prior to the Order, DOE had used section 202(c) on three occasions to delay the retirement of generation facilities.[11] These cases had key features in common. In each: (i) the order was requested by a system operator or governmental body; (ii) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (iii) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and, (iv) DOE tailored its order to go no further than necessary to address the emergency.

The first such instance came in 2004, when the District of Columbia's Public Service Commission requested an order directing the continued operation of a power plant located in Alexandria, Virginia, owned by the Mirant Corporation (Mirant). After its state regulator found the plant to be out of compliance with its air permit, Mirant abruptly announced that the plant would close.[12] The D.C. Public Service Commission, supported by the local utility, PEPCO, explained that the Mirant facility

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[9] *See supra* notes 3 – 5.
[10] *Id*.
[11] Nor did the DOE's predecessor agency, the Federal Power Commission, use section 202(c) to delay retirement of any generation units between the section's enactment in 1935 and the formation of DOE in 1977. *See* Rolsma, 57 U. Conn. L. Rev. at 843-46.
[12] DOE Order No. 202-05-3 (Dec. 20, 2005) at 1 (explaining that Mirant provided emissions information to its state regulator on August 19, 2005, the regulator demanded immediate action that same day, and Mirant decided to cease operations on August 24).

directly powered downtown D.C. and that, without it, critical federal infrastructure faced an unacceptable risk of blackout.[13] Before acting on the request, the Department commissioned an analysis from the Oak Ridge National Laboratory that confirmed the threat that the plant's closure would pose to reliability in D.C.[14] Based on that study, and based on the severity of the harm that could result from a prolonged power outage to downtown D.C., the Department issued an order directing the continued operation of the Mirant facility.[15] The Department took pains, however, to limit its order to go no further than necessary to address the emergency. The Department directed Mirant to maintain the facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[16]

Twelve years later, in 2017, the Department received a request from the Grand River Dam Authority (GRDA), an Oklahoma state agency, to direct the continued operation of Unit No. 1 at the Grand River Energy Center. GRDA explained that the Grand River Energy Center was needed to provide dynamic reactive power support to the local grid, a fact confirmed by the region's Reliability Coordinator, the Southwest Power Pool (SPP). GRDA explained, however, that it would be unable to provide reactive power without action from DOE. Unit No.1, the subject of the request, had been ordered to close by an Administrative Order of the Environmental Protection Agency. Unit No. 2 had been struck by lightning and was under repair.

[13] *Id*. at 2.
[14] *Id*. at 3 – 4.
[15] *Id*. at 5 – 8.
[16] *Id*. at 10 – 11.

And, construction of the new Unit No. 3 had been delayed because flooding in Louisiana interfered with the fabrication of essential project materials.[17] The Department granted GRDA's request, ordering Unit No. 1 to remain in operation for 90 days or until Unit No. 2 or Unit No. 3 were brought online, whichever came first.[18] The Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[19]

Later that year, the Department received a pair of requests from PJM and Dominion Virginia (Dominion) to direct the continued operation of Units 1 and 2 of the Yorktown Power Station. PJM and Dominion explained that, based on PJM load flow studies, these units were necessary to prevent uncontrolled power disruptions and shedding of critical loads in the North Hampton Roads area east of Richmond.[20] DOE issued an order directing Dominion to maintain operation at the two units, but to dispatch those units "only when called upon by PJM for reliability purposes."[21] DOE later extended the order several times due to the delayed completion of the transmission line needed to resolve the reliability issue. In doing so, DOE cited the "imminent" risk of load-shedding in the North Hampton Roads area absent extension of the order.[22] In its extension order, the Department continued to limit dispatch of

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[17] Letter Request of Grand River Dam Authority, April 11, 2017. Available at https://www.energy.gov/sites/default/files/2017/05/f34/GRDA%20public%20202%28c%29%20letter.pdf.
[18] DOE Order No. 202-17-1 at 2.
[19] *Id*.
[20] DOE Order No. 202-17-2, at 1.
[21] *Id*. at 2.
[22] DOE Order No. 202-17-4, Summary of Findings, Sept. 14, 2017.

the units only when called upon by PJM for reliability purposes and, further, directed PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating the units.[23]

B. Executive Order 14262 and the White House Strategy to Prop Up the Coal Industry.

Over the past several months, the White House and the Department have sought to radically transform how section 202(c) of the Federal Power Act is applied, departing in almost every material respect from the longstanding approach described above. As shown below, the Order cannot be understood intelligibly as a response to a discrete event or emergency akin to past orders under section 202(c). Rather, it can only be understood as part of a long-term and multi-part strategy to preserve coal and other fossil fuel generation under the guise of grid reliability concerns.

On April 8, 2025, President Trump issued Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*.[24] The Executive Order was issued concurrently with three other executive actions aimed at supporting the coal industry that were announced at a White House political event explicitly focused on that objective.[25] This event, and the related Executive Order, are one of several in a series of public actions by the Administration aimed at reversing coal plant retirements and promoting fossil fuel generation.

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[23] DOE Order No. 202-17-4 at 2.
[24] Executive Order 14262, 90 Fed. Reg. 15521 (April 14, 2025).
[25] New York Times, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry* (April 8, 2025); Executive Order 14261, *Reinvigorating Americans Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15517 (April 14, 2025); Executive Order 14260, *Protecting American Energy from State Overreach*, 90 Fed. Reg. 15513 (April 14, 2025); *Regulatory Relief for Certain Stationary Sources To Promote American Energy*, 90 Fed. Reg. 16777 (April 21, 2025).

Executive Order 14262 directs DOE to, among other things, streamline and expedite the issuance of emergency orders under section 202(c), specifically in order to "safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply [that] is necessary to prevent a complete grid failure."[26] It also directs DOE to take a subsequent series of actions related to national resource adequacy, including mandating:

- the development of a uniform methodology for assessing reserve margins and identifying "at-risk" regions;
- establishment of a process by which the developed methodology and any analysis results are regularly assessed; and,
- establishment of a protocol to identify generation resources within a region that are critical to system reliability, a mechanism under section 202(c) to ensure such generation resources are appropriately retained and, for resources over 50MW, are prevented from leaving the bulk-power system or converting their source of fuel.[27]

DOE has not yet published the analysis or protocols—the deadline provided in Executive Order 14262 is July 7.

Executive Order 14262 states that it is intended to help address the national energy emergency declared in the earlier-issued Executive Order 14,156, *Declaring a National Energy Emergency*.[28] In fact, this order is part of a broader pattern in which the Administration has expansively invoked emergency powers to achieve long-standing political objectives, rather than respond to genuine, unforeseen crises. The

[26] Executive Order 14262 section 3(a).
[27] Executive Order 14262 section 3(b), (c).
[28] Executive Order 14262, section 2.

President has declared eight national emergencies in 2025 alone—more than any other President in the first 100 days of an administration.[29]

C. The Planned Retirement of JH Campbell.

i. Description of J.H. Campbell

J.H. Campbell is a three-unit coal-fired power plant with a total rated net generating capability of approximately 1,450 megawatts (MW).[30] (The Order incorrectly states that J.H. Campbell has a capacity of 1,560 MW). In its current degraded condition, however, J.H. Campbell has a maximum capacity of 920 MW.[31] Part of that difference comes from the fact that Unit 2 is not operational, nor was it operational when the Order was issued. When Unit 2 comes back on-line later this month, the maximum capacity of the facility will be 1,180 MW. J.H. Campbell Unit 1 is 63-years-old and has a rated net generating capability of 261 MW, but now has an effective maximum output of 220 MW.[32] Unit 2 is 58-years-old and has a rated net generating capability of 356 MW. Currently out of service, when Unit 2 comes back online it will have a maximum capacity of 260 MW.[33] Unit 3 is 45 years old and has a rated net generating capability of 843 MW. The current maximum capacity of Unit 3 is 700 MW.[34] Consumers operates the entire J.H. Campbell plant and is the sole

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[29] *See* https://www.brennancenter.org/our-work/research-reports/declared-national-emergencies-under-national-emergencies-act.

[30] Michigan Public Service Commission (MPSC) Case No. U-21585, Direct Testimony of Richard Blumenstock, p. 7, Table 1 (5 Tr 1394-95); see also, https://www.consumersenergy.com/about-us/electric-generation/campbell-complex-retirement, last checked June 11, 2025 (reporting 1,450 MW of capacity).

[31] Conversation between representatives of Consumers and the undersigned counsel, June 12, 2025.

[32] *Id.*

[33] *Id.*

[34] *Id.*

owner of Units 1 and 2. Consumers owns about 93% of Unit 3, the Michigan Public Power Agency owns 4.8% of Unit 3, and Wolverine Power Supply Cooperative owns less than 2% of Unit 3.[35]

J.H. Campbell and Consumers' service territory are located within MISO Local Resource Zone 7. Most of the lower peninsula of Michigan is in MISO Zone 7, except for a small area in the southwest portion of the State, which is in PJM.

ii. State proceeding approving the retirement of J.H. Campbell

In 2021, Consumers proposed to retire J.H. Campbell in 2025 for economic reasons. The MPSC thoroughly reviewed the proposed retirement for a year in an integrated resource plan (IRP) proceeding governed by Michigan statute.[36] No party in the case opposed the retirement of Units 1 and 2; and only a few opposed the retirement of Unit 3.[37] The MPSC ultimately approved Consumers' proposed retirement of J.H. Campbell in a settlement joined by most of the parties to the case. A single party appealed the MPSC's decision to approve the retirement of Unit 3, but the Michigan Court of Appeals affirmed that decision in 2023.[38] Both the MPSC and the appeals court found that Michigan would still have more than enough generating capacity to serve demand after J.H. Campbell retired.[39]

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[35] MPSC Case No. U-21090 (Kapala Direct, 7 Tr 1739); Ex. WPSC-1, p. 19 (Agreement, p. 11), section 2.1, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001QqldAAC.

[36] MCL 460.6t.

[37] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 8.

[38] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[39] *Id.*

Michigan's IRP statute requires electric utilities whose rates are regulated by the MPSC to periodically file an integrated resource plan. The IRP is a projection of the utility's load obligations and a plan to meet those obligations.[40] The IRP statute directs the MPSC to approve a plan if the MPSC determines that it "represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."[41] To make that decision, the statute instructs the MPSC to consider whether the IRP appropriately balances seven statutory factors: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective.[42]

The IRP statute also directs the MPSC to establish – among other things – computer modeling scenarios that must be used to analyze the costs of possible plans in an IRP, including costs associated with plant retirement dates.[43] In the modeling used to prepare its 2021 IRP, Consumers determined that it would be most cost-effective to retire the entire J.H. Campbell plant in 2025.[44] Later in the proceeding, Consumers conducted more modeling that compared other possible retirement dates

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[40] MCL 460.6t(3).

[41] MCL 460.6t(8)(a).

[42] *Id.*

[43] MCL 460.6t(1).

[44] MPSC Case No. U-21090 (Blumenstock Direct, 3 Tr 99 and 147-49), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001OEXnAAO.

to a 2025 retirement and again concluded that the most cost-effective retirement date was 2025.[45] Among other things, parties to the IRP case noted that the 2025 retirement of J.H. Campbell would save ratepayers $150 million in avoidable capital expenditures.[46]

After months of litigation, most of the parties reached a settlement agreement, which Consumers filed with the MPSC on April 20, 2022.[47] The settlement agreement approved the retirement of J.H. Campbell – but it also approved the construction, procurement, and extension of other major generating resources. The net effect of these changes was to substantially increase the total generating resources available to MISO Zone 7.

iii. Effect of Consumers' overall plan on resource adequacy

MISO measures capacity for resource adequacy purposes in zonal resource credits (ZRCs). One ZRC is equal to one MW of deliverable seasonal accredited capacity, which is the net amount of capacity MISO calculates it can reasonably expect from a resource.[48]

Consumers' IRP projected that the entire J.H. Campbell plant would provide 1,346 ZRCs in 2024, its last full year of planned operation.[49] In recognition of the

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[45] *Id*. (Walz Rebuttal, 3 Tr 364-73 & Ex A-123; Blumenstock Rebuttal, 3 Tr 178-79).

[46] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, pp. 48, 55.

[47] MPSC Case No. U-21090-0777 (Settlement Agreement), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002gLkGAAU.

[48] MISO Knowledge Base, KA-01402, available at https://help.misoenergy.org/knowledgebase/article/KA-01402/en-us#:~:text=Zonal%20Resource%20Credits%20(ZRC)%20are,Seasonal%20Accredited%20Capacity%20(SAC); MISO, Resource Adequacy, available at https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc.

[49] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 33.

reduced capacity that would result from the retirement of J.H. Campbell, the settlement authorized Consumers to acquire the Covert gas plant, which Consumers has done.[50] At the time, the Covert plant was in the PJM regional transmission organization – but after acquiring it, Consumers redesignated the Covert plant as part of MISO Zone 7.[51] This action added 1,114 ZRCs to Zone 7 – almost enough by itself to offset the ZRCs removed by the Campbell retirement.[52]

The settlement also authorized Consumers to continue operating Units 3 and 4 of the Karn plant – peaking units that burn natural gas and oil – until 2031, rather than retire them in 2023 as originally planned.[53] This action maintained another 784 ZRCs in Zone 7 beyond what was in Consumers' original plan.[54] The settlement agreement also authorized Consumers to develop or acquire 250 ZRCs of new solar generation by mid-2025, increasing to 852 ZRCs by mid-2028; added 94 ZRCs of demand response and energy waste reduction by mid-2025; and added 71 ZRCs of new battery storage in 2024-2027.[55] The settlement also provided that Consumers would issue a solicitation for power purchase agreements (PPAs) that would provide capacity beginning in 2025/2026, right after J.H. Campbell's retirement.[56] The PPA solicitation would seek up to 500 MW of dispatchable generation, and up to 200 MW of clean energy resources.[57]

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[50] *Id*. at 5.
[51] *Id*. at 91.
[52] *Id*. at 50.
[53] *Id*. at 11.
[54] *Id*.
[55] *Id*. at 23.
[56] *Id*. at 6 – 7. In MISO, the planning year runs from June 1 through May 31.
[57] *Id*.

Overall, the plan approved in the settlement was projected to increase Zone 7's capacity by at least 127 ZRCs by June 2025 – an increase that will grow to at least 923 ZRCs by 2028, not including the 700 MW of additional capacity sought in the PPA solicitations.[58]

iv. MPSC approval of the settlement and affirmance on appeal

Consumers' IRP settlement agreement was supported by most parties in the case, including Consumers, Staff, the Attorney General, consumer advocates, a transmission company, commercial and industrial customers, businesses in the advanced energy sector, environmental groups, and third-party energy developers.[59] The MPSC approved the Settlement Agreement on June 23, 2022.[60] The state commission found that the plan embodied in the settlement "is the most reasonable and prudent means of meeting Consumers' energy and capacity needs."[61]

In reaching these conclusions, the MPSC specifically addressed resource adequacy.[62] After discussing the record evidence regarding the Covert plant, Karn units 3 and 4, new battery storage, and ongoing investments in solar, energy waste reduction, and demand response,[63] the MPSC concluded that "the approval of the settlement agreement will enhance resource adequacy in Zone 7 in both the near-term and long-term."[64] One party, Wolverine Power Supply Cooperative, appealed

[58] *Id.* at 24.
[59] *Id.* at 30 – 31.
[60] *Id.* at 87-93.
[61] *Id.* at 95.
[62] *Id.* at 90-93.
[63] *Id.*
[64] *Id.* at 92.

the MPSC's decision to approve the Campbell plant retirement. The Michigan Court of Appeals affirmed the MPSC. The court specifically addressed resource adequacy, quoted the MPSC's findings about the generating resource additions, and found that the state commission's decision was based on substantial evidence.[65]

v. Subsequent proceedings before the MPSC show that both Consumers' service territory and Michigan as a whole will have sufficient capacity this summer and for years to come

Filings in MPSC proceedings regarding capacity supply and resource adequacy demonstrate that there is no capacity shortfall. To the contrary, the most current available information is that both Consumers and MISO Zone 7 will have sufficient capacity this summer and for years to come. On June 10, 2025, Consumers reported that it now has a surplus of 273 ZRCs for this summer.[66] Consumers further reported that it expects J.H. Campbell will not contribute any ZRCs to the Company's summer position.[67]

Consumers' ZRC projections compare Consumers' available resources not just to projected actual demand but to the planning reserve margin requirement (PRMR). MISO establishes the PRMR as the amount of reserve margin target necessary to meet NERC's Loss of Load Expectation (LOLE) standard of 1 day in 10 years.[68] NERC

[65] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[66] *See* Attachment D, Consumers' Responses from June 10, 2025.

[67] *Id*.

[68] MISO Resource Adequacy Business Practices Manual, BPM-011-r31, p. 27, Section 3.4.2 LOLE Analysis; MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 9.

defines the LOLE as "the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand."[69]

For Michigan as a whole, the MPSC Staff finds in its annual capacity demonstration report that – except for one small municipal utility – all Michigan load serving entities "were able to procure the necessary capacity to demonstrate compliance for the current planning year in all four seasons" in Planning Year 2025-26.[70] The Staff Report also finds that there are more than enough resources in Zone 7 to meet the MISO Local Clearing Requirement (LCR) – which is the minimum amount of resources that must be located within a MISO local resource zone to meet the reliability standard.[71] While Zone 7 did not have enough internal resources to meet its entire PRMR, it is not required to do so under MISO rules, and the zone is able to import 785.5 ZRCs of external resources to meet its PRMR for the current planning year.[72]

Looking ahead, the Staff Report projects that Zone 7 will have more than enough resources to meet both its LCR and the PRMR in each of planning years 2026, 2027, and 2028.[73] Zone 7's LCR surplus will increase each year to reach 4,975 ZRCs by Planning Year 2028, and its PRMR surplus will increase each year to reach 3,428 ZRCs by Planning Year 2028.[74]

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[69] NERC Probabilistic Assessment Technical Guideline, August 2016, p. 2.
[70] MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 6.
[71] *Id*. at 16.
[72] *Id*.
[73] *Id*. at p. 26, Appendix C.
[74] *Id*.

vi. MISO approved the retirement of J.H. Campbell after a detailed study process governed by MISO's FERC-approved tariff

More than three years before the Secretary issued Order 202-25-3, MISO determined via a detailed technical study that retirement of J.H. Campbell would not materially impact reliability in MISO. That determination remains in effect.

Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires that the owner of a Generation Resource that is planning to suspend operations of all or a portion of that resource must notify MISO at least 26 weeks in advance by submitting a completed Attachment Y Notice.[75] The Tariff states that MISO will perform an Attachment Y Reliability Study to determine whether the Generation Resource is necessary for the reliability of the Transmission System based on analyses described in the Tariff and criteria in the MISO Business Practices Manuals.[76]

On December 14, 2021, Consumers submitted to MISO an Attachment Y notice of intent to suspend J.H. Campbell Units 1, 2, and 3 effective June 1, 2025.[77] After more than a year of study, MISO approved the suspension on March 11, 2022.[78] MISO stated that after reviewing the J.H. Campbell suspension for power system reliability impacts, MISO had determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,

[75] MISO Tariff, Section 38.2.7(a)(i).
[76] MISO Tariff, Section 38.2.7(c).
[77] Attachment C (Letter dated December 14, 2021, from Timothy J. Sparks, Consumers Energy, to Andrew Witmeier, MISO, and Attachment Y Notification of Generating Resources Change of Status).
[78] Attachment C (Letter dated March 11, 2022, from Andrew Witmeier, MISO, to Timothy J. Sparks, Consumers Energy, re: Approval of Campbell Units 1, 2 & 3 Attachment Y Suspension Notice).

2 & 3 may suspend without the need for the generators to be designated as a System Support Resource ('SSR') units as defined in the Tariff."[79]

On May 27, 2025, MISO requested that Consumers submit a modified Attachment Y request with a new suspension start date of August 21, 2025, consistent with the date in Order 202-25-3.[80] Consumers submitted the modified Attachment Y notice with the new date on May 28, 2025.[81] On May 30, 2025, MISO notified Consumers that with the modification, "the Attachment Y remains as is, still approved, except with a new/different start date."[82]

D. The Order

On May 23, 2025, the Secretary of Energy issued the Order pursuant to section 202(c) of the Federal Power Act, determining that an emergency exists in the region of the country served by MISO "due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" and ordering Consumers and MISO to ensure the continued operation of J.H. Campbell for at least 90 days notwithstanding the longstanding plan to retire the facility on May 31, 2025. In issuing the Order, the Department issued a press release that, like Executive

[79] *Id*.
[80] Attachment C (Email dated May 27, 2025, from Huaitao Zhang, MISO, to Kathy Wetzel, Consumers Energy).
[81] Attachment C (Email dated May 28, 2025, from Rachael Moore, Consumers Energy to Huaitao Zhang, MISO).
[82] Attachment C (Email dated May 30, 2025, from Marc Keyser, MISO, to Rachael Moore, Consumers Energy).

Order 14262, states the Order "is in accordance with President Trump's Executive Order: Declaring a National Energy Emergency."[83]

Over four short paragraphs, the Order outlines the "emergency situation" allegedly necessitating invocation of section 202(c) authority. It points primarily to "*potential* tight reserve margins during the summer 2025 period," citing to the North American Electric Reliability Corporation (NERC) 2025 Summer Reliability Assessment, including the statement that MISO is "at elevated risk of operational reserve shortfalls during periods of high demand or low resource output."[84] The Order then describes the retirement of thermal generation capacity including the retirement of approximately 2,700 MW of coal-fired capacity in Michigan since 2020 and the scheduled May 31, 2025, retirement of J.H. Campbell.[85] The Order acknowledges Consumers' acquisition of 1,200 MW of replacement natural gas capacity and MISO's April 2025 conclusion that its auction resulted in "demonstrated sufficient capacity,"[86] but does not reference, let alone consider, the extensive processes that MISO and the MPSC undertook to evaluate and mitigate any reliability or resource adequacy risk that would be caused by the retirement of J.H. Campbell.[87] Nor does the Order describe any actions that MISO or Consumers have taken or could take to mitigate any alleged emergency conditions short of ordering the continued operation of the plant. Rather, it relies almost exclusively on:

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[83] DOE Press Release (May 23, 2025) available at https://www.energy.gov/articles/energy-secretary-issues-emergency-order-secure-grid-reliability-ahead-summer-months.
[84] DOE Order 202-25-3 at 1 (emphasis added).
[85] *Id.* at 1.
[86] *Id.* at 2.
[87] *See* Section II.C *supra*.

- The general statement in NERC's 2025 Summer Reliability Assessment that there is anticipated to be "elevated risk of operating reserve shortfalls"
- Language in MISO's Planning Resource Auction Results for Planning Year 2025-26 that, "for the northern and central zones, which includes Michigan, 'new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources,'" and that the results "reinforce the need to increase capacity" and,
- Language from the MISO Auction Results that the summer months have, relative to other times, the "highest risk and tighter supply-demand balance."[88]

The Order concludes that "additional dispatch of the Campbell Plant," for the 90-day duration of the order and on conditions contained in the order, "is necessary to best meet the emergency and serve the public interest."[89] As a result, the Order mandates that:

- MISO and Consumers Energy take all necessary steps to ensure the Campbell Plant is available for dispatch;[90]
- MISO employ economic dispatch of the plant, and that Consumers comply with all such dispatch orders;[91]
- All operation of J.H. Campbell "must comply with applicable environmental requirements . . . to the maximum extent feasible while operating consistent with the emergency conditions."[92]
- MISO submit reports to DOE on plant operations, environmental impacts, and actions taken to comply with the Order.[93]
- "Relevant governmental authorities" take such action as necessary to enable MISO to effectuate the dispatch and operation of the units.[94]
- Consumers request any necessary revisions or waivers to effectuate the order with FERC.[95]

III. STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

[88] DOE Order 202-25-3 at 2.
[89] DOE Order 202-25-3 at 2.
[90] *Id.* at 2 (Ordering Paragraph A).
[91] *Id.* (Ordering Paragraph A).
[92] *Id.* at 3 (Ordering Paragraph C).
[93] *Id.* at 3 (Ordering Paragraph B, D).
[94] *Id.* at 3 (Ordering Paragraph E).
[95] *Id.* at 3 (Ordering Paragraph F).

As explained in Section IV below, the Michigan Department of Attorney General submits the following statement of issues and specifications of error:

1. The Order is contrary to law because it fails to establish the existence of an emergency under section 202(c) or the Department's regulations implementing section 202(c). The statutory text, legislative history, judicial construction and DOE's regulations all confirm that an "emergency" is an occurrence that is sudden, unexpected and requiring immediate action. The Order introduces no facts that would satisfy that definition. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371; *Richmond Power and Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978); *Otter Tail Power Co. v. Fed. Power Comm*., 429 F.2d 232, 233-34 (1970).

2. The Order is contrary to law because it exceeds the Department's statutory authority. Abusing a statute meant only for emergencies, the Order intrudes on authority reserved to States and to other federal regulators to regulate resource adequacy. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy, or the authority to decide which power plants may retire except for so long as a true emergency exists. The Department may not "discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority." *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

3. The Order fails to present substantial evidence for its emergency determination and fails to exercise reasoned decision-making by ignoring critical facts and shortcomings in its analysis. Specifically, the Order: (i) presents a discussion of the NERC 2025 Summer Reliability Assessment that is unreasoned, incomplete, and that fails to substantiate the existence of an emergency; (ii) the Order's apparent reliance on generator retirements in Michigan as evidence of an emergency is unreasonable; (iii) the Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless, (iv) the Order fails even to acknowledge that MISO approved the retirement of J.H. Campbell through the study process governed by its FERC-approved tariff; (v) the Order makes no effort to review the proceedings before the MPSC, or to note any consultation with Michigan officials as required by 42 U.S.C. § 7113; (vi) the Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate. *E.g. Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017) (order under the Federal Power Act must reflect "a principled and reasoned decision supported by the evidentiary record" (quotation marks omitted)); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (agency must examine the relevant data and articulate a satisfactory

explanation for its action including a rational connection between the facts found and the choice made); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962) (an "agency must make findings that support its decision, and those findings must be supported by substantial evidence").

4. The Order is arbitrary and capricious and contrary to law because section 202(c) provides no authority for the Department to command a generator to engage in "economic dispatch." 16 U.S.C. § 824a(c); *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001) (absent statutory authorization, an agency's "action is plainly contrary to law and cannot stand").

5. The Order is arbitrary and capricious and contrary to law because the Department failed to limit its remedy as required by section 202(c)(2). The Order adheres to neither the temporal constraint nor the environmental constraints imposed by section 202(c)(2). 16 U.S.C. § 824a(c)(2).

6. The Order violates the National Environmental Policy Act because it fails to assess the environmental consequences of a major federal action significantly affecting the human environment. 42 U.S.C. § 4321; *et seq*.

IV. REQUEST FOR REHEARING

A. The Department Has Failed to Establish the Existence of an Emergency under Section 202(c) or the Department's Regulations Implementing Section 202(c).

i. Congress limited DOE's authority under section 202(c) to the unique circumstances of war or emergency

Section 202(c) confers an extraordinary power. Enacted in 1935, section 202(c) empowered the Federal Power Commission to command action from market participants and – crucially – to do so freed from most of the core procedural safeguards, jurisdictional boundaries, and substantive limitations that undergird the rest of the Federal Power Act. While the rest of the Act authorizes Commission action

only after opportunity for hearing,[96] section 202(c) allows the Commission (now the Department) to act on its own motion and without prior notice. And in profound contrast to the rest the Federal Power Act and general utility law principles,[97] section 202(c) empowers the Department to require utilities to incur costs – through a command to provide generation or transmission service – without first considering the impact to ratepayers or whether the resulting rates will be just and reasonable.

It comes as no surprise, therefore, that when Congress granted the Commission this extraordinary power, Congress restricted its use to extraordinary circumstances. Section 202(c) authorizes action only "[d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." The Act permits some measure of flexibility with respect to what type of events may cause the emergency, allowing for "other causes" beyond those enumerated. But the Act is clear that any such event, including a "shortage of electric energy," must be one that constitutes an "emergency."

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[96] *See e.g.*, 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o & 824p.

[97] Two cornerstones of the law of regulated utilities are the filed rate doctrine and the rule against retroactive ratemaking. As FERC has explained, "a central purpose of the filed rate doctrine and the rule against retroactive ratemaking is to protect ratepayers from being subjected to an additional surcharge above the rate on file for service already performed." *Old Dominion Elec. Coop.*, 154 FERC ¶ 61,155 (2016). In its June 6, 2025, complaint filed in FERC Docket No. EL25-90, Consumers asserts that the filed rate doctrine and the rule against retroactive ratemaking are inapplicable in the context of an order under section 202(c).

Because the Act does not define "emergency," the Department must look first to the public meaning of that word at the time of enactment. Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "sudden or unexpected appearance or occurrence . . . . An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency." Contemporary dictionaries likewise define "emergency" to refer to a circumstance that is "unexpectedly arising, and urgently demanding immediate attention."[98]

These definitions accord with the legislative history of the Federal Power Act, which characterized section 202(c) as an authority to be used in response to "crises":

> This is a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose. Drought and other natural emergencies have created similar crises in certain sections of the country; such conditions should find a federal agency ready to do all that can be done in order to prevent a break-down in electric supply.[99]

The few courts that have had occasion to opine on the meaning of "emergency" in section 202(c) have likewise emphasized that the provision applies in very limited circumstances, and not as a tool to address longer-term, structural concerns. In *Richmond Power and Light v. FERC*, the D.C. Circuit upheld the Commission's judgment that the dependence on foreign oil occasioned by the 1973 oil embargo was

[98] *See Acuity Ins. Co. v. McDonald's Towing & Rescue, Inc.,* 747 F. App'x 377, 380–81 (6th Cir. 2018) (addressing a statute that leaves "emergency" undefined and quoting 7 Oxford English Dictionary 231 (2012) among others to supply a definition).
[99] S. Rep. No. 74-621 at 49 (1935).

not an "emergency" under the Act, noting that section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[100]

In *Otter Tail Power Co. v. Fed. Power Comm'n,* the U.S. Court of Appeals for the Eighth Circuit described section 202(c) as enabling the Commission to "react to a war or natural disaster." The court also distinguished section 202(c) from section 202(b), under which the Commission may also order interconnections, but only after a hearing. The court explained that, in contrast to section 202(c), which "enables the Commission to proceed without notice or hearing" to address immediate crises, section 202(b) "applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[101]

Through its regulations, the Department has also interpreted "emergency" for purposes of section 202(c) to mean circumstances that arise suddenly and unexpectedly:

> "Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities.[102]

In summary, the plain meaning of the statutory text, its legislative history, judicial construction, and the Department's own regulations all establish that an

[100] 574 F.2d 610, 615 (D.C. Cir. 1978).
[101] 429 F.2d 232, 234 (8th Cir. 1970).
[102] 10 C.F.R. § 205.371.

"emergency," including one occasioned by a "shortage of electric energy," must be sudden, unexpected, and demanding of "immediate action."

ii. The Order fails to present facts establishing an emergency under section 202(c) or the Department's regulations

Even taken as complete and accurate claims (which they are not), the factual assertions made in the Order fail to describe an "emergency." The Order does not claim that the retirement of J.H. Campbell was sudden or unexpected. Nor could it. The retirement of J.H. Campbell was carefully planned over a period of years and was approved by the MPSC through a public proceeding. Further, Consumers' plan to retire J.H. Campbell included a commitment to procure replacement resources that improved its capacity position. And Consumers' proposal to retire J.H. Campbell was approved in advance by MISO after a thorough review of its impact on reliability.

Nor did the publication of NERC's 2025 Summer Reliability Assessment in May 2025 transform a long-planned retirement into an event with sudden or unexpected implications requiring immediate action. The Order notes that the 2025 NERC Summer Reliability Assessment characterizes MISO as being at an "elevated risk of operating reserve shortfalls." But NERC's "elevated risk" designation in no way signifies an emergency condition. "Elevated risk," it should be emphasized, falls *below* NERC's highest risk designation: that of "high" risk.[103] NERC's decision not to place MISO in the highest risk category in its Summer Reliability Assessment is

[103] The "High" risk designation refers to a risk of shortfall during normal peak conditions, whereas the "Elevated" risk designation refers to a risk of shortfall during above-normal peak conditions. See Attachment A, NERC, 2025 Summer Reliability Assessment at 6.

in itself powerful evidence that there is no "emergency" stemming from a lack of operating reserves.

The "elevated risk" designation is also far from unusual. In the same report, NERC also designated the systems overseen by SPP, the Electric Reliability Council of Texas (ERCOT), and the New England Independent System Operator (ISO-NE) as at "elevated risk."[104] Except for 2022, when it was designated as "high" risk, MISO has been designated as "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[105] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021.[106] In effect, what the Order implies through its reliance on the NERC report's "elevated" risk designation, is that the fifteen states of MISO – along with large swaths in the rest of the United States – have been in an uninterrupted state of emergency for many years on end. This interpretation, if credited, would effectively read the word "emergency" out of section 202(c).

The Order's hand-waving reference to "potential tight reserve margins" identified in the 2025 NERC Summer Reliability Assessment likewise fails to describe an emergency. The very fact that the Order attempts to rely on "potential" future conditions itself contradicts the notion that MISO is presently facing an

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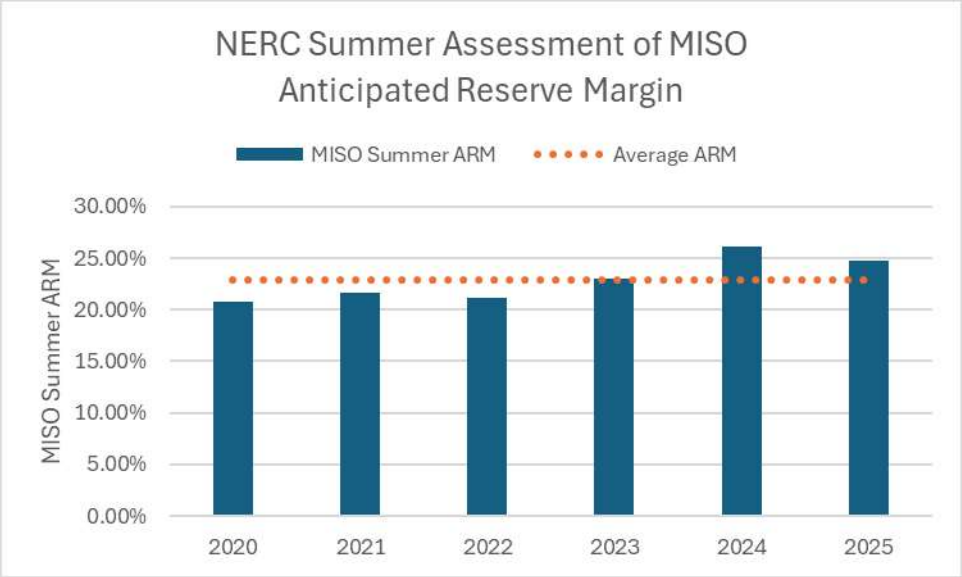
[104] *Id*.

[105] *See* NERC Summer Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

[106] *See* NERC Winter Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

emergency as conceived under section 202(c). Moreover, the actual reserve margins in MISO this summer do not support an emergency determination. The NERC report calculated MISO's anticipated reserve margin for Summer 2025 as 24.7%.[107] This figure substantially exceeds NERC's "Reference Margin Level" for MISO of 15.7%,[108] which is the level that NERC has "established for the areas to meet resource adequacy criteria."[109] MISO's anticipated reserve margin of 24.7% is also *higher* than its average of recent years. The chart below shows the anticipated reserve margin for MISO as calculated in the NERC Summer Reliability Assessment for each year.[110] The chart shows that the 2025 anticipated reserve margin of 24.7% exceeds the 2020-2025 average of 22.9%. Again, the Order has failed to describe a circumstance that is "unexpected," "sudden" or "demanding of immediate attention."



[107] Attachment A, NERC, 2025 Summer Reliability Assessment at 10.
[108] *Id*. at 44.
[109] *Id*. at 15.
[110] *See* NERC Summer Reliability Assessments years 2020 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

The other factual assertions in the Order likewise fail to describe an emergency. The Order devotes one of its few substantive paragraphs to explaining that various generation units have retired in Michigan, reaching back as far as 1997.[111] But generation units retire everywhere as part of the normal, continuous cycle through which old units are replaced with new ones. The unsurprising fact that generation units have retired in Michigan over the last 28 years says nothing about whether there is presently adequate generation in the State, and even less about whether an emergency exists in the region as a whole.

The Order then points to the results of the April 2025 MISO Planning Resource Auction. But these results explicitly contradict the claim that an emergency exists in MISO. The Order acknowledges MISO's conclusion that the auction "demonstrated sufficient capacity." In fact, the Order truncates this quote, which stated in full that: "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."[112] Remarkably, the Order attempts to brush aside the obvious import of this conclusion, preferring instead to focus on the second half of the sentence. But the second half of that sentence merely refers to the fact that the summer price for capacity in MISO, which separates the auction results by season, is high*er* and has a tight*er* supply/demand balance than those of the fall, winter and spring seasons (a fact illustrated by the chart below the header text).

[111] Order at 1.
[112] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 12.

This sentence does not indicate any kind of shortfall in the summer season, much less an emergency shortfall.

The Order also quotes from a slide that states "for North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[113] But this slide is simply noting that the total capacity of resources *offered* into the 2025 auction in the North/Central region was lower than what was offered into the 2024 auction. This slide does not say that the total amount of capacity *procured* in the North/Central region through the auction was inadequate. In other words, this slide is in no way inconsistent with the conclusion in the same report that the "2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels."[114] Further, even as a characterization of the total capacity offered into the auction, the Order ignored a crucial fact in this slide. The slide shows that the reason for the decrease in capacity offered was not because of a decrease in physical generating capacity, but because of a change in the capacity accreditation of various resources—most notably, the very "dispatchable generation" that the order prioritizes. This change in MISO's capacity accreditation methodology occurred over the previous year.[115] The bar chart in Attachment B shows a reduction in accredited capacity for gas and coal of 3.4 GW, which is greater than the overall reduction in offered

[113] *Id*. at 13.
[114] *Id*. at 12.
[115] *Midcontinent Independent System Operator, Inc*., 189 FERC ¶ 61,065 (Oct. 25, 2024).

capacity.[116] In other words, MISO concluded that coal (and gas) resources, such as J.H. Campbell, should be deemed to contribute less to capacity requirements than it had previously assumed.

B. Abusing an Authority Meant for True Emergencies, the Order Intrudes on Authority Reserved to States and to Other Federal Regulators.

i. Resource adequacy is regulated by the states, and by FERC under other provisions of the Federal Power Act

Resource adequacy refers to the capacity of an electric power system to meet demand reliably at all times, including during system peaks and through potential outages. Resource adequacy is "measured at the system level to capture the overall impact of outages of individual components including generators and transmission."[117] Resource adequacy planning is the process by which utilities and system operators, under regulatory supervision, ensure resource adequacy. Resource adequacy planning involves technical and economic considerations that go into determining what resources are added to the grid and which resources should retire and when.

With respect to regulatory oversight for resource adequacy, section 201 of the FPA, 16 U.S.C. § 824(b)(1), reserves authority over generation facilities to the states. It states in pertinent part: "The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over*

[116] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 13.
[117] NREL, Resource Adequacy Basics, available at https://www.nrel.gov/research/resource-adequacy.

facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[118]

Some states have retained this authority over resource adequacy in its entirety.[119] Others have directed their utilities to join RTO/ISOs that, through their tariffs, impose resource adequacy requirements. Those RTO/ISOs also generally establish markets that allow market participants to buy and sell capacity and thereby to facilitate market entry and exit decisions based on price signals. Resource adequacy requirements in RTO/ISO tariffs have been held to be practices affecting wholesale rates subject to the jurisdiction of FERC under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d & 824e.[120]

In Michigan, the regulation of resource adequacy planning has both a state and federal aspect. As a member of MISO, Consumers has a capacity obligation under the MISO tariff. MISO's resource adequacy requirements, however, are designed to be complementary to the primary role of the states in ensuring resource adequacy.[121]

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[118] *Id*. (emphasis added).

[119] *See Devon Power LLC et al.,* 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[120] *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).

[121] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, 62,606 at P 13 (2020) ("approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities ... within the [MISO] region."); *see also id*. ("MISO's proposed Tariff language

Consumers' investment decisions are regulated by the MPSC. Through the state IRP process (described in Section II.C above), the MPSC exercises regulatory authority over Consumers in order to ensure that the utility obtains the amount of capacity it needs to meet its obligations under the MISO tariff, and that it does so at the best value to ratepayers, and with a composition of resources that otherwise complies with state law, including state environmental requirements.

ii. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy

The Order indicates that the Department believes it has the authority to decide which power plants may retire and when, not based on the kind of real emergency that has justified past action, but rather based on its own policy preferences. The Department appears to want to place its own judgment about operating reserve margins ahead of MISO's, and its own preference for which resources are employed to maintain resource adequacy ahead of Michigan's. In effect, the Department appears to read section 202(c) so as to give itself authority to regulate resource adequacy. Any ambiguity on this point was put to rest by the Department's June 13 letter referring cost recovery issues for J.H. Campbell to FERC. In that letter, the Department, through counsel, acknowledged that resource adequacy concerns

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explains that the resource adequacy requirements 'are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction.' In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's Auction is not—*and has never been*—the primary mechanism for its [Load Serving Entities] to procure capacity."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]").

motivated the Order and went so far as to purport to dictate whether J.H. Campbell would be counted as a capacity resource pursuant to the MISO tariff.[122]

Section 202(c) does not provide the Department with the authority it claims. Had Congress intended to vest regulatory authority over resource adequacy in section 202(c), – displacing both state law and sections 205 and 206 of the Federal Power Act, – it would have stated so clearly. But of course it did not. The authorizing language says no more than that DOE may "require by order . . . such generation . . . of electric energy as in its judgment will best meet the emergency and serve the public interest." Indeed, it defies logic that, had Congress intended to empower DOE to be the general decider of which power plants may retire across every utility and independent power producer across the entire country – a function with profound implications for rates, state sovereignty, and a broad array of other stakeholder interests – that Congress would have done so through what may be the only provision in the Federal Power Act that empowers the regulator to act without first assessing the effect on ratepayers or seeking public input, and one of the only provisions that extends to otherwise non-jurisdictional utilities such as public power entities and those in ERCOT.

But even if the text of section 202(c) could, theoretically, be stretched to such an expansive reading (which it cannot), the United States Supreme Court has emphatically rejected statutory interpretations whereby an agency "claim[s] to discover in a long-extant statute an unheralded power representing a transformative

[122] FERC Docket No. EL25-90, submission of Dep't of Energy, June 13, 2025 ("Because the May 23, 2025 Order is predicated on the shortage of facilities for the generation of electric energy and other causes, such as resource adequacy concerns, the Campbell plant shall not be counted as a capacity resource.").

expansion in its regulatory authority."[123] That is exactly what the Department seeks to do here. It seeks to discover in a 90-year-old statute a basis to exercise much broader regulatory authority than it ever has in the past. While it is true, as we explain above in section II.A, that the Department has used section 202(c) to delay power plant retirements on three occasions over the 90-year history, it has always done so at the request of a system operator or governmental body and in a manner narrowly tailored to prevent a concrete and particularized emergency. It has never done so simply to impose its policy preferences ahead of the judgment of those bodies responsible for resource adequacy.

C. The Order Fails to Present Substantial Evidence for its Emergency Determination and Fails to Exercise Reasoned Decision-making by Ignoring Critical Facts.

The Order relies on three sources of evidence for its emergency determination: the NERC 2025 Summer Reliability Assessment, generator retirements in Michigan, and the results of MISO's 2025 Planning Resource Auction. None of these three sources provide evidence that an emergency exists. By relying on these sources, and by misconstruing each of them, the Order fails to exercise reasoned decision-making.

The Order also entirely ignores several other critical facts and considerations. The Order ignores the fact that MISO approved the deactivation of J.H. Campbell. The Order ignores the conclusions of the MPSC proceeding that approved the retirement of J.H. Campbell. And even if it were correct that a capacity shortfall

[123] *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

exists in MISO, the Order fails to explain why preventing the retirement of J.H. Campbell through an emergency measure is necessary to address the shortfall.

i. The Order's discussion of the NERC 2025 Summer Reliability Assessment is unreasoned and incomplete

As explained above in Section IV.A, the Order's discussion of the NERC 2025 Summer Reliability Assessment is both incomplete and unreasoned. Specifically, the Order fails to explain (i) why the NERC report supports an emergency finding for MISO given that NERC did not put MISO in the "high" risk category, (ii) why NERC's designation of MISO as at "elevated" risk provides evidence of a "sudden" or "unexpected" circumstance given that MISO has been at this risk level or higher for years running, and (iii) why the "potential tight reserve margins" identified in the NERC report constitute an emergency given that MISO well exceeds the NERC reference margin level and even exceeds its own average Summer anticipated reserve margin over the 2020 – 2025 period.

ii. The Order's apparent reliance on generator retirements in Michigan is unreasonable

The Order attempts to support its emergency finding by recounting the fact that various power plants have retired in the state of Michigan.[124] As explained above, because power plant retirements are a regular occurrence in the electric power sector, the Order's discussion of this topic fails to present even *prima facie* evidence of an emergency. It also fails to exhibit reasoned decision-making in two key respects. First, it is unreasonable to point to capacity retirements in isolation

[124] Order at 1.

without also considering all the other factors that contribute to resource adequacy. Such factors include capacity additions, changes in load, load shape and load flexibility, demand response, transmission access to external resources, etc. Of course, MISO *did* consider all those factors in the modeling that went into the Attachment Y process through which it approved the deactivation of J.H. Campbell.[125]

Second, the Order fails to explain how power plant retirements in Michigan are related to the emergency the Department purports to identify. In past orders where the Department has used section 202(c) to delay a power plant's retirement, the Department has acted on application of a utility or system operator to address a discrete, localized emergency that would be caused by the impending retirement.[126] The Department makes no such claim to geographic specificity here. Rather, the remainder of the "Emergency Situation" section of the Order appears to describe a purported emergency throughout MISO, insofar as it relies on NERC's general statements about MISO reserve margins and the results of the MISO Planning Resource Auction. Thus, the Order fails to explain why it is relying on power plant retirements in a single state—Michigan—to support its claim that an emergency exists in the region as a whole.

iii. The Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless

[125] *See* MISO Transmission Planning Business Practices Manual, BPM-020-r32 Section 6.2 (Generator Retirement and Suspension Studies and System Support Resources), Section 6.2.3 (Study Scope Development).
[126] *See* Section II.A *supra*.

As explained in Section IV.A above, the Order cites to the MISO planning reserve auction report while ignoring the statement in that report that: "The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels." It is entirely unreasonable for the Department to cite this report as evidence of an emergency when the report has concluded exactly the opposite. The Order's effort to focus on other aspects of the report are equally unreasonable. The unremarkable statement that summer prices are higher than prices in other seasons and therefore reflect a tighter supply/demand balance falls far short of providing evidence for an emergency. Likewise, the Order's reliance on the fact that less capacity was *offered* in the 2025 auction than was offered into the 2024 auction hardly describes an emergency. Further, the Order fails to note the information conveyed in the slide it quotes from, which shows that the only material change between 2024 and 2025 was a result in a change in capacity accreditation values rather than a change in physical resources available.

iv. The Order fails to acknowledge that MISO approved the retirement of J.H. Campbell

As explained in Section II.C above, after a robust, technical, and considered process, MISO approved the retirement of the three J.H. Campbell units pursuant to the study process governed by its tariff. MISO concluded that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria." As the system operator, MISO has more in-depth knowledge of its system than the Department does. The Department should have explained why it reached a

different conclusion than MISO. Instead, the Order failed even to mention that MISO conducted this study and approved the retirement.

v. The Order makes no effort to review the findings of the MPSC or to demonstrate consultation with Michigan as required by 42 U.S.C. § 7113

The Order acknowledges that Consumers acquired the Covert gas plant, but in all other respects fails to acknowledge the MPSC proceeding that approved Consumers' IRP settlement entailing retirement of J.H. Campbell. As explained above in Section II.C, acquiring the Covert gas plant was not the only action Consumers took as part of that IRP. The IRP also delayed the retirement of the peaking units at the Karn facility and included the acquisition of other new resources, with the result that Consumers' capacity position was set to improve materially even after the retirement of J.H. Campbell. The Order also ignores the Michigan capacity demonstration proceedings that found both Consumers and MISO Zone 7 have sufficient capacity resources in 2025 and in the years to come.

Section 103 of the Department of Energy Organization Act, 42 U.S.C. § 7113, provides:

> Whenever any proposed action by the Department conflicts with the energy plan of any State, the Department shall give due consideration to the needs of such State, and where practicable, shall attempt to resolve such conflict through consultations with appropriate State officials.

The Order plainly conflicts with Michigan's energy plan, as reflected in the MPSC's approval of Consumers' IRP. Equally clearly, the Order does not give "due consideration" to the needs of Michigan. Nor does it appear that the Department

made any attempt to resolve the conflict it created through consultation with the appropriate State officials. The Department, therefore, has failed to comply with Section 103 of the Department of Energy Organization Act. A practical consequence of the Department's apparent failure to consult with the State is that the Order lacks basic information related to its action, including the Order's inexplicable failure to accurately state the capacity of J.H. Campbell, the lack of awareness as to the operational status of Unit 2, the understatement of resources Consumers acquired to replace J.H. Campbell, and the omission of any reference to the reliability analysis undertaken by the State.

vi. The Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate

Even accepting the Order's contention that there exists a capacity shortfall in MISO, it does not follow that commanding the continued operation of J.H. Campbell is the best or even an appropriate means of alleviating the shortfall. The Order does not assert that there is a local problem on the grid that only J.H. Campbell can solve. In this respect, the Order departs markedly from past uses of section 202(c) and from the Department's regulations implementing section 202(c), which state that: "Actions under this authority are envisioned as meeting a specific inadequate power supply situation."[127]

Rather, the emergency that the Order purports to identify – "potential tight reserve margins" – is one that spans the entire fifteen-state MISO region and one

[127] 10 C.F.R. § 205.371.

that could presumably be addressed by any number of actions across MISO. And, given that J.H. Campbell amounts to well less than 1% of generation capacity in MISO, there likely were options available that would have had a much greater impact on the overall balance of supply and demand. Further, because J.H. Campbell is an over 60-year-old facility in a largely degraded operational state, there presumably were alternative actions available that could have met the purported need with higher levels of reliability.

Yet the Order does not acknowledge any alternatives or explain whether less burdensome measures were exhausted before taking this action. The question of whether alternative measures could have been used to address the "emergency" is made more challenging by the fact that the Order never quantifies the extent of the emergency it purports to identify within MISO. But that omission merely highlights rather than excuses the deficiencies of the Order.

One possible alternative may have been demand-side measures. The Department's regulations require applicants seeking an order under section 202(c) to provide a "description of any conservation or load reduction actions that have been implemented . . . [and a] discussion of the achieved or expected results."[128] In the Yorktown case, the Department required Dominion to exhaust all demand response measures before dispatching the facility.[129] And yet here the Department failed to make any inquiry or even to consider whether demand-side measures could have

[128] 10 C.F.R. § 205.373.
[129] *See* DOE Order No. 202-17-4 (Sept. 14, 2017) ("PJM and Dominion shall exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Unit 1 or Yorktown Unit 2.")

addressed the purported emergency. Similarly, the Department's regulations require applicants to describe their efforts made to obtain additional power through third parties.[130] But again, the Department failed to consider whether MISO could alleviate the purported emergency through access to external resources.

D. The Department's Direction that MISO Operate J.H. Campbell Using "Economic" Dispatch Is Inconsistent with its Authority under Section 202(c).

The Department's Order directs MISO to "take every step to employ economic dispatch of the Campbell Plant."[131] The Order indicates that the use of economic dispatch is intended to "minimize cost to ratepayers."[132] However, this mandate to MISO exceeds the authority provided by section 202(c). Nor is the use of economic dispatch likely to serve the public interest.

The Order does not define "economic dispatch" or specify how it intends MISO to dispatch the units. In the Energy Policy Act of 2005, Congress adopted a definition of "economic dispatch" that generally conforms to accepted use: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[133] Drawing on this statutory definition, FERC issued a 2006 report, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations,* that provides a useful explanation of the 2-step process that

[130] 10 C.F.R. § 205.373(h).
[131] Order at 2 (Ordering Paragraph A)
[132] *Id.*
[133] *See* section 1234(b) of the Energy Policy Act of 2005, 42 U.S.C. § 16432(b);

regions have, in practice, adopted to implement economic dispatch.[134] This process includes (1) *day ahead unit commitment*, in which grid operators commit generators to be online in the subsequent 24-hour period, determined based on which generators will be most economic, taking into account each unit's physical operating characteristics, and (2) *unit dispatch*, in which grid operators dispatch committed resources at specified levels, in real-time, determined based on what set of units will minimize total system costs, given actual load, generation, and transmission conditions and constraints.[135]

Section 202(c) authorizes DOE to direct certain actions during emergency conditions. As relevant here, section 202(c)(1) provides DOE with "authority . . . to require by order . . . such generation . . . of electric energy as in its judgment will *best meet the emergency* and serve the public interest." In other words, DOE's power extends only to ordering actions that meet the emergency that the Department has identified.

But economic dispatch is not a rational response to the types of emergencies that section 202(c) authorizes DOE to address. Nor would economic dispatch be a rational approach to addressing the circumstance that DOE is purporting to address with its order—a potential capacity shortfall—if that were within its authority under section 202(c). In fact, DOE has made no effort to explain why economic dispatch is a rational remedy here, — let alone the best means of meeting the "emergency" that it

[134] FERC, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations* (July 31, 2006), https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.
[135] *Id.* at 5-6.

has identified. And, unlike prior Orders, here DOE acted on its own motion without a request or input of MISO and so cannot rely on the expertise of the cognizant grid operator or operating utility requesting a specific remedy to justify the appropriateness of economic dispatch.[136]

i. Economic dispatch is not a rational response to a shortage of electric energy

Economic dispatch is the standard procedure by which operators (such as MISO) operate the grid. However, outside of normal operations, including during emergency conditions, generation units may be selected "out of merit order" as necessary to ensure that generation and load are balanced. Operating a unit pursuant to economic dispatch is, necessarily, inconsistent with operating the unit in a manner designed to address an emergency, such as a shortage of electric energy. If a unit would be dispatched under purely economic conditions, but electric demand can alternatively be met with other existing supply (or demand response) resources, that unit is *not* necessary to meet the emergency. However, if the unit would, in fact, be needed to address a shortage, it should be dispatched regardless of whether its offer price is above or below the market-clearing price. In other words, economic dispatch is not a dispatch rule that is reasonably tailored to ensure that the unit addresses a shortage of electric energy.

[136] *See* DOE Order No. 202-18-1 at 4 (The statute requires only that the Secretary use his or her best judgment to meet the emergency and serve the public interest. In this situation, the expertise of the applicant was an important factor. The Department received an application from PJM, which . . . holds the highest-level, federally-regulated reliability responsibilities for the system it manages.), https://www.energy.gov/sites/prod/files/2017/11/f46/Summary%20of%20Findings%20Order%20No.%202-18-1.pdf.

Prior DOE orders have contained significant operating constraints to satisfy this statutory requirement. Orders have specified that units subject to a section 202(c) order should only run in specific emergency alert conditions — specific conditions in which grid operators have exhausted the capacity of other available generators, imports, and voluntary demand response, and failure to call on additional generation will risk involuntary load shed.[137] Similarly, in its order to delay retirement of the Yorktown plant, DOE recognized that dispatch of the units must be constrained, that continued operation of the units under the standard methodologies used by the local utility (Dominion Energy Virginia) and grid operator (PJM) would not be appropriate, and that Dominion and PJM must exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2.[138] Similarly, in the case of its 2005 District of Columbia Department of Public Service order, the Department directed Mirant to maintain its facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[139] And in its 2017 order regarding GRDA's Grand River Energy Center

[137] DOE Order No. 202-21-1 (authorizing operation only during Energy Emergency Alert Level 2 or Level 3); DOE Order No. 202-21-2 (authorizing operation only during Energy Emergency Alert Level 2 or higher); DOE Order 202-22-1 (same); DOE Order No. 202-22-3 (same); DOE Order No. 202-22-4 (same).

[138] DOE Order No. 202-17-2 (providing that Yorktown units 1 and 2 may be dispatched "only when called upon to address reliability needs" and directing PJM and Dominion Energy Virginia "to provide the dispatch methodology to the Department upon implementation, and to report all dates on which Yorktown Units 1 and 2 are operated"); DOE Order No. 202-18-1 at 3 (relying on the fact that DOE "require[d] PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2").

[139] DOE Order No. 202-05-3 (Dec. 20, 2005), District of Columbia Public Service Commission at 10 – 11.

Unit 1, the Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[140] DOE's Order contains no such constraints, and it fails to explain or justify such deviation from consistent past practice.

ii. Economic dispatch is an arbitrary response to any alleged capacity shortage

Indeed, even on DOE's own terms, the justification for the Order does not support ordering J.H. Campbell to operate whenever MISO's economic dispatch rules would select it to operate. The Order points specifically to questions about the sufficiency of electric *capacity* and the ability of MISO to meet load during periods of high demand and low resource output over the next 90 days as the basis for its emergency determination.[141] For example, the Order points to NERC's 2025 Summer Reliability Assessment, and specifically to the finding that "MISO is at elevated risk of operating reserve shortfalls *during periods of high demand and low resource output*."[142] The order repeatedly raises concern about the risk of "*capacity* shortfall for MISO," the extent to which *capacity* of certain generating resources have retired or may retire, and that MISOs' *capacity* market auction (the Planning Resource Auction Results for Planning Year 2025-26) "reinforce the need to increase *capacity*."[143] Dispatch of J.H. Campbell at any time other than a specifically identified operating reserve shortfall (e.g., a concrete expected supply/demand imbalance)—let

[140] DOE Order No. 202-17-1 at 2.
[141] Order at 1-2
[142] Order at 1 (emphasis added).
[143] Order at 1-2.

alone dispatch whenever the plant would be called upon by MISO's economic dispatch algorithm—is *not* necessary to address the type of emergency that the DOE order identifies. Even if the order sufficiently justified retention of J.H. Campbell as a capacity resource (which it does not for the reasons outlined above), it would not follow that J.H. Campbell's electric *energy* is needed to address the identified emergency. Given the nature of the alleged emergency identified in the Order, no dispatch from J.H. Campbell should be necessary unless and until called upon by MISO expressly to address an emergency purpose.

iii. "Economic dispatch" is not in the public interest in this case

Section 202(c) also requires that DOE determine that a given remedy is in the public interest.[144] The public interest determination is not an independent or sufficient criteria to order any particular action. Rather, Congress's use of the conjunctive "and" in section 202(c)(1) clearly prohibits DOE from ordering actions that the Department believes will advance the public interest if those actions exceed what is needed to address the identified emergency. In fact, DOE acknowledged this limit on its authority in its order denying rehearing of its order directing the retention of the Yorktown power plant.[145] Therefore, for the reasons explained above, economic dispatch is not appropriate even *if* DOE determines that it would advance the public interest.

However, DOE's vague direction to MISO to operate Campbell using "economic dispatch" will not further the public interest. DOE's order does not explain why it

[144] 16 USC § 824a (c)(1).
[145] DOE Order 202-18-1 at 4.

believes economic dispatch would be in the public interest, other than a general reference to "minimize[ing] cost to ratepayers." However, this justification fails for two reasons. First, the Order's reference to economic dispatch is ambiguous and leaves open the likelihood that Consumers will operate the facility even at times when its operation will have the effect of *increasing* costs to consumers. For example, Consumers is likely to commit J.H. Campbell into MISO's day ahead electricity market as a "must run" unit, rather than using Emergency commitment.[146] In other words, Consumers will operate the units at least at minimum load every day rather than when there is a forecasted shortfall (e.g., due to unexpected load, unit outage, or a natural disaster). In such circumstances, J.H. Campbell will run at its minimum operational level regardless of whether doing so is truly economic. As a result, DOE has not justified, and cannot be reasonably certain, that economic dispatch will "minimize cost to ratepayers" — its sole explanation for the operational profile it has directed MISO to adopt. In other words, DOE's ordering of economic dispatch in this case is arbitrary.

Moreover, by directing economic dispatch, rather than reserving J.H. Campbell for discrete supply shortages by committing it as Emergency status, DOE's order will result in the facility operating significantly more than necessary. Because J.H. Campbell is old, and because Consumers has been deferring maintenance in anticipation of its retirement, a significant step-up in operation caused by must-run commitment and economic dispatch will increase the likelihood that one or more

[146] *See* MISO Tariff, Section 39.2.5.b.xxvi (discussing Emergency Commitment Status).

units break, requiring costly maintenance to continue operating. Such repairs would likely further increase costs to ratepayers—costs that would be less likely to occur under an operational order better tailored to the emergency that DOE has identified. For example, DOE could have minimized the risk of ratepayer costs had it directed Consumers and MISO to commit (and ultimately dispatch) the facility only after analysis showing a likely near-term supply/demand imbalance or short-term emergency conditions (such as a heatwave, or the forced outage of a large generator or transmission line). The Order is arbitrary and capricious by ordering operation that risks increasing costs to ratepayers, the very outcome DOE has said it is looking to avoid.

Second, the Order fails to consider, let alone explain away, the fact that the State of Michigan has made an independent judgment that it would be in the best interest of ratepayers, the state, and the environment, to accept Consumers' proposal to retire J.H. Campbell. As explained above, the State of Michigan and MISO each went through robust processes to assess the need for J.H. Campbell (or lack thereof), as well as the economic and environmental impacts of its continued operation. The State of Michigan appears not to have been consulted on DOE's Order, notwithstanding the extensive process that it underwent to evaluate whether retirement would be in the public interest. Here, the public interest is best effectuated by respecting the Michigan's considered decision to approve the closure of J.H. Campbell plant, rather than to allow its near continuous operation at ratepayer expense.

Finally, for the reasons explained more fully below, the Order fails to consider the increased air and water pollution that will be caused by J.H. Campbell operating pursuant to economic dispatch instructions. DOE fails to even consider these harms, let alone weigh them against the (alleged) benefits of increased operation, in its determination that economic dispatch of the J.H. Campbell plant will further the public interest.

E. The Department failed to limit its remedy as required by 202(c)(2).

Section 202(c) imposes strict substantive limits on the Department's authority to issue emergency orders that may result in conflicts with any Federal, State, or local environmental law or regulation. Congress deliberately included these limitations to prevent section 202(c) from becoming a de facto exemption from environmental regulation. Here, DOE failed to comply with either of the statute's two express constraints and therefore acted unlawfully.

i. Section 202(c)(2) contains two distinct and binding legal constraints

Congress imposed two critical limitations on the scope of a DOE emergency order under section 202(c):

Temporal Constraint. First, DOE must "ensure that such order requires generation . . . of electric energy only during hours necessary to meet the emergency and serve the public interest."[147] Again, this is a conjunctive requirement such that both conditions—operation in a given hour must be necessary to meet the emergency

[147] 16 U.S.C. § 824a(c)(2).

and operation in a given hour must serve the public interest—must be satisfied.[148] Moreover, by referring to the "hours" necessary to meet the emergency, Congress placed a high burden on DOE to demonstrate that the remedy provided was narrowly tailored to the specifics of the emergency that the order is designed to address.

Environmental Constraint. Second, the Department must "ensure that such order . . ., to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts."[149]

The Department acknowledges that, "additional generation may result in a conflict with environmental standards and requirements" and so it is required to limit additional generation from J.H. Campbell. However, the Order then wholly fails to meet the acknowledged temporal and environmental constraints in the particular ordering conditions that it establishes.

ii. The Order violates Section 202(c)(2)'s temporal constraint

The Order states that its direction to Campbell is "limited in duration to align with the emergency circumstances."[150] But, in fact, DOE has directed the unit to operate for the entire statutory maximum of 90 days. And, as described in more detail *supra,* within that 90-day window, DOE has directed the use of "economic dispatch"—an operational direction that will likely result in Campbell operating at least at its

[148] DOE Order No. 202-18-1, 4(Nov. 6, 2017).
[149] 16 U.S.C. § 824a(c)(2).
[150] Order at 2.

minimum output level, and more likely at the maximum output Consumers Energy can manage, taking into account the state of the facility, continuously for the 90-day period—without providing any other temporal limitation on operations. In other words, the Order appears to assume, without explanation, that an emergency will exist in every hour over the entire 90-day period of the Order that Consumers happens to submit a bid into MISO's energy auction that is lower than the market-clearing price.[151] There is no reason to expect that this will actually be the case.

For these and all the reasons explained in section IV.C, the Order's direction that MISO dispatch J.H. Campbell economically is flatly inconsistent with section 202(c)'s requirement that emergency orders be limited to "only" those "hours" in which operation is necessary to meet the emergency. DOE cannot transform an hour-by-hour limitation into a blanket summer-season waiver through hand-waving at "elevated risk" of tight operating reserves and "*potential* electricity shortfalls."

DOE's failure to limit dispatch to discrete periods when the generation is needed to address the purported emergency renders the Order unlawful under the plain terms of § 202(c).

iii. The Order violates section 202(c)(2)'s environmental constraint

Section 202(c)(2) also requires DOE to ensure, "to the maximum extent practicable," that its orders (1) are consistent with applicable environmental laws and

[151] In fact, it is not clear that DOE will limit operation to 90 days. DOE is authorized to extend the Order beyond 90 days under section 202(c), 16 U.S.C. § 824a(c)(4)(A), and has made no representation that the "emergency" is likely to be resolved by the end of the 90-day period.

regulations and (2) "minimize any adverse environmental impacts." The Department makes no serious effort to comply with this mandate.

First, the Order contains no analysis of J.H. Campbell's environmental obligations. J.H. Campbell is subject to air pollution requirements limiting its emissions of SO_2, NO_x, particulate matter, and mercury, and mandates the use of pollution control equipment such as baghouses, dry sorbent injection, and activated carbon injection systems.[152] DOE does not reference these requirements, direct Consumers to optimize the use of pollution controls or avoid operation during air quality episodes (even if those episodes occur at a time when the marginal energy from J.H. Campbell is not needed to meet electric demand), or provide any guidance for how Consumers is to operate the facility in the event that these requirements would come in conflict with its ability to provide power at any given time. It does not clarify what steps Consumers Energy would have to take to ensure continued operation of pollution control equipment in the event such equipment malfunctioned during the 90-day period. Nor does it appear the Department consulted with the State of Michigan, including its environmental regulator, to identify mechanisms to allow J.H. Campbell to remain available in a way that would minimize conflicts with state environmental laws, which the State was uniquely positioned to advise on and which

[152] *See* Michigan Department of Environment, Great Lakes, and Energy, Renewable Operating Permit Issued to Consumers Energy, J.H. Campbell Generating Complex [J.H. Campbell ROP] (July 2, 2021), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal, and also accessible at https://www.egle.state.mi.us/aps/downloads/rop/pub_ntce/B2835/B2835%20FINAL%2007-01-21.pdf.

is required by section 103 of the Department of Energy Organization Act.[153] Instead, the Order offers only generic language about "compliance with applicable requirements… to the maximum extent feasible."

Second, the Order does not establish any operational criteria to "minimize any adverse environmental impacts" as required by section 202(c)(2). This requirement is in addition to the direction to minimize conflicts between operations and environmental requirements. It makes clear that Congress intended DOE to go beyond just avoiding regulatory conflicts but to proactively consider the environmental impact of its emergency orders. But DOE did not design its order to minimize environmental impacts of continued operation of J.H. Campbell. In fact, DOE's order runs directly contrary to the objective of minimizing environmental impacts by expressly directing MISO to operate J.H. Campbell on an "economic dispatch" basis. That instruction prioritizes low-cost dispatch irrespective of environmental impact.

F. The Order Violates NEPA.

Orders issued under section 202(c) are major federal actions subject to NEPA.[154] Such orders direct federal interventions that may affect environmental conditions. The direction to continue operation of J.H. Campbell is unquestionably a major action that significantly affects the environment. Continued operation of J.H. Campbell will result in significant increases of air and water pollution compared to a

[153] *See* 42 U.S.C. § 7113.
[154] 42 U.S.C. § 4336e(10) (defining a "major federal action" as one in which the agency carrying out such action determines subject to substantial Federal control and responsibility.").

scenario in which Campbell retired as planned.[155] In fact, the Order directly concedes this point, stating "the additional generation may result in a conflict with environmental standards and requirements."[156]

For any DOE action affecting the quality of the environment, DOE must comply with NEPA—including through issuance of an environmental impact statement, environmental assessment, categorical exclusion, or special environmental analysis.[157] DOE has not taken, or even initiated, any such action. As such, it is acting contrary to its own NEPA regulations and to its obligations under NEPA.

DOE has previously sought to comply with NEPA for section 202(c) orders through categorical exclusions or special environmental assessments. Neither have been undertaken in this instance. Moreover, neither would be applicable here.

DOE has previously pointed to categorical exclusion B4.4 for "power management activities." However, that categorical exclusion is applicable only "provided that the operations of generating projects would remain within normal operating limits." Here, the Order explicitly authorizes the J.H. Campbell plant to operate beyond its normal permitted limits. Consequently, neither categorical exclusion B4.4, nor any other available exclusion, applies.

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[155] *See* J.H. Campbell ROP, *supra* n. 152; State of Michigan Department of Environmental Quality, Authorization to Discharge Under the National Pollutant Discharge Elimination System, Permit No. MI0001422 (May 29, 2018), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal.
[156] Order at 2.
[157] *See* 10 C.F.R. § 1021.102(b).

More recently, DOE has, on certain occasions, relied on emergency provisions that can excuse agencies from preparing environmental documents before taking such actions,[158] and instead prepared after-the-fact Special Environmental Analyses in the event that an order results in a significant effect on the environment.[159] However, these instances involved sudden emergencies that provided DOE substantially less notice compared to the months or years of advance warning DOE received regarding J.H Campbell's scheduled retirement. In this case, DOE acted in response to circumstances known well in advance: the long-scheduled retirement of J.H. Campbell on May 31, 2025. Given considerable lead time, DOE had ample opportunity to prepare, at a minimum, an EA prior to issuing its Order. DOE's failure to initiate any environmental review thus lacks justification.

Moreover, there will be even less justification for a failure to initiate appropriate environmental review for any extension of the Order beyond the initial 90 days. Under section 202(c)(3), orders conflicting with environmental laws are strictly limited to 90 days but may be extended. However, such extension requires consultation with other federal agencies responsible for regulating or with expertise in such environmental impacts.[160] Any justification that NEPA can be sidestepped to

[158] *See* 10 C.F.R. § 1021.343(a); 40 C.F.R. § 1506.12.
[159] *See* DOE, Air Quality and Environmental Justice Memorandum (2021), https://www.energy.gov/sites/default/files/2022-01/sea-05-ercot-air-quality-and-ej-analysis-2021-07-21.pdf; DOE, Special Environmental Analysis for Actions Taken Under U.S Department of Energy Emergency Orders Regarding Operation of the Potomac River Generating Station in Alexandria Virginia (2006), https://www.energy.gov/sites/default/files/nepapub/nepa_documents/RedDont/SEA-04-2006.pdf
[160] 16 U.S.C. § 824a(c)(4)(B).

address an emergency need fades as DOE's orders extend beyond the initial 90-day period.

V. CONCLUSION

For the foregoing reasons, the Michigan Attorney General's request for rehearing should be granted.

Dana Nessel
Michigan Attorney General

Michael E. Moody

Digitally signed by Michael E. Moody
Date: 2025.06.18 16:14:42 -04'00'

Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

Dated: June 18, 2025

Attachment A

2025 NERC Summer Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025

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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is spans six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA*), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA*. Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's 2024 *State of Reliability* report

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

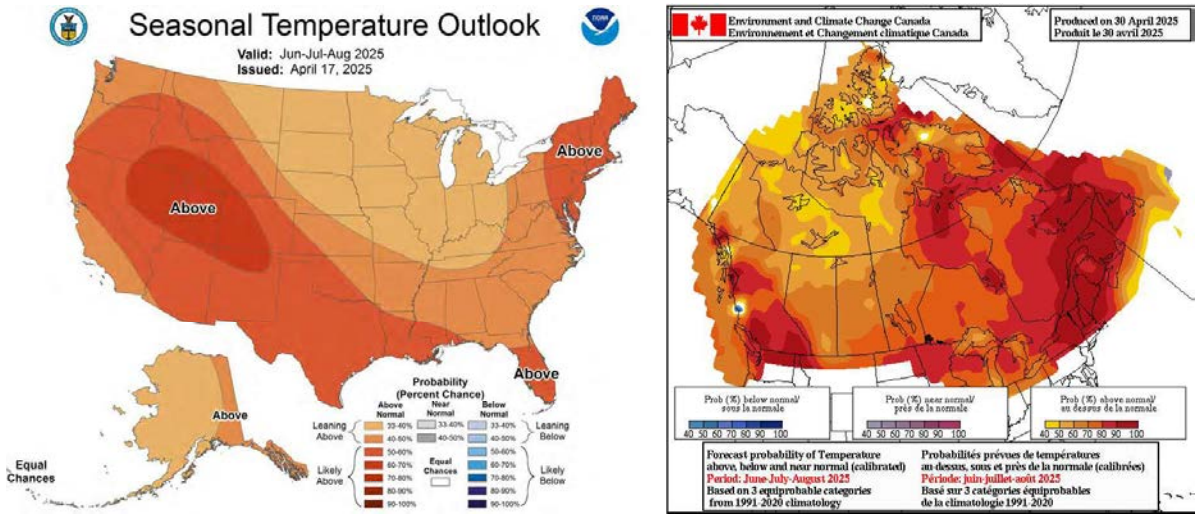


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 1.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 2.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

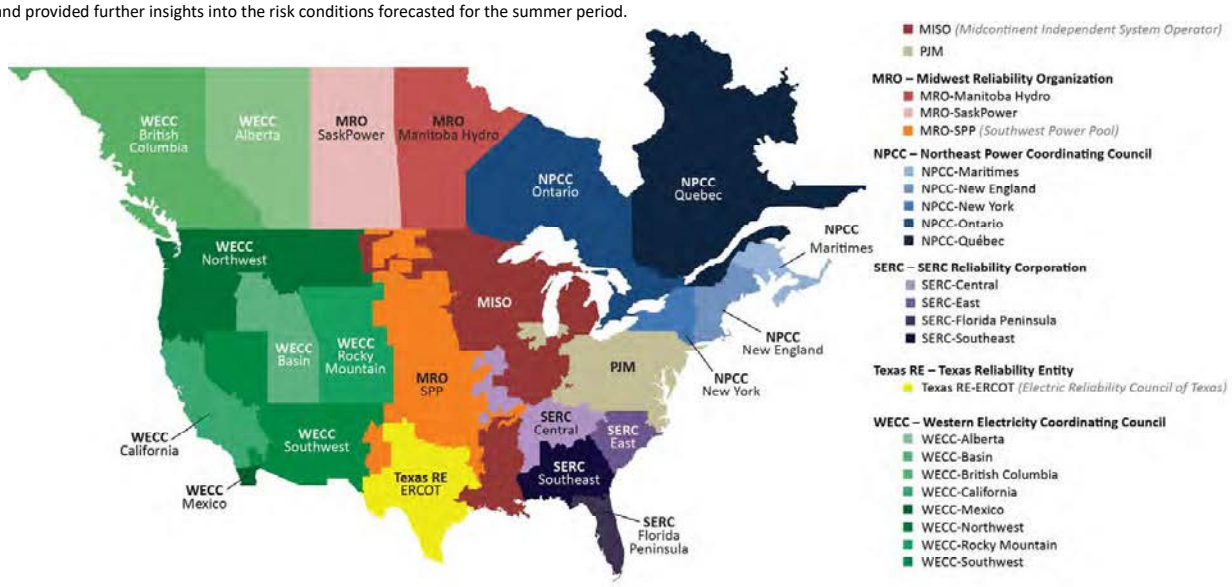
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central SERC-East SERC-Florida Peninsula SERC-Southeast	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



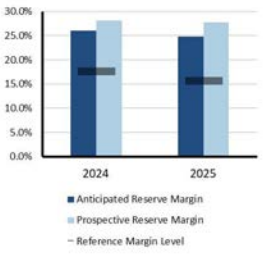
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

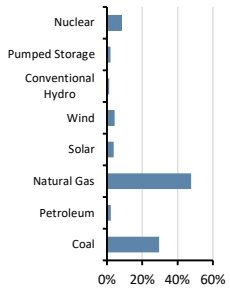
On-Peak Reserve Margin



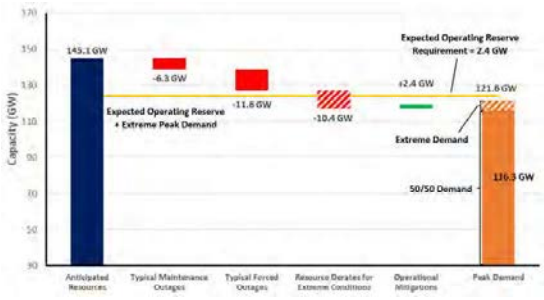
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions

MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

Highlights

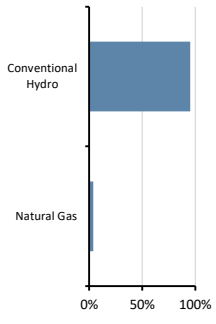
- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

Risk Scenario Summary

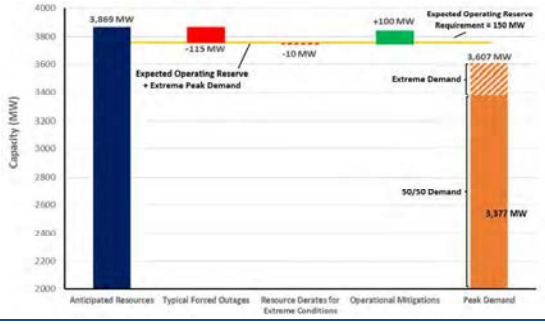
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

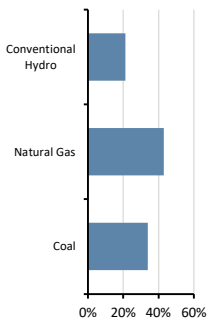
- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

Risk Scenario Summary

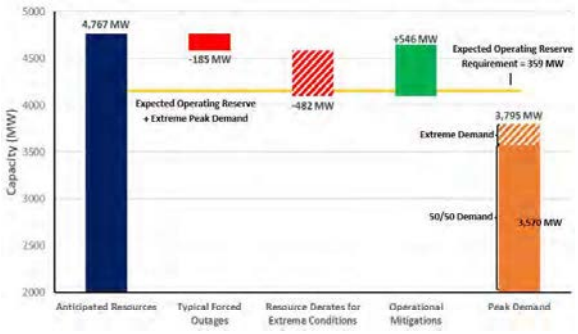
Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice

MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Highlights

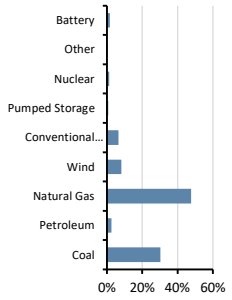
- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

Risk Scenario Summary

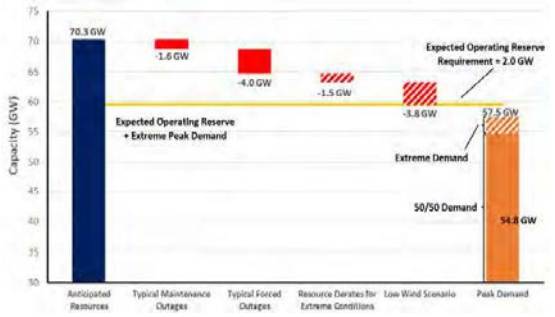
Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

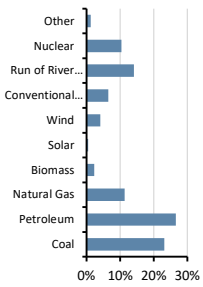
- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

Risk Scenario Summary

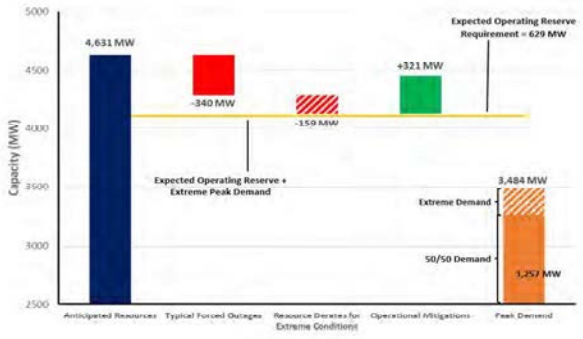
Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)

NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

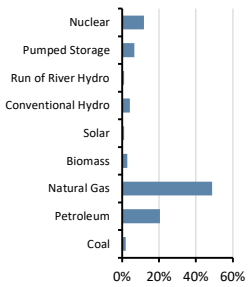
- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

On-Peak Reserve Margin

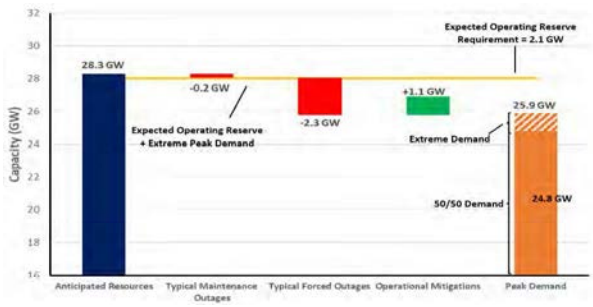
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

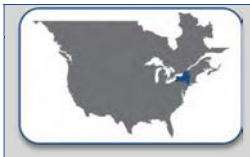
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

Highlights

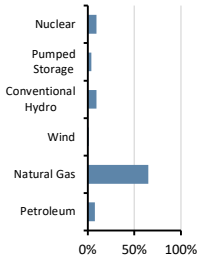
- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

Risk Scenario Summary

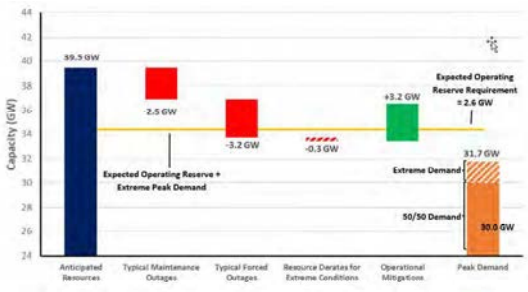
Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual

NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

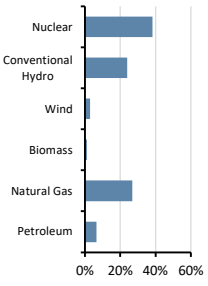
- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

Risk Scenario Summary

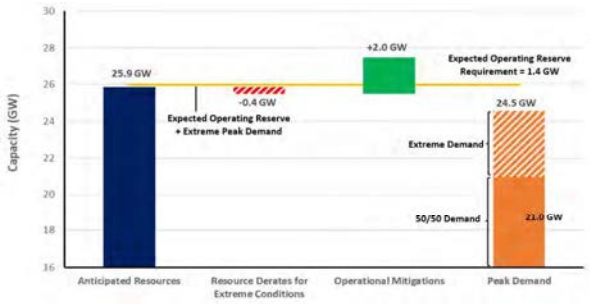
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.

NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

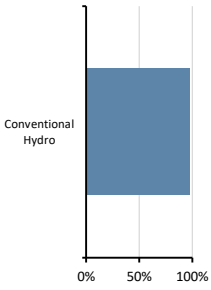
- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

Risk Scenario Summary

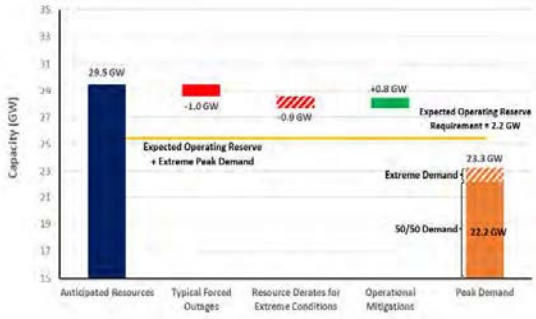
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.

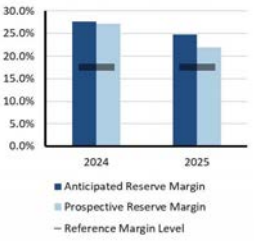
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

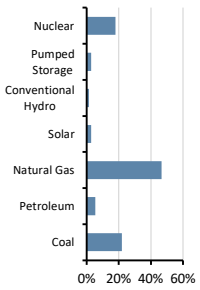
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

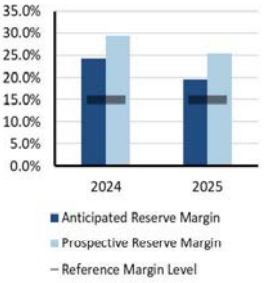
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

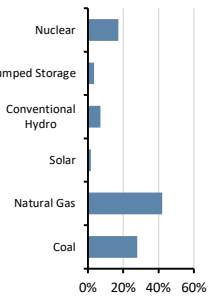
On-Peak Reserve Margin



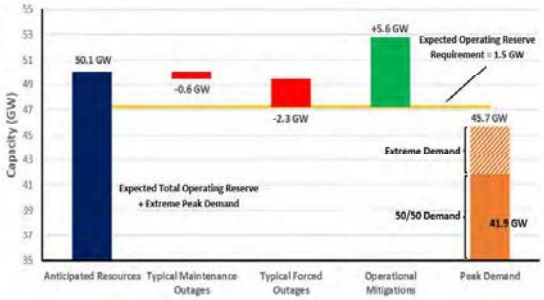
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures

SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

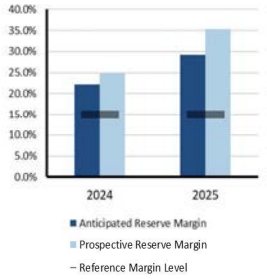
Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

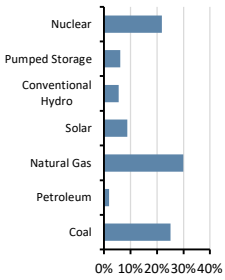
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures

SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

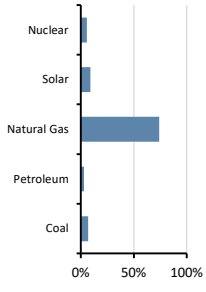
- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

On-Peak Reserve Margin

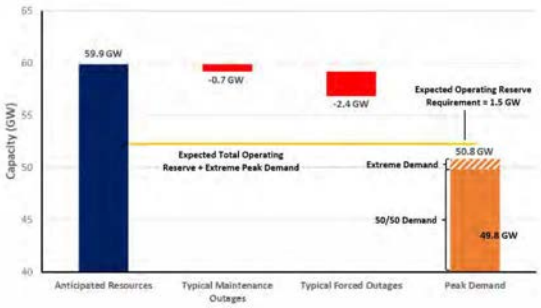
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

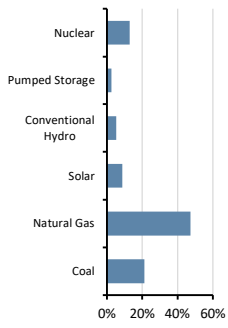
- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

On-Peak Reserve Margin

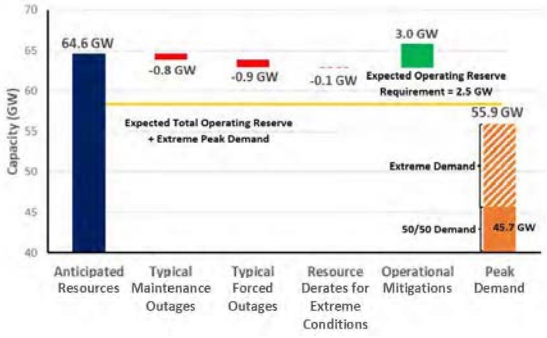
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

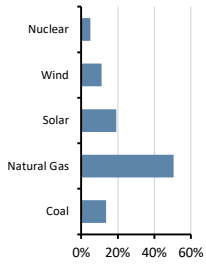
- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

Risk Scenario Summary

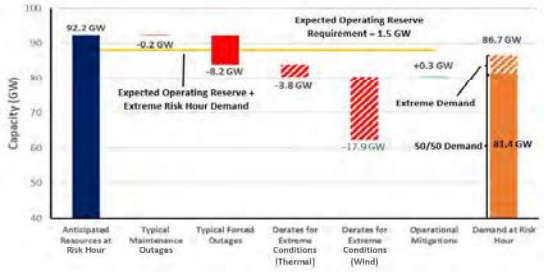
Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports

WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

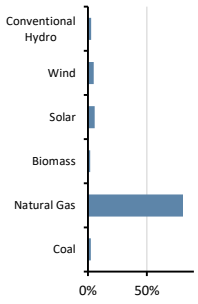
- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

Risk Scenario Summary

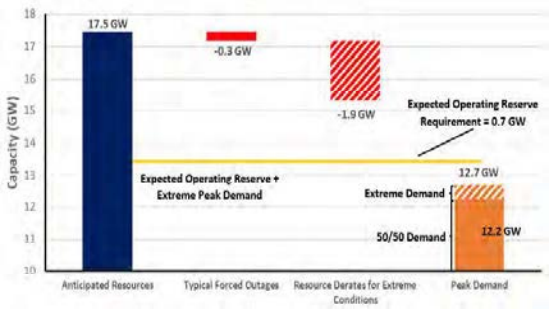
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

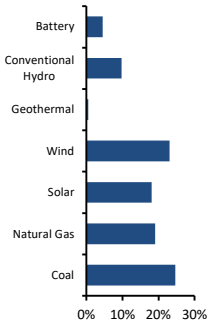
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios with imports.

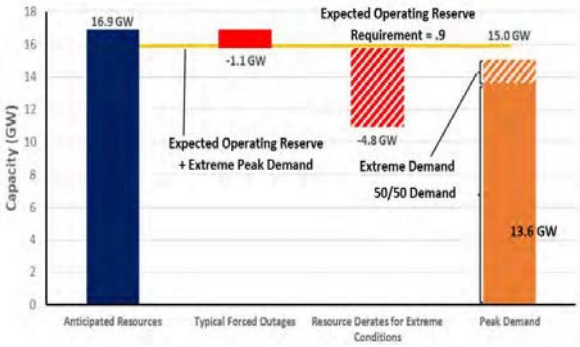
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

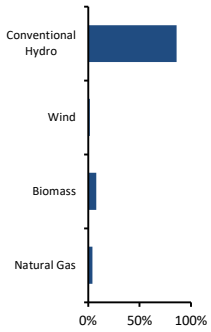
- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

Risk Scenario Summary

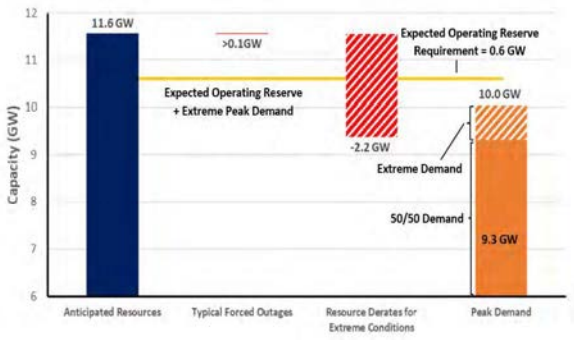
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-California

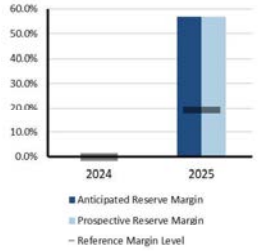
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

On-Peak Reserve Margin

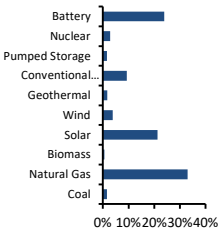
(Note: year comparison not available)



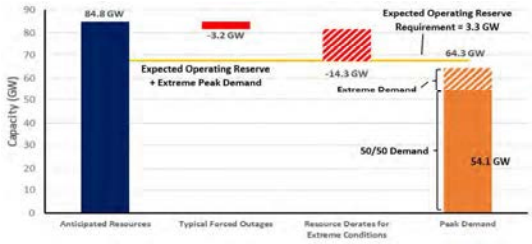
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages

WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

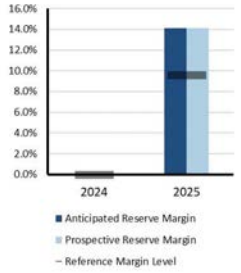
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

Risk Scenario Summary

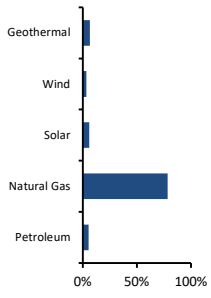
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

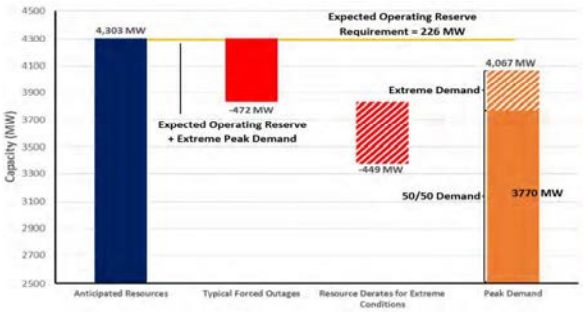
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

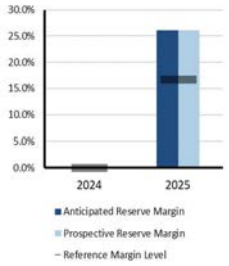
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

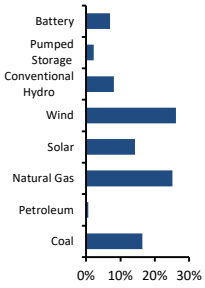
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

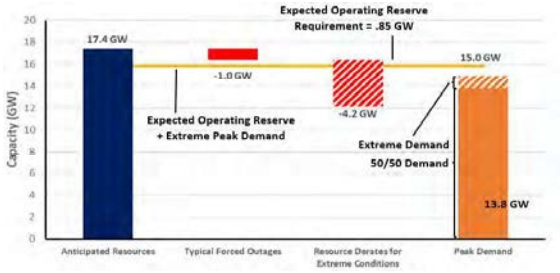


(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA*.

Highlights

- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

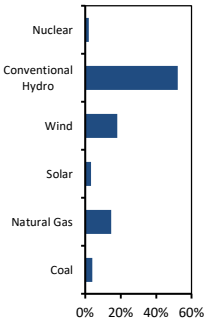
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

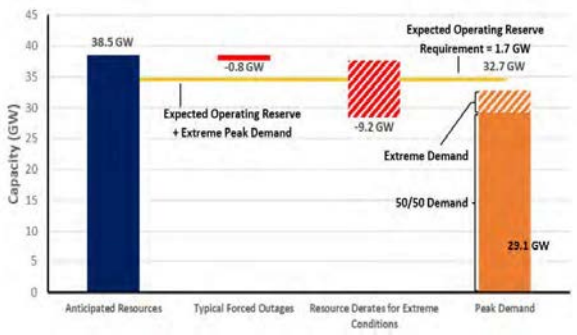
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

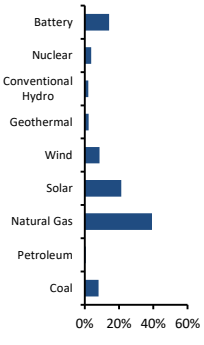
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

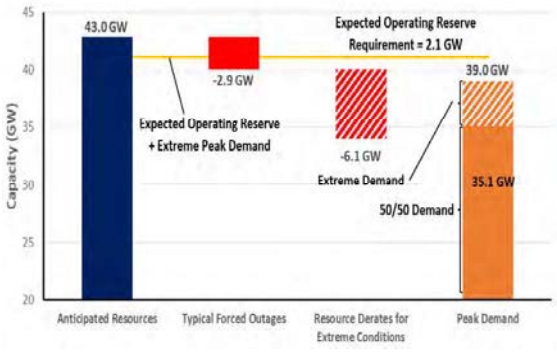
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[12] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[13] The summer season represents June–September and the winter season represents December–February.

[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the summer 2025 as shown in **Figure 4**.

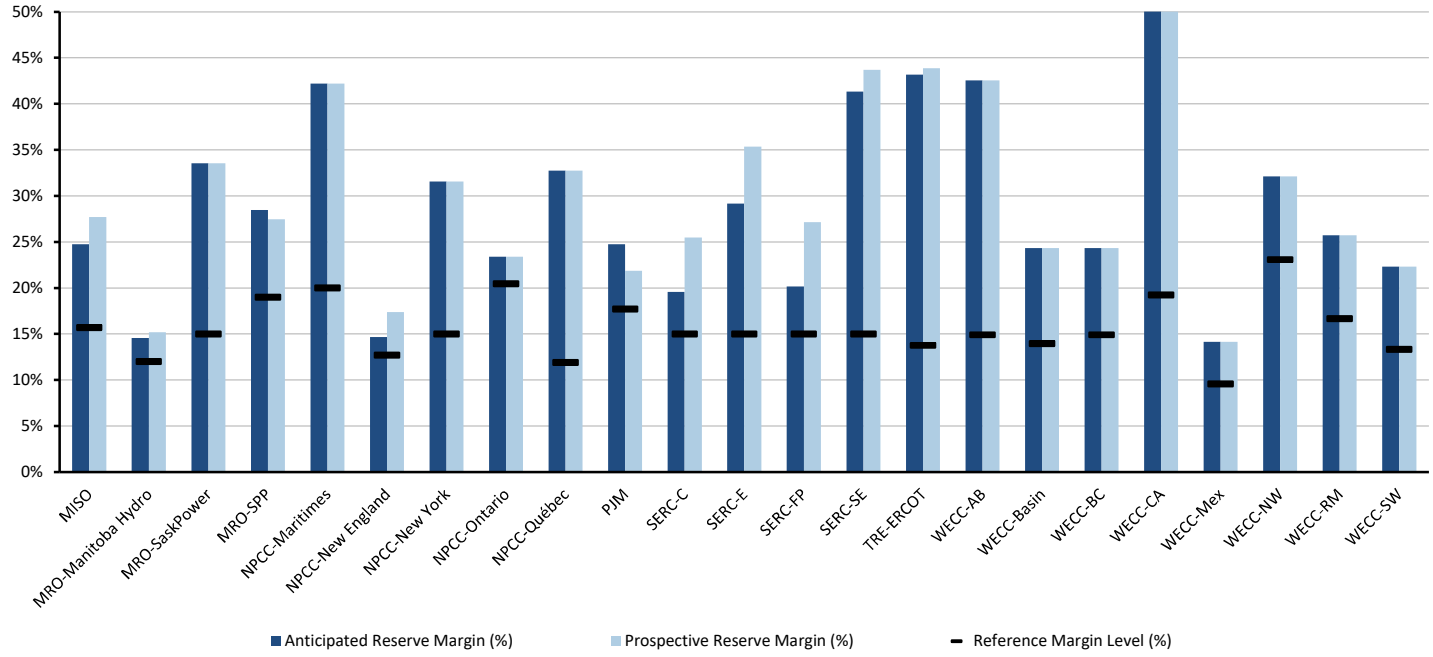


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

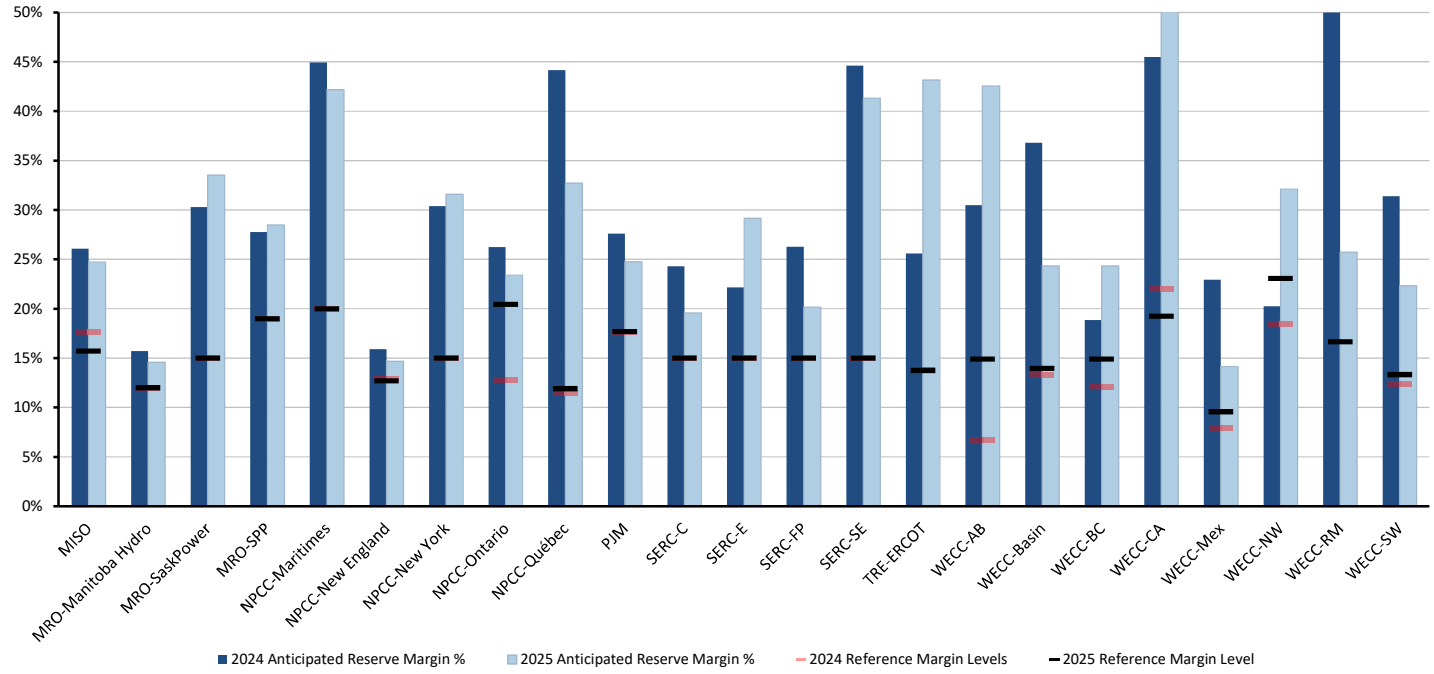


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

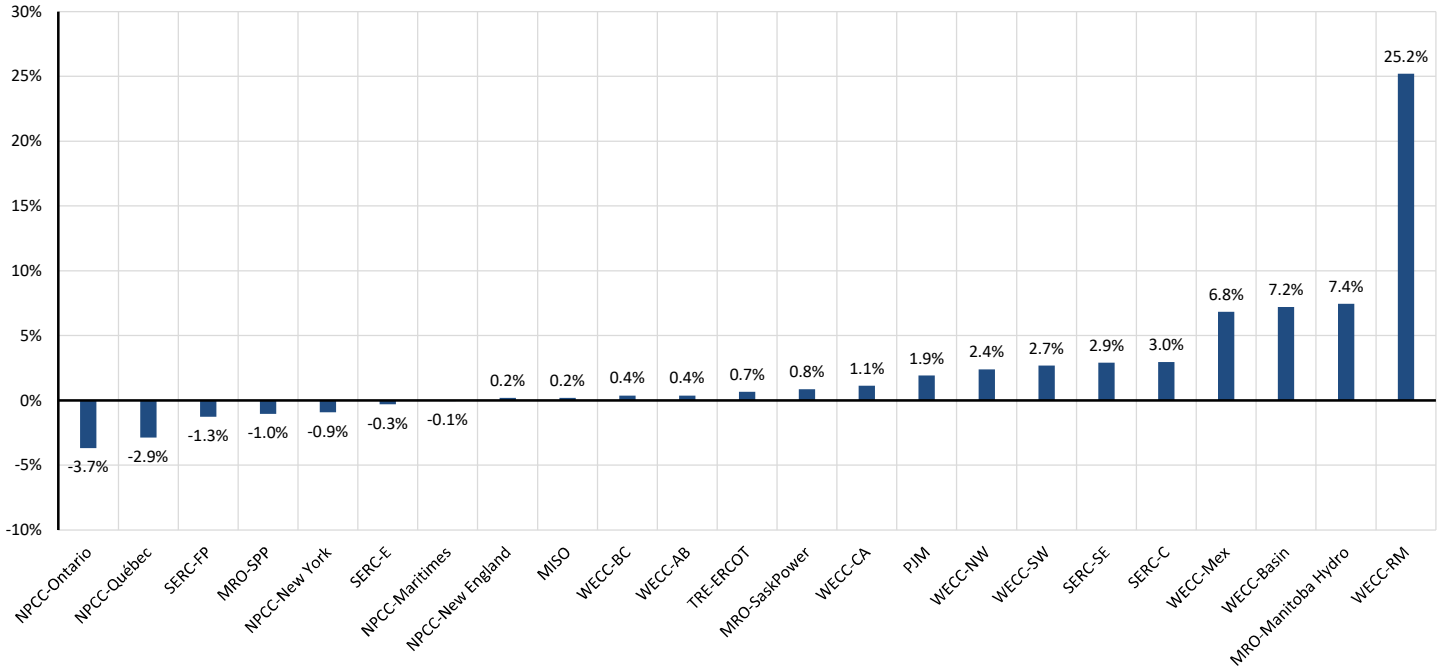


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	175,081	34,774	20%	142,014	86,170	61%	101,959	65,290	64%	36,311	32,298	89%

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta's demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.
[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2024 SRA*.
[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.
*Values include both maintenance and forced outages.
**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Attachment B

MISO 2025 PRA Report

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…

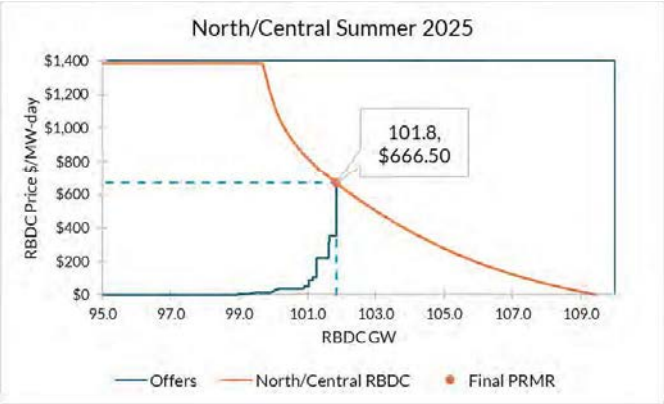
- Delivers competitive prices aligned with seasonal risks and tightening surplus
  - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
  - Clears capacity above target Planning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

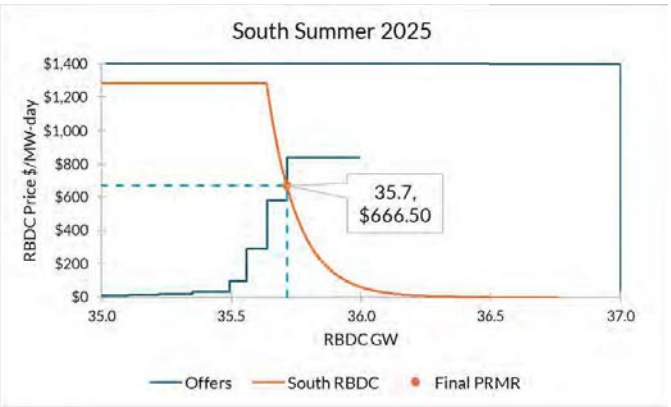
Why it Matters

- 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

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

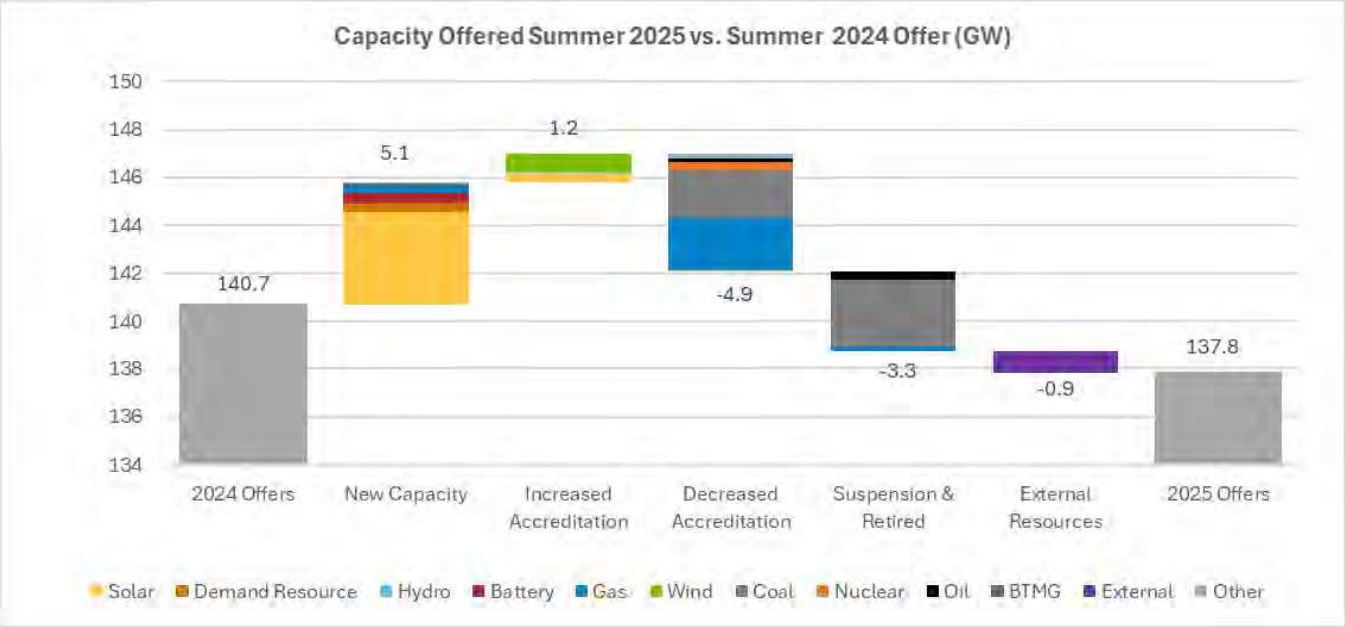
- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

	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

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

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

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

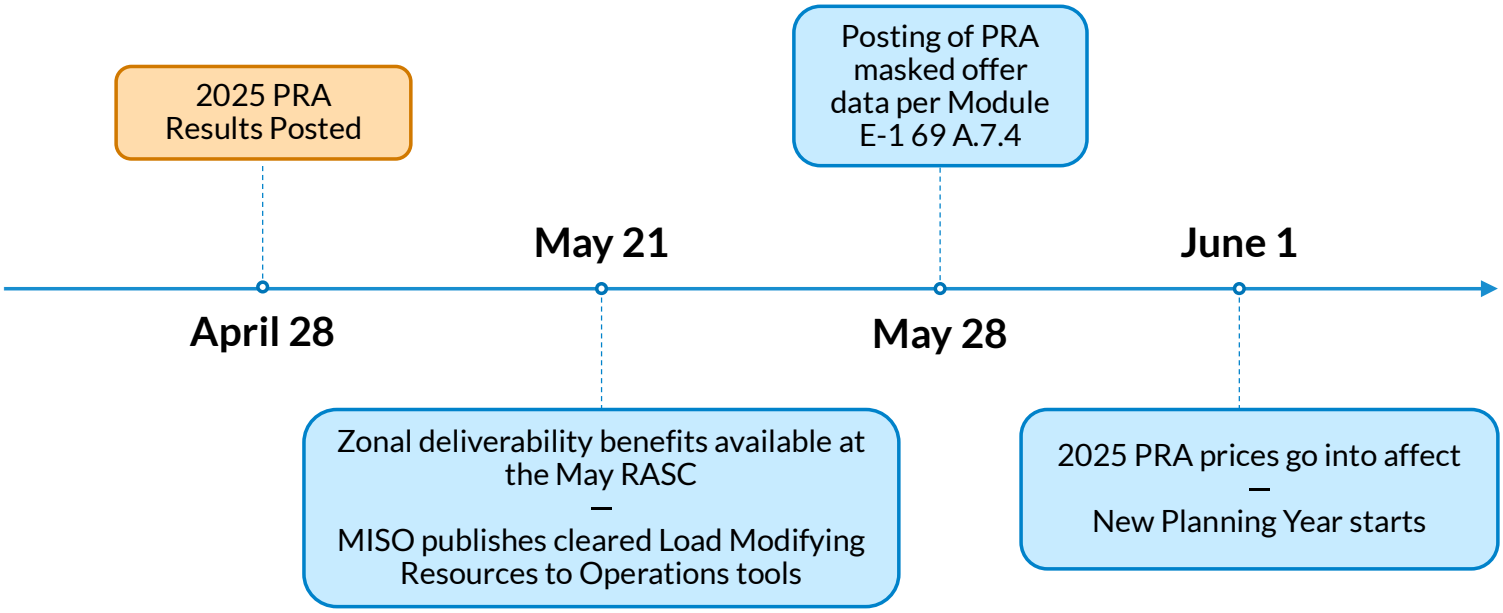
- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025)*
- ✓ Approved over $30 billion in new transmission 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

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

Next Steps


2025 PRA Results Posted
Posting of PRA masked offer data per Module E-1 69 A.7.4
April 28
May 21
May 28
June 1
Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools
2025 PRA prices go into affect
—
New Planning Year starts

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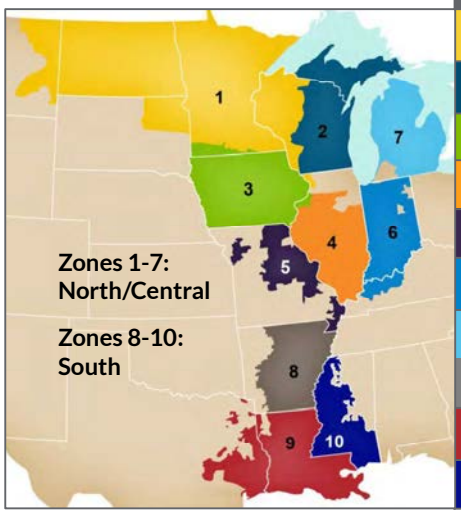
Acronyms

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

2025 PRA Results

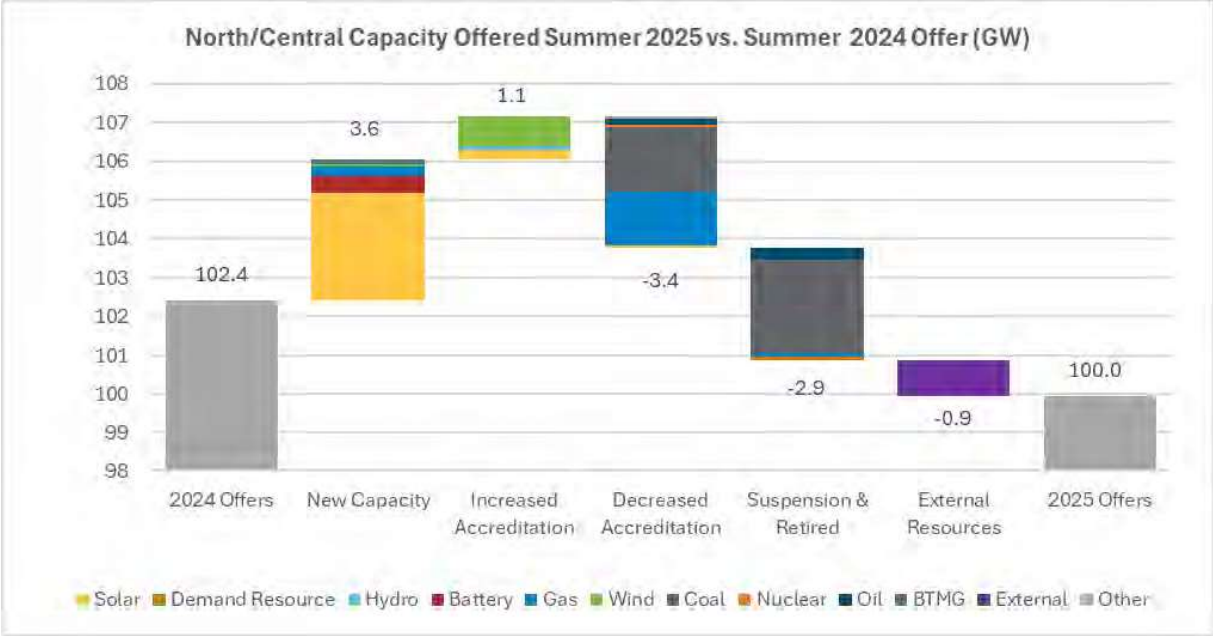
MISO Resource Adequacy Zones



	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	$666.50	$91.60	$33.20	$69.88
2				
3				
4				
5				
6				
7				
8		$74.09		
9				
10				

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

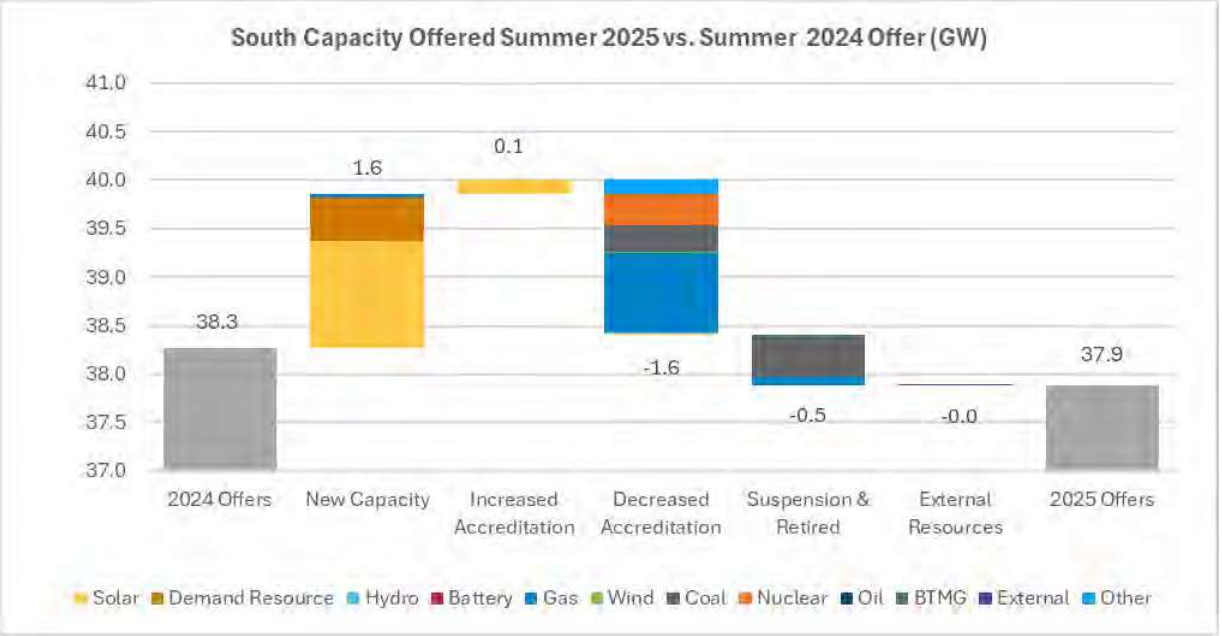
For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



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

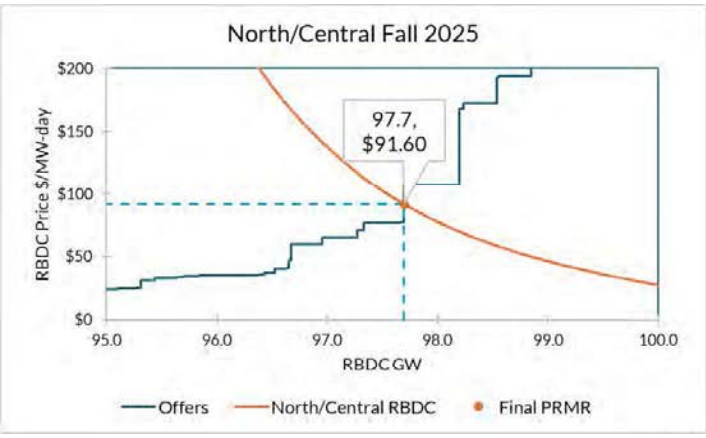
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

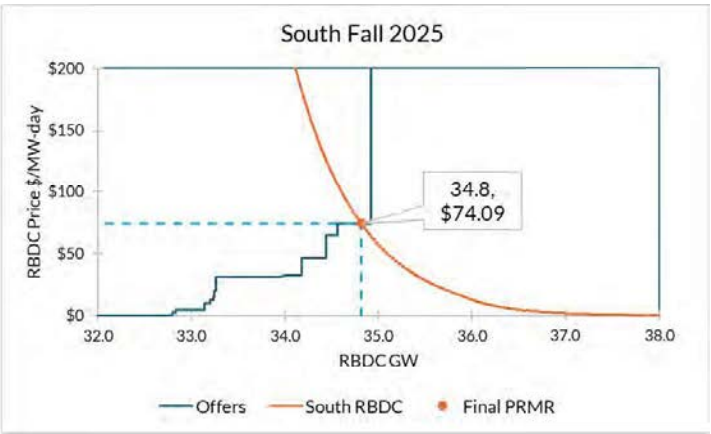
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



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

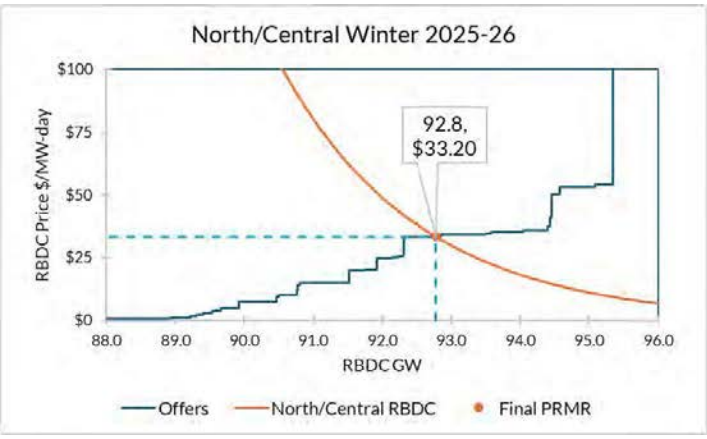
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

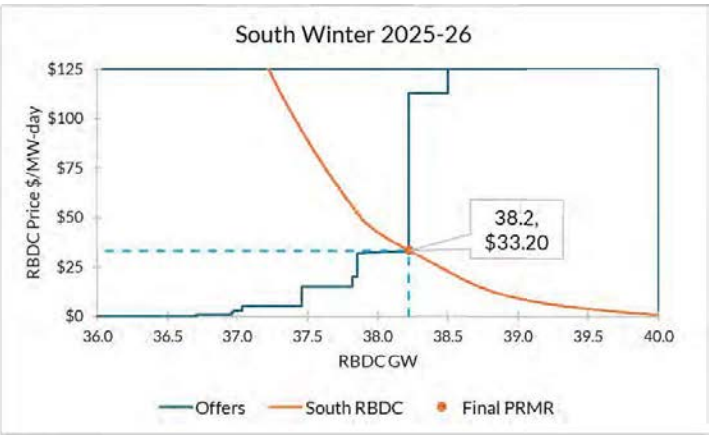




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
  - ACP for North subregion is $91.60, and $74.09 South subregion
  - A marginal 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%

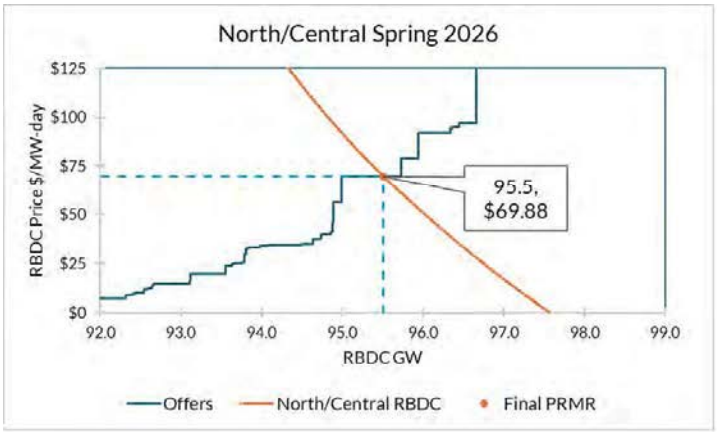
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices





- 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

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

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

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

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

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

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

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

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

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

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
Fall 2025	$91.60							$74.09			$83.24-$91.60

- 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

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

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

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

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

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

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

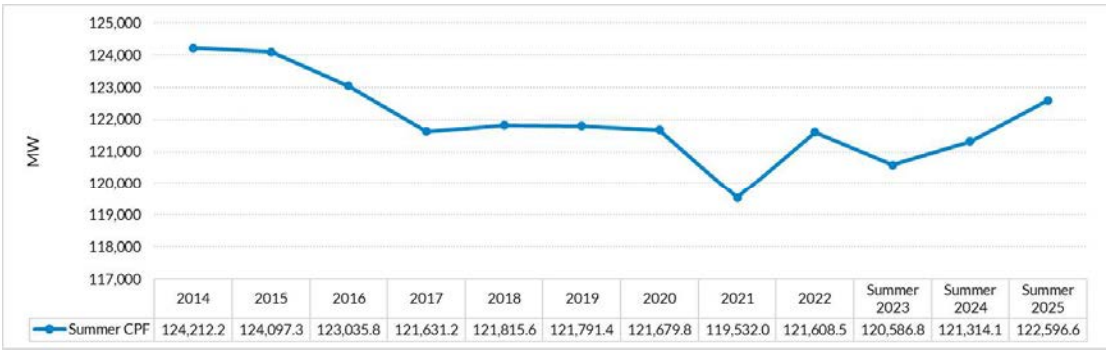
2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)

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

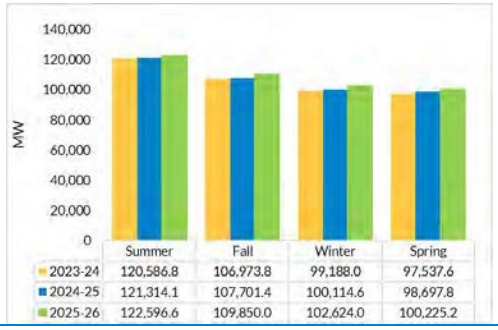
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

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

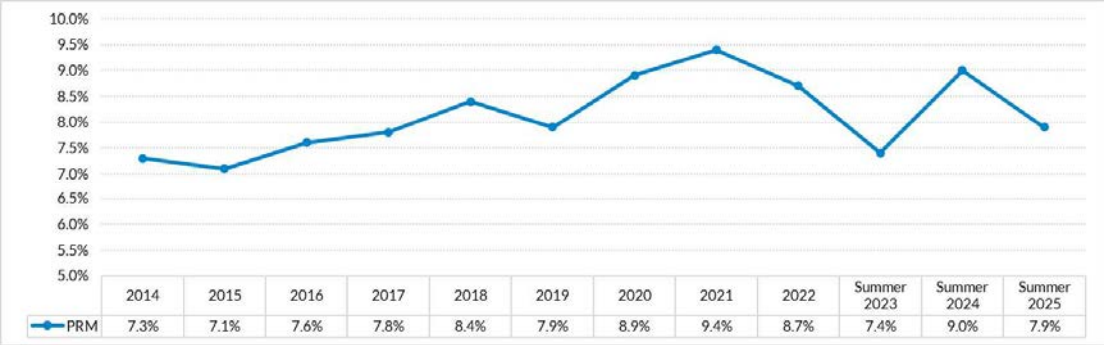


	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

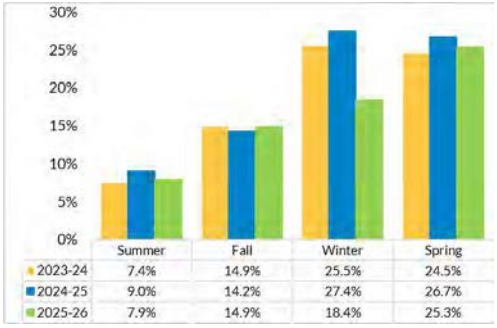
PRMR: Planning Reserve Margin Requirement

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

Planning Reserve Margin (%)

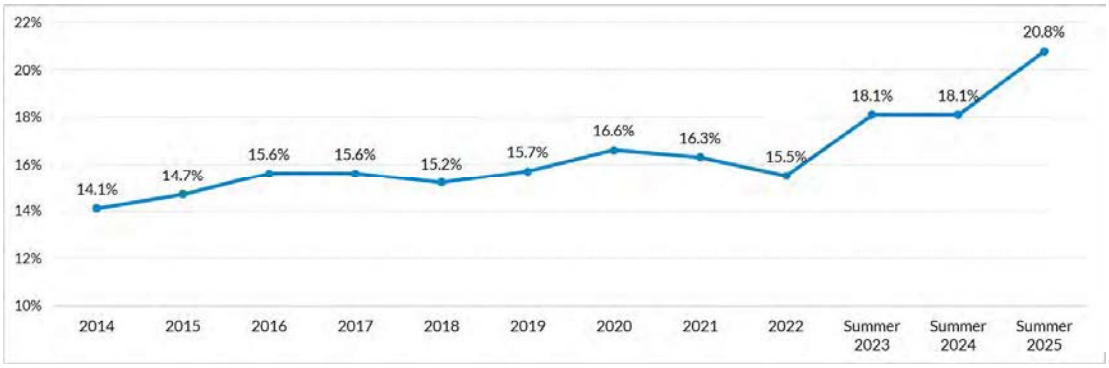


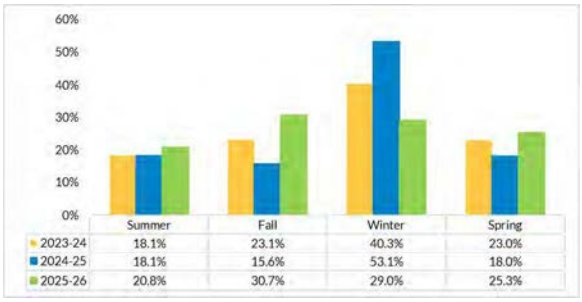
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	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 (%)





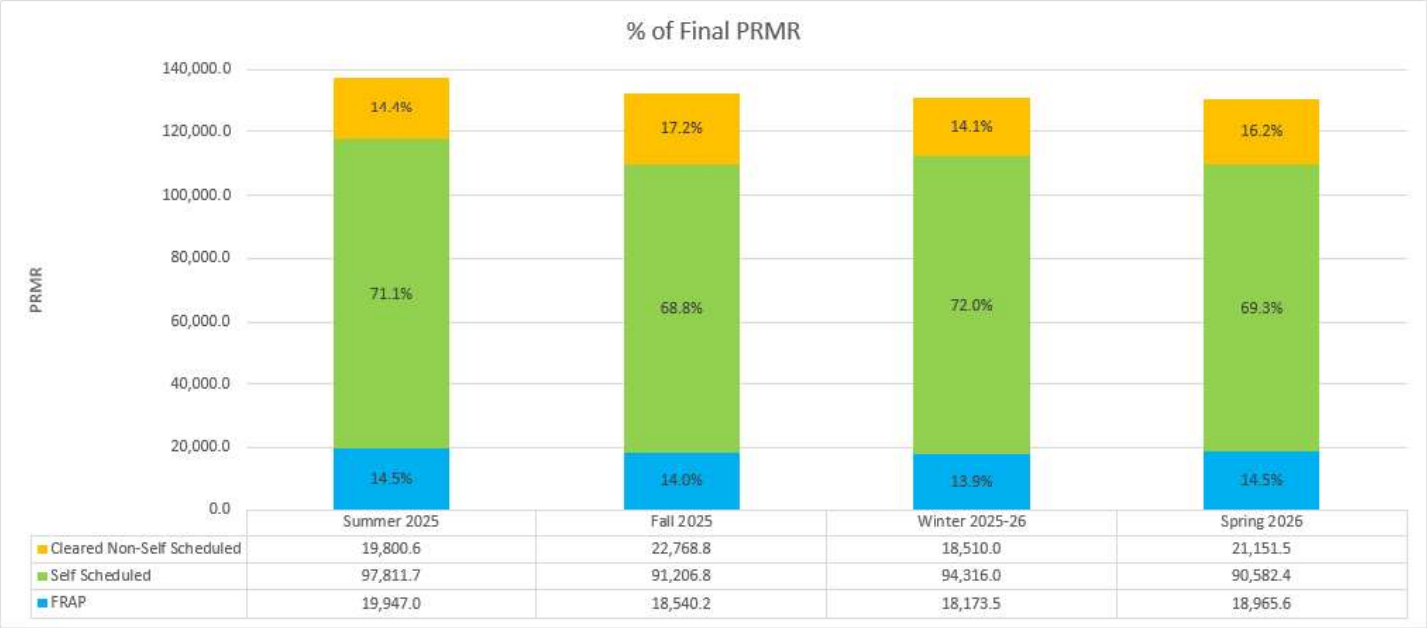
	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%
2025-26	20.8%	30.7%	29.0%	25.3%

- 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

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

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

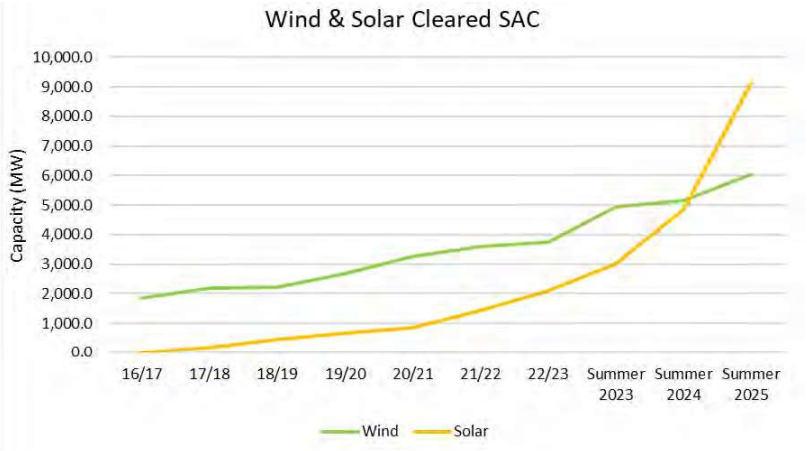


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

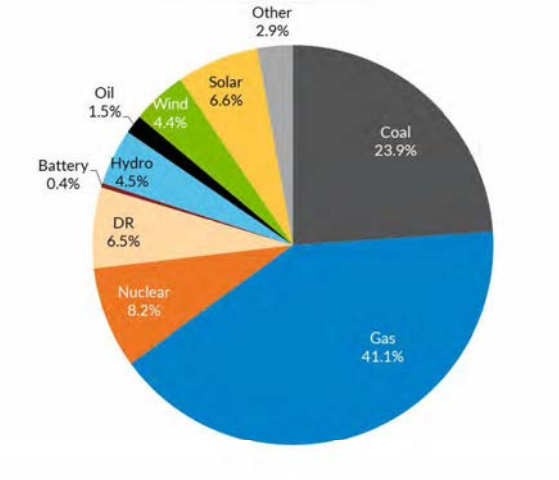
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 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

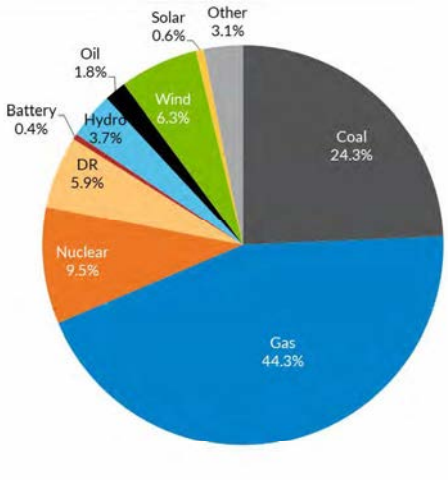
Summer 2025



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

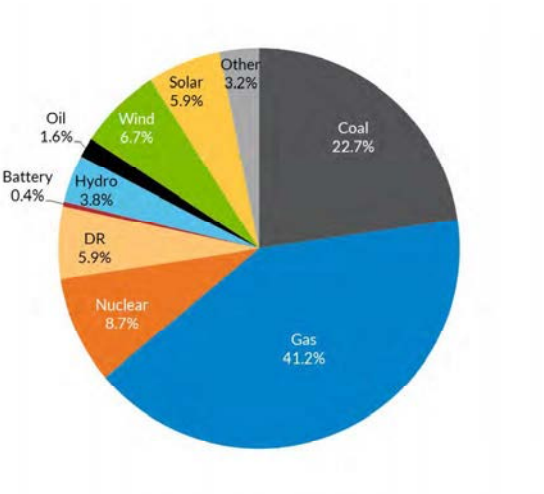


PRMR: Planning Reserve Margin Requirement

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

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

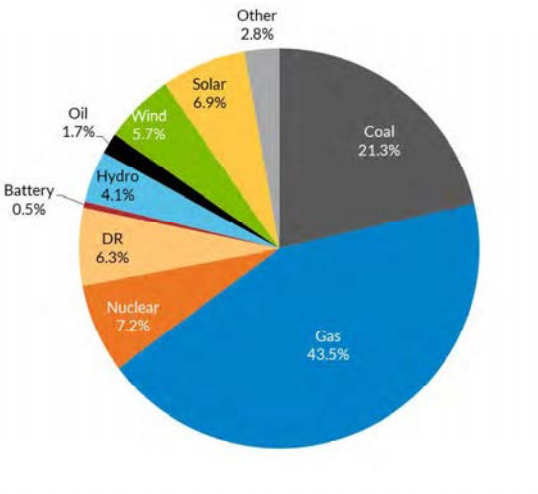
Fall 2025



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

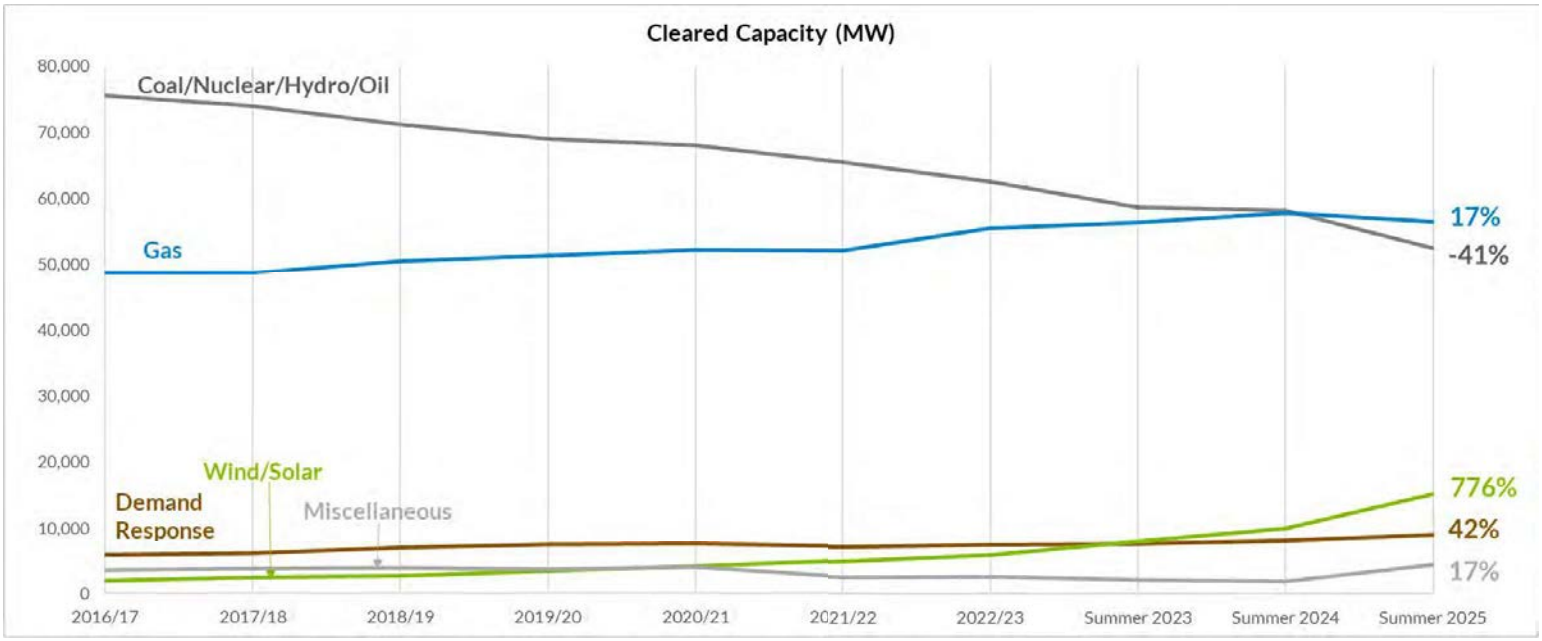
Spring 2026



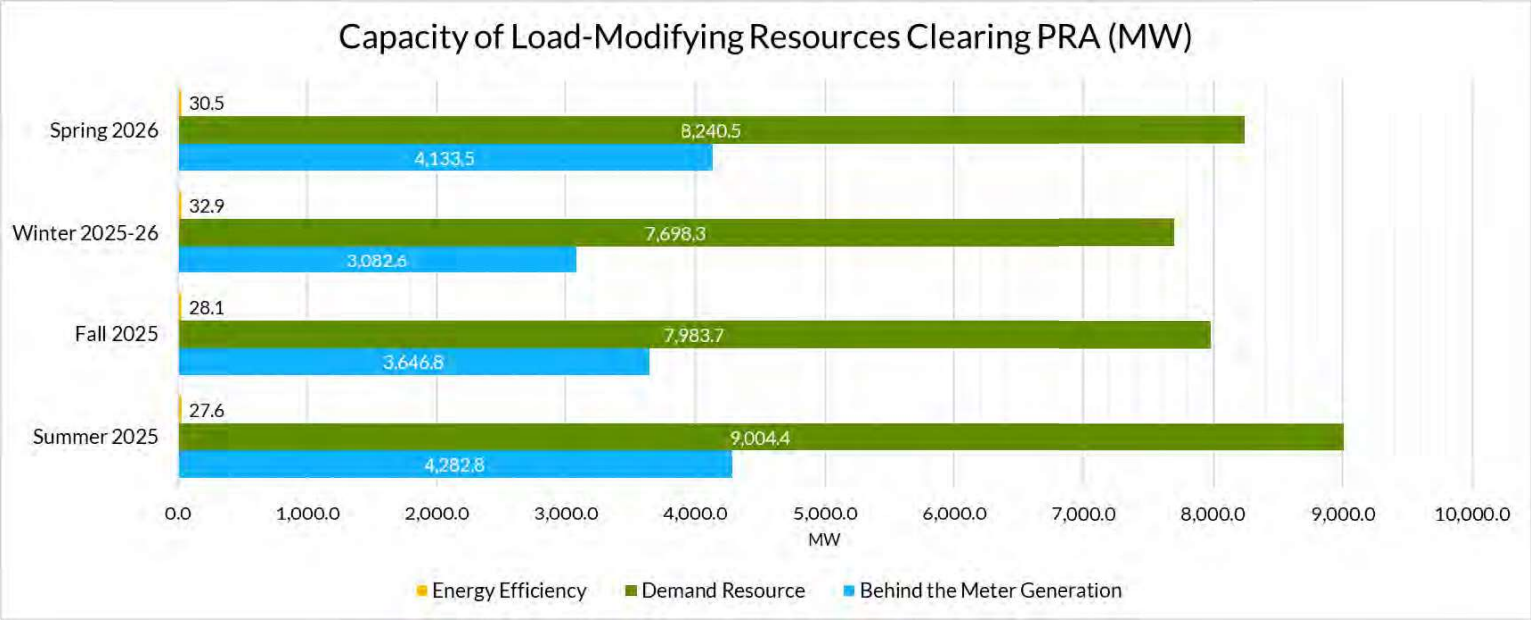
PRMR: Planning Reserve Margin Requirement

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

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/

Attachment C

Collection of MISO Attachment Y materials

Consumers Energy
Count on Us®

A CMS Energy Company

Timothy J. Sparks, P.E.
Vice President Electric Grid Integration

VIA Electronic Mail

December 14,2021

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

Re: Suspension of Campbell Units 1, 2 & 3

Dear Mr. Witmeier:

Consumers Energy Company ("Company") hereby provides notice to the Midcontinent Independent System Operator, Inc. ("MISO") that it intends to suspend Campbell Units 1, 2 and 3 effective June 1, 2025. Attached is the notice of such intent in accordance with Section 38.2.7 and Attachment Y of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

Campbell Unit 3 is jointly owned by the Company (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that, pursuant to the relevant Operating Agreements, it is authorized to submit this Attachment Y notice on behalf of all Campbell Unit 3 owners.

In the event you have any questions regarding this matter, please contact Kathy Wetzel at (517) 788-2039.

Regards,

Timothy J. Sparks
Vice President Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Cc: Kathy Wetzel
Thomas Clark

Electric Supply
Contract/Commitment Cover Sheet

(Note: Contracts, purchase orders, or other commitment instruments will not be signed unless this sheet is completed in full)

Subject/Commitment: MISO Attachment Y Notification of Generating Resources /SCU/ Pseudo-tied Out Generator Change of Status / Including Notification of Rescission Form

Reason: Notice to Suspend Karn Units 3 & 4 effective June 1, 2023.

Check One			
Yes	No*	N/A	
☐	☐	☒	1) Gateway Assessment Tool completed and attached
☒	☐	☐	2) Legal Review / Approval to Form
☐	☐	☒	3) Credit Risk Management Approval
☐	☐	☒	4) Competitive Bid
☐	☐	☒	5) Sole Source Approval completed and attached

*If No is checked or special circumstances apply, please explain:

Legal review by Emerson Hilton.

*Contract Owner: Kathy Wetzel

Department Sign Off
(Signature & Date Required)

ML Metz
Merchant Ops & PSCR

KG Troyer
EGI Contracts & Settlements
Renewables

BD Gallaway
Fuel Supply

TP Clark
Electric Supply

12/14/2021

TJ Sparks
Electric Grid Integration

Form Revised: 04/16/21

*Contract Owner Responsible for Scanning & Placing on SharePoint Site

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic copy of the completed form will be accepted by the Transmission Provider, however, a form will not be considered complete until the original form containing an original signature, including all attachments, is received by the Transmission Provider at the following address: MISO, Attention: Director of Transmission Planning; 720 City Center Drive, Carmel, IN 46032.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re: Campbell Unit 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] CAMPBELL UNITS 1+2: UMBRELLA GIA BETWEEN CONSUMERS, METC + MISO FERC DOCKET ER21-999. CAMPBELL UNIT 3: FERC DOCKET ER06-1441 FOR MISO SERVICE AGREEMENT NO. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 1st [day] of June [month] of 2025 [year]

[ ] Rescind the current notice to SuspendThe facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: TIMOTHY J SPARKS

Title: VP ELECTRIC GRID INTEGRATION

Date:

Contact Information

Email: TIMOTHY.SPARKS@CMSENERGY.COM

Phone: 517 788 1053

Andrew Witmeier
Director, Resource Utilization
317-249-5585
awitmeier@misoenergy.org

VIA OVERNIGHT DELIVERY

March 11, 2022

Timothy J. Sparks
Vice President, Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Subject: **Approval of Campbell Units 1,2 &3 Attachment Y Suspension Notice**

Dear Mr. Sparks,

On December 14, 2021, Consumers Energy Company submitted an Attachment Y Notice to MISO for the suspension of Campbell Units 1,2 & 3, effective June 1, 2025. After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the suspension of Campbell Units 1,2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,2 & 3 may suspend without the need for the generators to be designated as a System Support Resource ("SSR") units as defined in the Tariff.

As there were no reliability criteria violations, MISO will continue to preserve the confidentiality of the Attachment Y Notice.

Please do not hesitate to contact me if you have any questions regarding this matter.

Respectfully,

Andrew Witmeier
Director, Resource Utilization

VIA EMAIL

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

May 28, 2025

Re: Modified Suspension Date for Campbell Units 1, 2, & 3

Mr. Witmeier:

On December 14, 2021, Consumers Energy Company ("Consumers Energy") submitted an Attachment Y Notice to the Midcontinent Independent System Operating, Inc. ("MISO") for the suspension of Units 1, 2, and 3 at the J.H. Campbell Generation Complex ("Campbell Plant"), effective June 1, 2025. After reviewing for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), MISO determined the suspension of Campbell Plant Units 1, 2, and 3, would not result in violations of applicable reliability criteria, as outlined in the Tariff. On March 11, 2022, MISO approved the suspension of Campbell Plant Units 1, 2, and 3 without the need for the generators to be designated as System Support Resource units as defined in the Tariff.

On May 23, 2025, the U.S. Department of Energy ("DOE") issued Order No. 202-25-3 (the "Order"), requiring the Campbell Plant to be available to MISO through August 20, 2025.

In order to comply with the Order, Consumers Energy hereby provides notice to MISO, consistent with Section 38.2.7(d)(ii)(1) of the Tariff, of its intent to modify the current Attachment Y Notice such that the Campbell Plant will now suspend on August 21, 2025.

As noted in Consumers Energy's original Attachment Y Notice, Campbell Unit 3 is jointly owned by Consumers Energy (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that it has notified all Campbell Unit 3 owners of this submittal.

In the event you have any questions regarding this matter, please contact Derek Anspaugh at (517) 788-1869.

Regards,

Sri Maddipati
VP Electric Supply
1945 W. Parnell Rd
Jackson, MI 49901

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic form must be submitted to the Transmission Provider via its online application tool in the manner specified by the Transmission Planning Business Practices Manual (BPM-020), and a form will be considered complete on the date of such online application.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re Campbell 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement]
Campbell Units 1 & 2: Umbrella GIA Between Consumers, METC, and MISO, FERC Docket No. ER24-1359
Campbell Unit 3: FERC Docket No. ER06-1441 for MISO Service Agreement No. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 21 [day] of August [month] of 2025 [year]

[ ] Rescind the current notice to Suspend

The facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: Srikanth Maddipati

Title: VP Electric Supply

Date: May 28, 2025

Contact Information

Email: sri.maddipati@cmsenergy.com

Phone: 517-788-0635

From:	Marc Keyser
To:	Rachael H. Moore; Huaitao Zhang; DEREK S. ANSPAUGH; Adam C. French; NICHOLAS B. TENNEY; Emerson J. Hilton
Cc:	Sumit Pal Brar
Subject:	RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required
Date:	Friday, May 30, 2025 4:05:01 PM

##CAUTION##: This email originated from outside of CMS/CE. Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Rachael: I'm responding back on behalf of the team, after they briefly reviewed with legal here:

we received the Attachment Y, and the new cessation is 8/21/2025. Additionally, you have until 8/21/2027 to submit a new replacement request before the suspension period ends. In other words, the Attachment Y remains as is, still approved, except with a new/different start date.

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Friday, May 30, 2025 12:15 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

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Thank you, Huaitao. Can you confirm that this modification of the suspension start date provided consistent with Section 38.2.7(d)(ii)(1) of the Tariff does not impact the overall approval of the Attachment Y the Company previously received on March 11, 2022, and that the Company is still approved to enter suspension (now effective 8/21/25)?

Thank you!

Rachael Moore | Senior Attorney
[redacted]

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Wednesday, May 28, 2025 1:47 PM

To: Rachael H. Moore <Rachael.Moore@cmsenergy.com>; DEREK S. ANSPAUGH <DEREK.ANSPAUGH@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

##CAUTION##: This email originated from outside of CMS/CE.
Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Rachael,

Thanks for the quick response, and we are all good.

Thanks,
Huaitao

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Wednesday, May 28, 2025 12:40 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

> **Warning!** This email originated from outside the organization and caution should be used when clicking on links/attachments. If you suspect this email is malicious, use the 'Phish Alert' button.

Huaitao –

Attached is the modified Attachment Y with the amended suspension start date of 8/21/2025. Please let me know if we should send this notice of Modified Attachment Y to anyone else at MISO or if you would like us to mail a physical copy as well.

Thank you,
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Rachael H. Moore
Sent: Tuesday, May 27, 2025 11:52 AM
To: Adam C. French <adam.french@cmsenergy.com>; Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <nicholas.tenney@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Good afternoon,

Yes, I will be working with members of the Company to ensure we have the Attachment Y notice updated by 5/28. Please let me know if there is a specific contact at MISO we should plan to send this to.

Thank you!
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Adam C. French <ADAM.FRENCH@cmsenergy.com>
Sent: Tuesday, May 27, 2025 11:49 AM
To: Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

It is my understanding that is being handled by Rachael Moore
RACHAEL.MOORE@CMSENERGY.COM

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Tuesday, May 27, 2025 11:41 AM
To: NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: FW: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

You don't often get email from hzhang@misoenergy.org. Learn why this is important [aka.ms]

##CAUTION##: This email originated from outside of CMS/CE. Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Nick and Adam,

Marc pointed to me that you are the contact for this request.

Thanks,
Huaitao

From: Huaitao Zhang
Sent: Tuesday, May 27, 2025 11:05 AM
To: KATHY S. WETZEL <KATHY.WETZEL@cmsenergy.com>
Cc: timothy.sparks@cmsenergy.com; Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>; Jagdesh Shivani <JShivani@misoenergy.org>
Subject: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Hi Kathy,

Pertain to the Order from Secretary of Energy regarding the suspension/cessation date of Campbell units 1,2&3, MISO requests Consumer Energy to submit the following application updates to MISO by 5/28/2025:

Attachment Y request with suspension start date as 8/21/2025

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

Thanks,
Huaitao Zhang
Resource Utilization Engineer

Integrity | Collaboration | Commitment | Creativity | Adaptability

Attachment D

Consumers' Responses from June 10, 2025

Question:

23. Absent continued operation of the Campbell Plant, what was Consumers Energy's Zone Resource Credit (ZRC) position for planning year 2025-2026.

Response:

The table below shows our capacity positions using the initial Planning Reserve Margin Requirement (PRMR) for each season of planning year 2025. These numbers do not include any contributions from the Campbell coal-fired generating units.

PY2025	**ZRC**
Summer	272.9
Fall	842.7
Winter	0.0
Spring	4.3

Date: June 10, 2025

Question:

24. How many ZRCs does Consumers anticipate will be accredited for the continued operation of the Campbell Plant?

Response:

At this time we do not anticipate the Campbell units contributing any Zonal Resource Credits to our capacity positions throughout planning year 2025.

Date: June 10, 2025

Attachment P

Michigan AG Request for Rehearing of Order No. 202-25-3

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Order No. 202-25-3

REQUEST FOR REHEARING BY MICHIGAN ATTORNEY GENERAL DANA NESSEL

Dana Nessel
Michigan Attorney General

Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

Dated: June 18, 2025

Pursuant to section 313*l* of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Michigan Attorney General Dana Nessel, on behalf of the people of the State of Michigan, requests that the Department of Energy (Department or DOE) grant rehearing of Order No. 202-25-3 (May 23, 2025) ("Order"). The Order invoked the Department's emergency authority under section 202(c) of the Act to prevent the scheduled retirement of the J.H. Campbell power plant (J.H. Campbell) in West Olive, Michigan.

The Order is an unlawful abuse of the Department's emergency authority. Until now, the Department has reserved section 202(c) for real emergencies like natural disasters and extreme weather and has typically acted at the behest of grid operators or governmental bodies. In the Order, acting on its own motion and without notice, the Department declares that the retirement of J.H. Campbell presents an emergency. But the Order's emergency determination cannot bear even the mildest scrutiny.

The scheduled retirement of J.H. Campbell was the culmination of a carefully planned process that unfolded over four years. Under the oversight of the Michigan Public Service Commission (MPSC), Consumers Energy (Consumers) executed a plan to retire an old and inefficient facility, J.H. Campbell, and replace it largely with newer resources that would both increase Consumers' available generation capacity and save its ratepayers money. J.H. Campbell's proposed retirement was also studied carefully by the Midcontinent Independent System Operator (MISO), the regional

grid operator, which determined that the facility could retire without causing reliability issues.

In the Order, the Department uses its authority under section 202(c) in a manner untethered from the need to identify a real emergency and unhindered by the statutory requirement that the actions it orders go no further than necessary to address the emergency. The result of this overreach will be unnecessary costs imposed on already-overburdened ratepayers, needless pollution emitted into Michigan and its neighboring states, and an unprecedented intrusion into the authority of states and the Federal Energy Regulatory Commission to regulate the resource adequacy of our electric grid.

I. MOTION TO INTERVENE

The Michigan Attorney General,[1] on behalf of the people of the State of Michigan, moves to intervene in this proceeding and thereby to become a party for purposes of Section 313*l* of the Act, 16 U.S.C. § 825*l*. The People of the State of Michigan have an interest in and are aggrieved by the Order in several ways. First, households and businesses in Michigan will pay higher electricity bills as a result of the Order. The retirement of J.H. Campbell and its replacement with more cost-effective resources were elements of a careful plan expected to save Michigan

[1] *See* MCL 14.28 ("The attorney general . . . may, when in [her] own judgment the interests of the state require it, intervene in and appear for the people of this state in any other court or tribunal, in any cause or matter, civil or criminal, in which the people of this state may be a party or interested."). *See also In re Certified Question*, 465 Mich 537, 543-545; 638 NW2d 409 (2002), *Gremore v Peoples Community Hospital Authority*, 8 Mich App 56; 153 NW2d 377 (1967), and *People v O'Hara*, 278 Mich 281; 270 NW2d 298 (1936).

ratepayers nearly $600 million.[2] By ordering the continued operation of J.H. Campbell, the Order ensures that Michigan ratepayers will pay higher costs. Although the precise amounts of costs are not yet known, it is certain that Michigan ratepayers will be stuck with substantial new costs in excess of what they would have paid absent the Order.

Second, the People of the State of Michigan will suffer environmental harms as a result of the Order. J.H. Campbell is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[3] among other pollutants. By prolonging the operations of J.H. Campbell beyond its planned retirement date, the Order will increase the amount of pollution emitted in the state of Michigan, causing harms to the public health and welfare.

Third, the retirement of J.H. Campbell on May 31, 2025, was a provision agreed to as part of a settlement agreement in Michigan Public Service Commission Case (MPSC) No. U-21090, to which the Michigan Attorney General was a party. Because the Order deprives the Michigan Attorney General of the benefit of her bargain under the settlement agreement, the Michigan Attorney General will suffer a discrete and separate harm as a result of the Order.

II. BACKGROUND

A. DOE's Historical Use of Section 202(c).

[2] *See* Michigan Public Service Commission Case No. U-21090-0867, Reply Brief of Consumers at 1 – 2, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000032ZSXAA2.
[3] *See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).

In the past, the Department has used section 202(c) sparingly. The Department has used this authority only in response to concrete, particularized emergencies, and subject to limitations to ensure that the Department's reach extends no further than necessary to address the emergency at hand.

Between enactment of the Department of Energy Organization Act in 1977, Pub. L. No. 95-91, and the end of last year, the Department appears to have used section 202(c) nineteen times, not counting amendments and extension orders. DOE's first usage of section 202(c) came in response to the California Energy Crisis in 2000.[4] That order was followed by two others directing the operation of the Cross-Sound Cable, a submarine transmission line connecting New York and Connecticut that was complete but that had been delayed from entering service due to environmental permitting issues.[5] But by far the most common usage – comprising 13 of 19 instances – has been in response to extreme weather events such as hurricanes,[6] extreme cold,[7] and extreme heat.[8] In each of these weather-driven cases, the exercise of emergency power was requested by the relevant system operator or responsible utility, or both.

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[4] DOE, *Order Pursuant to Section 202(c) of the Federal Power Act* (Dec. 14, 2000). Section 202(c) was used by the Federal Power Commission prior to the Department of Energy Organization Act's creation of DOE. Those uses were generally limited to orders directing interconnection as a result of discrete and sudden emergencies or war. *See* Benjamin Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. 789, 822 (2025).

[5] *See* DOE Order No. 202-02-1 (Aug. 16, 2002); DOE Order No. 202-03-01 (Aug. 14, 2003).

[6] *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (response to Hurricane Rita); DOE Order No. 202-08-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton).

[7] *See* DOE Order No. 202-21-1 (Feb. 14, 2021); DOE Order No. 202-22-3 (Dec. 23, 2022); DOE Order No. 202-22-4 (Dec. 24, 2022).

[8] *See* DOE Order No. 202-20-2 (Sept. 6, 2020) (responding to extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 202-22-1 & 2 and amendments (same).

And in each, DOE carefully limited its remedy to ensure that generation facilities were only ordered to run in circumstances necessary to address the emergency and in a manner so as to minimize any conflict with environmental requirements.[9] DOE also limited the duration of those orders to the minimum period necessary to address the emergency, often shorter than 10 days.[10]

Prior to the Order, DOE had used section 202(c) on three occasions to delay the retirement of generation facilities.[11] These cases had key features in common. In each: (i) the order was requested by a system operator or governmental body; (ii) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (iii) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and, (iv) DOE tailored its order to go no further than necessary to address the emergency.

The first such instance came in 2004, when the District of Columbia's Public Service Commission requested an order directing the continued operation of a power plant located in Alexandria, Virginia, owned by the Mirant Corporation (Mirant). After its state regulator found the plant to be out of compliance with its air permit, Mirant abruptly announced that the plant would close.[12] The D.C. Public Service Commission, supported by the local utility, PEPCO, explained that the Mirant facility

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[9] *See supra* notes 3 – 5.
[10] *Id*.
[11] Nor did the DOE's predecessor agency, the Federal Power Commission, use section 202(c) to delay retirement of any generation units between the section's enactment in 1935 and the formation of DOE in 1977. *See* Rolsma, 57 U. Conn. L. Rev. at 843-46.
[12] DOE Order No. 202-05-3 (Dec. 20, 2005) at 1 (explaining that Mirant provided emissions information to its state regulator on August 19, 2005, the regulator demanded immediate action that same day, and Mirant decided to cease operations on August 24).

directly powered downtown D.C. and that, without it, critical federal infrastructure faced an unacceptable risk of blackout.[13] Before acting on the request, the Department commissioned an analysis from the Oak Ridge National Laboratory that confirmed the threat that the plant's closure would pose to reliability in D.C.[14] Based on that study, and based on the severity of the harm that could result from a prolonged power outage to downtown D.C., the Department issued an order directing the continued operation of the Mirant facility.[15] The Department took pains, however, to limit its order to go no further than necessary to address the emergency. The Department directed Mirant to maintain the facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[16]

Twelve years later, in 2017, the Department received a request from the Grand River Dam Authority (GRDA), an Oklahoma state agency, to direct the continued operation of Unit No. 1 at the Grand River Energy Center. GRDA explained that the Grand River Energy Center was needed to provide dynamic reactive power support to the local grid, a fact confirmed by the region's Reliability Coordinator, the Southwest Power Pool (SPP). GRDA explained, however, that it would be unable to provide reactive power without action from DOE. Unit No.1, the subject of the request, had been ordered to close by an Administrative Order of the Environmental Protection Agency. Unit No. 2 had been struck by lightning and was under repair.

[13] *Id*. at 2.
[14] *Id*. at 3 – 4.
[15] *Id*. at 5 – 8.
[16] *Id*. at 10 – 11.

And, construction of the new Unit No. 3 had been delayed because flooding in Louisiana interfered with the fabrication of essential project materials.[17] The Department granted GRDA's request, ordering Unit No. 1 to remain in operation for 90 days or until Unit No. 2 or Unit No. 3 were brought online, whichever came first.[18] The Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[19]

Later that year, the Department received a pair of requests from PJM and Dominion Virginia (Dominion) to direct the continued operation of Units 1 and 2 of the Yorktown Power Station. PJM and Dominion explained that, based on PJM load flow studies, these units were necessary to prevent uncontrolled power disruptions and shedding of critical loads in the North Hampton Roads area east of Richmond.[20] DOE issued an order directing Dominion to maintain operation at the two units, but to dispatch those units "only when called upon by PJM for reliability purposes."[21] DOE later extended the order several times due to the delayed completion of the transmission line needed to resolve the reliability issue. In doing so, DOE cited the "imminent" risk of load-shedding in the North Hampton Roads area absent extension of the order.[22] In its extension order, the Department continued to limit dispatch of

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[17] Letter Request of Grand River Dam Authority, April 11, 2017. Available at https://www.energy.gov/sites/default/files/2017/05/f34/GRDA%20public%20202%28c%29%20letter.pdf.
[18] DOE Order No. 202-17-1 at 2.
[19] *Id*.
[20] DOE Order No. 202-17-2, at 1.
[21] *Id*. at 2.
[22] DOE Order No. 202-17-4, Summary of Findings, Sept. 14, 2017.

the units only when called upon by PJM for reliability purposes and, further, directed PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating the units.[23]

B. Executive Order 14262 and the White House Strategy to Prop Up the Coal Industry.

Over the past several months, the White House and the Department have sought to radically transform how section 202(c) of the Federal Power Act is applied, departing in almost every material respect from the longstanding approach described above. As shown below, the Order cannot be understood intelligibly as a response to a discrete event or emergency akin to past orders under section 202(c). Rather, it can only be understood as part of a long-term and multi-part strategy to preserve coal and other fossil fuel generation under the guise of grid reliability concerns.

On April 8, 2025, President Trump issued Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*.[24] The Executive Order was issued concurrently with three other executive actions aimed at supporting the coal industry that were announced at a White House political event explicitly focused on that objective.[25] This event, and the related Executive Order, are one of several in a series of public actions by the Administration aimed at reversing coal plant retirements and promoting fossil fuel generation.

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[23] DOE Order No. 202-17-4 at 2.
[24] Executive Order 14262, 90 Fed. Reg. 15521 (April 14, 2025).
[25] New York Times, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry* (April 8, 2025); Executive Order 14261, *Reinvigorating Americans Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15517 (April 14, 2025); Executive Order 14260, *Protecting American Energy from State Overreach*, 90 Fed. Reg. 15513 (April 14, 2025); *Regulatory Relief for Certain Stationary Sources To Promote American Energy*, 90 Fed. Reg. 16777 (April 21, 2025).

Executive Order 14262 directs DOE to, among other things, streamline and expedite the issuance of emergency orders under section 202(c), specifically in order to "safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply [that] is necessary to prevent a complete grid failure."[26] It also directs DOE to take a subsequent series of actions related to national resource adequacy, including mandating:

- the development of a uniform methodology for assessing reserve margins and identifying "at-risk" regions;
- establishment of a process by which the developed methodology and any analysis results are regularly assessed; and,
- establishment of a protocol to identify generation resources within a region that are critical to system reliability, a mechanism under section 202(c) to ensure such generation resources are appropriately retained and, for resources over 50MW, are prevented from leaving the bulk-power system or converting their source of fuel.[27]

DOE has not yet published the analysis or protocols—the deadline provided in Executive Order 14262 is July 7.

Executive Order 14262 states that it is intended to help address the national energy emergency declared in the earlier-issued Executive Order 14,156, *Declaring a National Energy Emergency*.[28] In fact, this order is part of a broader pattern in which the Administration has expansively invoked emergency powers to achieve long-standing political objectives, rather than respond to genuine, unforeseen crises. The

[26] Executive Order 14262 section 3(a).
[27] Executive Order 14262 section 3(b), (c).
[28] Executive Order 14262, section 2.

President has declared eight national emergencies in 2025 alone—more than any other President in the first 100 days of an administration.[29]

C. The Planned Retirement of JH Campbell.

i. Description of J.H. Campbell

J.H. Campbell is a three-unit coal-fired power plant with a total rated net generating capability of approximately 1,450 megawatts (MW).[30] (The Order incorrectly states that J.H. Campbell has a capacity of 1,560 MW). In its current degraded condition, however, J.H. Campbell has a maximum capacity of 920 MW.[31] Part of that difference comes from the fact that Unit 2 is not operational, nor was it operational when the Order was issued. When Unit 2 comes back on-line later this month, the maximum capacity of the facility will be 1,180 MW. J.H. Campbell Unit 1 is 63-years-old and has a rated net generating capability of 261 MW, but now has an effective maximum output of 220 MW.[32] Unit 2 is 58-years-old and has a rated net generating capability of 356 MW. Currently out of service, when Unit 2 comes back online it will have a maximum capacity of 260 MW.[33] Unit 3 is 45 years old and has a rated net generating capability of 843 MW. The current maximum capacity of Unit 3 is 700 MW.[34] Consumers operates the entire J.H. Campbell plant and is the sole

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[29] *See* https://www.brennancenter.org/our-work/research-reports/declared-national-emergencies-under-national-emergencies-act.

[30] Michigan Public Service Commission (MPSC) Case No. U-21585, Direct Testimony of Richard Blumenstock, p. 7, Table 1 (5 Tr 1394-95); see also, https://www.consumersenergy.com/about-us/electric-generation/campbell-complex-retirement, last checked June 11, 2025 (reporting 1,450 MW of capacity).

[31] Conversation between representatives of Consumers and the undersigned counsel, June 12, 2025.

[32] *Id.*

[33] *Id.*

[34] *Id.*

owner of Units 1 and 2. Consumers owns about 93% of Unit 3, the Michigan Public Power Agency owns 4.8% of Unit 3, and Wolverine Power Supply Cooperative owns less than 2% of Unit 3.[35]

J.H. Campbell and Consumers' service territory are located within MISO Local Resource Zone 7. Most of the lower peninsula of Michigan is in MISO Zone 7, except for a small area in the southwest portion of the State, which is in PJM.

ii. State proceeding approving the retirement of J.H. Campbell

In 2021, Consumers proposed to retire J.H. Campbell in 2025 for economic reasons. The MPSC thoroughly reviewed the proposed retirement for a year in an integrated resource plan (IRP) proceeding governed by Michigan statute.[36] No party in the case opposed the retirement of Units 1 and 2; and only a few opposed the retirement of Unit 3.[37] The MPSC ultimately approved Consumers' proposed retirement of J.H. Campbell in a settlement joined by most of the parties to the case. A single party appealed the MPSC's decision to approve the retirement of Unit 3, but the Michigan Court of Appeals affirmed that decision in 2023.[38] Both the MPSC and the appeals court found that Michigan would still have more than enough generating capacity to serve demand after J.H. Campbell retired.[39]

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[35] MPSC Case No. U-21090 (Kapala Direct, 7 Tr 1739); Ex. WPSC-1, p. 19 (Agreement, p. 11), section 2.1, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001QqldAAC.

[36] MCL 460.6t.

[37] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 8.

[38] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[39] *Id.*

Michigan's IRP statute requires electric utilities whose rates are regulated by the MPSC to periodically file an integrated resource plan. The IRP is a projection of the utility's load obligations and a plan to meet those obligations.[40] The IRP statute directs the MPSC to approve a plan if the MPSC determines that it "represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."[41] To make that decision, the statute instructs the MPSC to consider whether the IRP appropriately balances seven statutory factors: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective.[42]

The IRP statute also directs the MPSC to establish – among other things – computer modeling scenarios that must be used to analyze the costs of possible plans in an IRP, including costs associated with plant retirement dates.[43] In the modeling used to prepare its 2021 IRP, Consumers determined that it would be most cost-effective to retire the entire J.H. Campbell plant in 2025.[44] Later in the proceeding, Consumers conducted more modeling that compared other possible retirement dates

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[40] MCL 460.6t(3).

[41] MCL 460.6t(8)(a).

[42] *Id.*

[43] MCL 460.6t(1).

[44] MPSC Case No. U-21090 (Blumenstock Direct, 3 Tr 99 and 147-49), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001OEXnAAO.

to a 2025 retirement and again concluded that the most cost-effective retirement date was 2025.[45] Among other things, parties to the IRP case noted that the 2025 retirement of J.H. Campbell would save ratepayers $150 million in avoidable capital expenditures.[46]

After months of litigation, most of the parties reached a settlement agreement, which Consumers filed with the MPSC on April 20, 2022.[47] The settlement agreement approved the retirement of J.H. Campbell – but it also approved the construction, procurement, and extension of other major generating resources. The net effect of these changes was to substantially increase the total generating resources available to MISO Zone 7.

iii. Effect of Consumers' overall plan on resource adequacy

MISO measures capacity for resource adequacy purposes in zonal resource credits (ZRCs). One ZRC is equal to one MW of deliverable seasonal accredited capacity, which is the net amount of capacity MISO calculates it can reasonably expect from a resource.[48]

Consumers' IRP projected that the entire J.H. Campbell plant would provide 1,346 ZRCs in 2024, its last full year of planned operation.[49] In recognition of the

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[45] *Id*. (Walz Rebuttal, 3 Tr 364-73 & Ex A-123; Blumenstock Rebuttal, 3 Tr 178-79).

[46] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, pp. 48, 55.

[47] MPSC Case No. U-21090-0777 (Settlement Agreement), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002gLkGAAU.

[48] MISO Knowledge Base, KA-01402, available at https://help.misoenergy.org/knowledgebase/article/KA-01402/en-us#:~:text=Zonal%20Resource%20Credits%20(ZRC)%20are,Seasonal%20Accredited%20Capacity%20(SAC); MISO, Resource Adequacy, available at https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc.

[49] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 33.

reduced capacity that would result from the retirement of J.H. Campbell, the settlement authorized Consumers to acquire the Covert gas plant, which Consumers has done.[50] At the time, the Covert plant was in the PJM regional transmission organization – but after acquiring it, Consumers redesignated the Covert plant as part of MISO Zone 7.[51] This action added 1,114 ZRCs to Zone 7 – almost enough by itself to offset the ZRCs removed by the Campbell retirement.[52]

The settlement also authorized Consumers to continue operating Units 3 and 4 of the Karn plant – peaking units that burn natural gas and oil – until 2031, rather than retire them in 2023 as originally planned.[53] This action maintained another 784 ZRCs in Zone 7 beyond what was in Consumers' original plan.[54] The settlement agreement also authorized Consumers to develop or acquire 250 ZRCs of new solar generation by mid-2025, increasing to 852 ZRCs by mid-2028; added 94 ZRCs of demand response and energy waste reduction by mid-2025; and added 71 ZRCs of new battery storage in 2024-2027.[55] The settlement also provided that Consumers would issue a solicitation for power purchase agreements (PPAs) that would provide capacity beginning in 2025/2026, right after J.H. Campbell's retirement.[56] The PPA solicitation would seek up to 500 MW of dispatchable generation, and up to 200 MW of clean energy resources.[57]

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[50] *Id*. at 5.
[51] *Id*. at 91.
[52] *Id*. at 50.
[53] *Id*. at 11.
[54] *Id*.
[55] *Id*. at 23.
[56] *Id*. at 6 – 7. In MISO, the planning year runs from June 1 through May 31.
[57] *Id*.

Overall, the plan approved in the settlement was projected to increase Zone 7's capacity by at least 127 ZRCs by June 2025 – an increase that will grow to at least 923 ZRCs by 2028, not including the 700 MW of additional capacity sought in the PPA solicitations.[58]

iv. MPSC approval of the settlement and affirmance on appeal

Consumers' IRP settlement agreement was supported by most parties in the case, including Consumers, Staff, the Attorney General, consumer advocates, a transmission company, commercial and industrial customers, businesses in the advanced energy sector, environmental groups, and third-party energy developers.[59] The MPSC approved the Settlement Agreement on June 23, 2022.[60] The state commission found that the plan embodied in the settlement "is the most reasonable and prudent means of meeting Consumers' energy and capacity needs."[61]

In reaching these conclusions, the MPSC specifically addressed resource adequacy.[62] After discussing the record evidence regarding the Covert plant, Karn units 3 and 4, new battery storage, and ongoing investments in solar, energy waste reduction, and demand response,[63] the MPSC concluded that "the approval of the settlement agreement will enhance resource adequacy in Zone 7 in both the near-term and long-term."[64] One party, Wolverine Power Supply Cooperative, appealed

[58] *Id.* at 24.
[59] *Id.* at 30 – 31.
[60] *Id.* at 87-93.
[61] *Id.* at 95.
[62] *Id.* at 90-93.
[63] *Id.*
[64] *Id.* at 92.

the MPSC's decision to approve the Campbell plant retirement. The Michigan Court of Appeals affirmed the MPSC. The court specifically addressed resource adequacy, quoted the MPSC's findings about the generating resource additions, and found that the state commission's decision was based on substantial evidence.[65]

v. Subsequent proceedings before the MPSC show that both Consumers' service territory and Michigan as a whole will have sufficient capacity this summer and for years to come

Filings in MPSC proceedings regarding capacity supply and resource adequacy demonstrate that there is no capacity shortfall. To the contrary, the most current available information is that both Consumers and MISO Zone 7 will have sufficient capacity this summer and for years to come. On June 10, 2025, Consumers reported that it now has a surplus of 273 ZRCs for this summer.[66] Consumers further reported that it expects J.H. Campbell will not contribute any ZRCs to the Company's summer position.[67]

Consumers' ZRC projections compare Consumers' available resources not just to projected actual demand but to the planning reserve margin requirement (PRMR). MISO establishes the PRMR as the amount of reserve margin target necessary to meet NERC's Loss of Load Expectation (LOLE) standard of 1 day in 10 years.[68] NERC

[65] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[66] *See* Attachment D, Consumers' Responses from June 10, 2025.

[67] *Id*.

[68] MISO Resource Adequacy Business Practices Manual, BPM-011-r31, p. 27, Section 3.4.2 LOLE Analysis; MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 9.

defines the LOLE as "the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand."[69]

For Michigan as a whole, the MPSC Staff finds in its annual capacity demonstration report that – except for one small municipal utility – all Michigan load serving entities "were able to procure the necessary capacity to demonstrate compliance for the current planning year in all four seasons" in Planning Year 2025-26.[70] The Staff Report also finds that there are more than enough resources in Zone 7 to meet the MISO Local Clearing Requirement (LCR) – which is the minimum amount of resources that must be located within a MISO local resource zone to meet the reliability standard.[71] While Zone 7 did not have enough internal resources to meet its entire PRMR, it is not required to do so under MISO rules, and the zone is able to import 785.5 ZRCs of external resources to meet its PRMR for the current planning year.[72]

Looking ahead, the Staff Report projects that Zone 7 will have more than enough resources to meet both its LCR and the PRMR in each of planning years 2026, 2027, and 2028.[73] Zone 7's LCR surplus will increase each year to reach 4,975 ZRCs by Planning Year 2028, and its PRMR surplus will increase each year to reach 3,428 ZRCs by Planning Year 2028.[74]

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[69] NERC Probabilistic Assessment Technical Guideline, August 2016, p. 2.
[70] MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 6.
[71] *Id*. at 16.
[72] *Id*.
[73] *Id*. at p. 26, Appendix C.
[74] *Id*.

vi. MISO approved the retirement of J.H. Campbell after a detailed study process governed by MISO's FERC-approved tariff

More than three years before the Secretary issued Order 202-25-3, MISO determined via a detailed technical study that retirement of J.H. Campbell would not materially impact reliability in MISO. That determination remains in effect.

Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires that the owner of a Generation Resource that is planning to suspend operations of all or a portion of that resource must notify MISO at least 26 weeks in advance by submitting a completed Attachment Y Notice.[75] The Tariff states that MISO will perform an Attachment Y Reliability Study to determine whether the Generation Resource is necessary for the reliability of the Transmission System based on analyses described in the Tariff and criteria in the MISO Business Practices Manuals.[76]

On December 14, 2021, Consumers submitted to MISO an Attachment Y notice of intent to suspend J.H. Campbell Units 1, 2, and 3 effective June 1, 2025.[77] After more than a year of study, MISO approved the suspension on March 11, 2022.[78] MISO stated that after reviewing the J.H. Campbell suspension for power system reliability impacts, MISO had determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,

[75] MISO Tariff, Section 38.2.7(a)(i).
[76] MISO Tariff, Section 38.2.7(c).
[77] Attachment C (Letter dated December 14, 2021, from Timothy J. Sparks, Consumers Energy, to Andrew Witmeier, MISO, and Attachment Y Notification of Generating Resources Change of Status).
[78] Attachment C (Letter dated March 11, 2022, from Andrew Witmeier, MISO, to Timothy J. Sparks, Consumers Energy, re: Approval of Campbell Units 1, 2 & 3 Attachment Y Suspension Notice).

2 & 3 may suspend without the need for the generators to be designated as a System Support Resource ('SSR') units as defined in the Tariff."[79]

On May 27, 2025, MISO requested that Consumers submit a modified Attachment Y request with a new suspension start date of August 21, 2025, consistent with the date in Order 202-25-3.[80] Consumers submitted the modified Attachment Y notice with the new date on May 28, 2025.[81] On May 30, 2025, MISO notified Consumers that with the modification, "the Attachment Y remains as is, still approved, except with a new/different start date."[82]

D. The Order

On May 23, 2025, the Secretary of Energy issued the Order pursuant to section 202(c) of the Federal Power Act, determining that an emergency exists in the region of the country served by MISO "due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" and ordering Consumers and MISO to ensure the continued operation of J.H. Campbell for at least 90 days notwithstanding the longstanding plan to retire the facility on May 31, 2025. In issuing the Order, the Department issued a press release that, like Executive

[79] *Id*.
[80] Attachment C (Email dated May 27, 2025, from Huaitao Zhang, MISO, to Kathy Wetzel, Consumers Energy).
[81] Attachment C (Email dated May 28, 2025, from Rachael Moore, Consumers Energy to Huaitao Zhang, MISO).
[82] Attachment C (Email dated May 30, 2025, from Marc Keyser, MISO, to Rachael Moore, Consumers Energy).

Order 14262, states the Order "is in accordance with President Trump's Executive Order: Declaring a National Energy Emergency."[83]

Over four short paragraphs, the Order outlines the "emergency situation" allegedly necessitating invocation of section 202(c) authority. It points primarily to "*potential* tight reserve margins during the summer 2025 period," citing to the North American Electric Reliability Corporation (NERC) 2025 Summer Reliability Assessment, including the statement that MISO is "at elevated risk of operational reserve shortfalls during periods of high demand or low resource output."[84] The Order then describes the retirement of thermal generation capacity including the retirement of approximately 2,700 MW of coal-fired capacity in Michigan since 2020 and the scheduled May 31, 2025, retirement of J.H. Campbell.[85] The Order acknowledges Consumers' acquisition of 1,200 MW of replacement natural gas capacity and MISO's April 2025 conclusion that its auction resulted in "demonstrated sufficient capacity,"[86] but does not reference, let alone consider, the extensive processes that MISO and the MPSC undertook to evaluate and mitigate any reliability or resource adequacy risk that would be caused by the retirement of J.H. Campbell.[87] Nor does the Order describe any actions that MISO or Consumers have taken or could take to mitigate any alleged emergency conditions short of ordering the continued operation of the plant. Rather, it relies almost exclusively on:

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[83] DOE Press Release (May 23, 2025) available at https://www.energy.gov/articles/energy-secretary-issues-emergency-order-secure-grid-reliability-ahead-summer-months.
[84] DOE Order 202-25-3 at 1 (emphasis added).
[85] *Id.* at 1.
[86] *Id.* at 2.
[87] *See* Section II.C *supra*.

- The general statement in NERC's 2025 Summer Reliability Assessment that there is anticipated to be "elevated risk of operating reserve shortfalls"
- Language in MISO's Planning Resource Auction Results for Planning Year 2025-26 that, "for the northern and central zones, which includes Michigan, 'new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources,'" and that the results "reinforce the need to increase capacity" and,
- Language from the MISO Auction Results that the summer months have, relative to other times, the "highest risk and tighter supply-demand balance."[88]

The Order concludes that "additional dispatch of the Campbell Plant," for the 90-day duration of the order and on conditions contained in the order, "is necessary to best meet the emergency and serve the public interest."[89] As a result, the Order mandates that:

- MISO and Consumers Energy take all necessary steps to ensure the Campbell Plant is available for dispatch;[90]
- MISO employ economic dispatch of the plant, and that Consumers comply with all such dispatch orders;[91]
- All operation of J.H. Campbell "must comply with applicable environmental requirements . . . to the maximum extent feasible while operating consistent with the emergency conditions."[92]
- MISO submit reports to DOE on plant operations, environmental impacts, and actions taken to comply with the Order.[93]
- "Relevant governmental authorities" take such action as necessary to enable MISO to effectuate the dispatch and operation of the units.[94]
- Consumers request any necessary revisions or waivers to effectuate the order with FERC.[95]

III. STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

[88] DOE Order 202-25-3 at 2.
[89] DOE Order 202-25-3 at 2.
[90] *Id.* at 2 (Ordering Paragraph A).
[91] *Id.* (Ordering Paragraph A).
[92] *Id.* at 3 (Ordering Paragraph C).
[93] *Id.* at 3 (Ordering Paragraph B, D).
[94] *Id.* at 3 (Ordering Paragraph E).
[95] *Id.* at 3 (Ordering Paragraph F).

As explained in Section IV below, the Michigan Department of Attorney General submits the following statement of issues and specifications of error:

1. The Order is contrary to law because it fails to establish the existence of an emergency under section 202(c) or the Department's regulations implementing section 202(c). The statutory text, legislative history, judicial construction and DOE's regulations all confirm that an "emergency" is an occurrence that is sudden, unexpected and requiring immediate action. The Order introduces no facts that would satisfy that definition. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371; *Richmond Power and Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978); *Otter Tail Power Co. v. Fed. Power Comm*., 429 F.2d 232, 233-34 (1970).

2. The Order is contrary to law because it exceeds the Department's statutory authority. Abusing a statute meant only for emergencies, the Order intrudes on authority reserved to States and to other federal regulators to regulate resource adequacy. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy, or the authority to decide which power plants may retire except for so long as a true emergency exists. The Department may not "discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority." *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

3. The Order fails to present substantial evidence for its emergency determination and fails to exercise reasoned decision-making by ignoring critical facts and shortcomings in its analysis. Specifically, the Order: (i) presents a discussion of the NERC 2025 Summer Reliability Assessment that is unreasoned, incomplete, and that fails to substantiate the existence of an emergency; (ii) the Order's apparent reliance on generator retirements in Michigan as evidence of an emergency is unreasonable; (iii) the Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless, (iv) the Order fails even to acknowledge that MISO approved the retirement of J.H. Campbell through the study process governed by its FERC-approved tariff; (v) the Order makes no effort to review the proceedings before the MPSC, or to note any consultation with Michigan officials as required by 42 U.S.C. § 7113; (vi) the Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate. *E.g. Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017) (order under the Federal Power Act must reflect "a principled and reasoned decision supported by the evidentiary record" (quotation marks omitted)); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (agency must examine the relevant data and articulate a satisfactory

explanation for its action including a rational connection between the facts found and the choice made); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962) (an "agency must make findings that support its decision, and those findings must be supported by substantial evidence").

4. The Order is arbitrary and capricious and contrary to law because section 202(c) provides no authority for the Department to command a generator to engage in "economic dispatch." 16 U.S.C. § 824a(c); *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001) (absent statutory authorization, an agency's "action is plainly contrary to law and cannot stand").

5. The Order is arbitrary and capricious and contrary to law because the Department failed to limit its remedy as required by section 202(c)(2). The Order adheres to neither the temporal constraint nor the environmental constraints imposed by section 202(c)(2). 16 U.S.C. § 824a(c)(2).

6. The Order violates the National Environmental Policy Act because it fails to assess the environmental consequences of a major federal action significantly affecting the human environment. 42 U.S.C. § 4321; *et seq*.

IV. REQUEST FOR REHEARING

A. The Department Has Failed to Establish the Existence of an Emergency under Section 202(c) or the Department's Regulations Implementing Section 202(c).

i. Congress limited DOE's authority under section 202(c) to the unique circumstances of war or emergency

Section 202(c) confers an extraordinary power. Enacted in 1935, section 202(c) empowered the Federal Power Commission to command action from market participants and – crucially – to do so freed from most of the core procedural safeguards, jurisdictional boundaries, and substantive limitations that undergird the rest of the Federal Power Act. While the rest of the Act authorizes Commission action

only after opportunity for hearing,[96] section 202(c) allows the Commission (now the Department) to act on its own motion and without prior notice. And in profound contrast to the rest the Federal Power Act and general utility law principles,[97] section 202(c) empowers the Department to require utilities to incur costs – through a command to provide generation or transmission service – without first considering the impact to ratepayers or whether the resulting rates will be just and reasonable.

It comes as no surprise, therefore, that when Congress granted the Commission this extraordinary power, Congress restricted its use to extraordinary circumstances. Section 202(c) authorizes action only "[d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." The Act permits some measure of flexibility with respect to what type of events may cause the emergency, allowing for "other causes" beyond those enumerated. But the Act is clear that any such event, including a "shortage of electric energy," must be one that constitutes an "emergency."

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[96] *See e.g.*, 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o & 824p.

[97] Two cornerstones of the law of regulated utilities are the filed rate doctrine and the rule against retroactive ratemaking. As FERC has explained, "a central purpose of the filed rate doctrine and the rule against retroactive ratemaking is to protect ratepayers from being subjected to an additional surcharge above the rate on file for service already performed." *Old Dominion Elec. Coop.*, 154 FERC ¶ 61,155 (2016). In its June 6, 2025, complaint filed in FERC Docket No. EL25-90, Consumers asserts that the filed rate doctrine and the rule against retroactive ratemaking are inapplicable in the context of an order under section 202(c).

Because the Act does not define "emergency," the Department must look first to the public meaning of that word at the time of enactment. Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "sudden or unexpected appearance or occurrence . . . . An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency." Contemporary dictionaries likewise define "emergency" to refer to a circumstance that is "unexpectedly arising, and urgently demanding immediate attention."[98]

These definitions accord with the legislative history of the Federal Power Act, which characterized section 202(c) as an authority to be used in response to "crises":

> This is a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose. Drought and other natural emergencies have created similar crises in certain sections of the country; such conditions should find a federal agency ready to do all that can be done in order to prevent a break-down in electric supply.[99]

The few courts that have had occasion to opine on the meaning of "emergency" in section 202(c) have likewise emphasized that the provision applies in very limited circumstances, and not as a tool to address longer-term, structural concerns. In *Richmond Power and Light v. FERC*, the D.C. Circuit upheld the Commission's judgment that the dependence on foreign oil occasioned by the 1973 oil embargo was

[98] *See Acuity Ins. Co. v. McDonald's Towing & Rescue, Inc.,* 747 F. App'x 377, 380–81 (6th Cir. 2018) (addressing a statute that leaves "emergency" undefined and quoting 7 Oxford English Dictionary 231 (2012) among others to supply a definition).
[99] S. Rep. No. 74-621 at 49 (1935).

not an "emergency" under the Act, noting that section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[100]

In *Otter Tail Power Co. v. Fed. Power Comm'n,* the U.S. Court of Appeals for the Eighth Circuit described section 202(c) as enabling the Commission to "react to a war or natural disaster." The court also distinguished section 202(c) from section 202(b), under which the Commission may also order interconnections, but only after a hearing. The court explained that, in contrast to section 202(c), which "enables the Commission to proceed without notice or hearing" to address immediate crises, section 202(b) "applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[101]

Through its regulations, the Department has also interpreted "emergency" for purposes of section 202(c) to mean circumstances that arise suddenly and unexpectedly:

> "Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities.[102]

In summary, the plain meaning of the statutory text, its legislative history, judicial construction, and the Department's own regulations all establish that an

[100] 574 F.2d 610, 615 (D.C. Cir. 1978).
[101] 429 F.2d 232, 234 (8th Cir. 1970).
[102] 10 C.F.R. § 205.371.

"emergency," including one occasioned by a "shortage of electric energy," must be sudden, unexpected, and demanding of "immediate action."

ii. The Order fails to present facts establishing an emergency under section 202(c) or the Department's regulations

Even taken as complete and accurate claims (which they are not), the factual assertions made in the Order fail to describe an "emergency." The Order does not claim that the retirement of J.H. Campbell was sudden or unexpected. Nor could it. The retirement of J.H. Campbell was carefully planned over a period of years and was approved by the MPSC through a public proceeding. Further, Consumers' plan to retire J.H. Campbell included a commitment to procure replacement resources that improved its capacity position. And Consumers' proposal to retire J.H. Campbell was approved in advance by MISO after a thorough review of its impact on reliability.

Nor did the publication of NERC's 2025 Summer Reliability Assessment in May 2025 transform a long-planned retirement into an event with sudden or unexpected implications requiring immediate action. The Order notes that the 2025 NERC Summer Reliability Assessment characterizes MISO as being at an "elevated risk of operating reserve shortfalls." But NERC's "elevated risk" designation in no way signifies an emergency condition. "Elevated risk," it should be emphasized, falls *below* NERC's highest risk designation: that of "high" risk.[103] NERC's decision not to place MISO in the highest risk category in its Summer Reliability Assessment is

[103] The "High" risk designation refers to a risk of shortfall during normal peak conditions, whereas the "Elevated" risk designation refers to a risk of shortfall during above-normal peak conditions. See Attachment A, NERC, 2025 Summer Reliability Assessment at 6.

in itself powerful evidence that there is no "emergency" stemming from a lack of operating reserves.

The "elevated risk" designation is also far from unusual. In the same report, NERC also designated the systems overseen by SPP, the Electric Reliability Council of Texas (ERCOT), and the New England Independent System Operator (ISO-NE) as at "elevated risk."[104] Except for 2022, when it was designated as "high" risk, MISO has been designated as "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[105] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021.[106] In effect, what the Order implies through its reliance on the NERC report's "elevated" risk designation, is that the fifteen states of MISO – along with large swaths in the rest of the United States – have been in an uninterrupted state of emergency for many years on end. This interpretation, if credited, would effectively read the word "emergency" out of section 202(c).

The Order's hand-waving reference to "potential tight reserve margins" identified in the 2025 NERC Summer Reliability Assessment likewise fails to describe an emergency. The very fact that the Order attempts to rely on "potential" future conditions itself contradicts the notion that MISO is presently facing an

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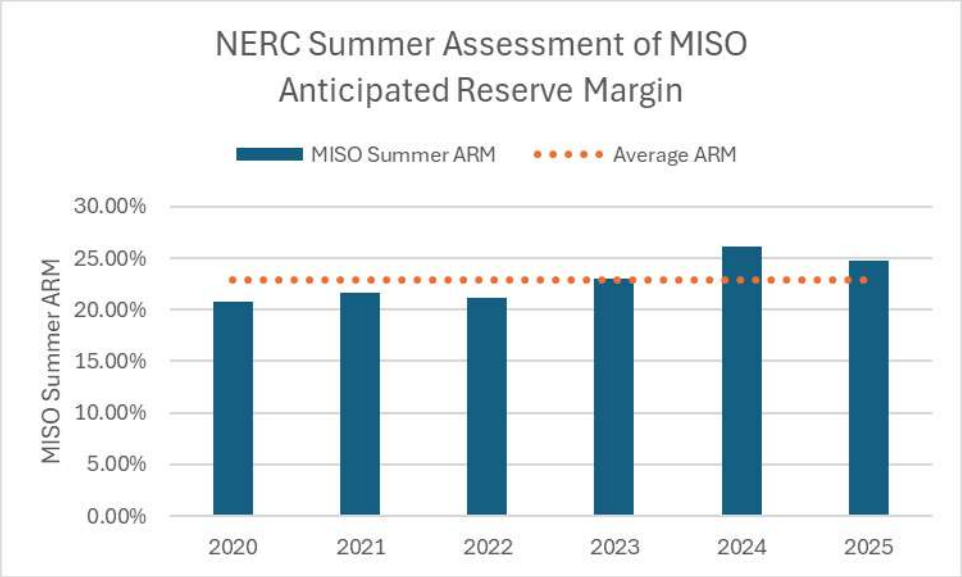
[104] *Id*.

[105] *See* NERC Summer Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

[106] *See* NERC Winter Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

emergency as conceived under section 202(c). Moreover, the actual reserve margins in MISO this summer do not support an emergency determination. The NERC report calculated MISO's anticipated reserve margin for Summer 2025 as 24.7%.[107] This figure substantially exceeds NERC's "Reference Margin Level" for MISO of 15.7%,[108] which is the level that NERC has "established for the areas to meet resource adequacy criteria."[109] MISO's anticipated reserve margin of 24.7% is also *higher* than its average of recent years. The chart below shows the anticipated reserve margin for MISO as calculated in the NERC Summer Reliability Assessment for each year.[110] The chart shows that the 2025 anticipated reserve margin of 24.7% exceeds the 2020-2025 average of 22.9%. Again, the Order has failed to describe a circumstance that is "unexpected," "sudden" or "demanding of immediate attention."



[107] Attachment A, NERC, 2025 Summer Reliability Assessment at 10.
[108] *Id*. at 44.
[109] *Id*. at 15.
[110] *See* NERC Summer Reliability Assessments years 2020 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

The other factual assertions in the Order likewise fail to describe an emergency. The Order devotes one of its few substantive paragraphs to explaining that various generation units have retired in Michigan, reaching back as far as 1997.[111] But generation units retire everywhere as part of the normal, continuous cycle through which old units are replaced with new ones. The unsurprising fact that generation units have retired in Michigan over the last 28 years says nothing about whether there is presently adequate generation in the State, and even less about whether an emergency exists in the region as a whole.

The Order then points to the results of the April 2025 MISO Planning Resource Auction. But these results explicitly contradict the claim that an emergency exists in MISO. The Order acknowledges MISO's conclusion that the auction "demonstrated sufficient capacity." In fact, the Order truncates this quote, which stated in full that: "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."[112] Remarkably, the Order attempts to brush aside the obvious import of this conclusion, preferring instead to focus on the second half of the sentence. But the second half of that sentence merely refers to the fact that the summer price for capacity in MISO, which separates the auction results by season, is high*er* and has a tight*er* supply/demand balance than those of the fall, winter and spring seasons (a fact illustrated by the chart below the header text).

[111] Order at 1.
[112] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 12.

This sentence does not indicate any kind of shortfall in the summer season, much less an emergency shortfall.

The Order also quotes from a slide that states "for North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[113] But this slide is simply noting that the total capacity of resources *offered* into the 2025 auction in the North/Central region was lower than what was offered into the 2024 auction. This slide does not say that the total amount of capacity *procured* in the North/Central region through the auction was inadequate. In other words, this slide is in no way inconsistent with the conclusion in the same report that the "2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels."[114] Further, even as a characterization of the total capacity offered into the auction, the Order ignored a crucial fact in this slide. The slide shows that the reason for the decrease in capacity offered was not because of a decrease in physical generating capacity, but because of a change in the capacity accreditation of various resources—most notably, the very "dispatchable generation" that the order prioritizes. This change in MISO's capacity accreditation methodology occurred over the previous year.[115] The bar chart in Attachment B shows a reduction in accredited capacity for gas and coal of 3.4 GW, which is greater than the overall reduction in offered

[113] *Id*. at 13.
[114] *Id*. at 12.
[115] *Midcontinent Independent System Operator, Inc*., 189 FERC ¶ 61,065 (Oct. 25, 2024).

capacity.[116] In other words, MISO concluded that coal (and gas) resources, such as J.H. Campbell, should be deemed to contribute less to capacity requirements than it had previously assumed.

B. Abusing an Authority Meant for True Emergencies, the Order Intrudes on Authority Reserved to States and to Other Federal Regulators.

i. Resource adequacy is regulated by the states, and by FERC under other provisions of the Federal Power Act

Resource adequacy refers to the capacity of an electric power system to meet demand reliably at all times, including during system peaks and through potential outages. Resource adequacy is "measured at the system level to capture the overall impact of outages of individual components including generators and transmission."[117] Resource adequacy planning is the process by which utilities and system operators, under regulatory supervision, ensure resource adequacy. Resource adequacy planning involves technical and economic considerations that go into determining what resources are added to the grid and which resources should retire and when.

With respect to regulatory oversight for resource adequacy, section 201 of the FPA, 16 U.S.C. § 824(b)(1), reserves authority over generation facilities to the states. It states in pertinent part: "The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over*

[116] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 13.
[117] NREL, Resource Adequacy Basics, available at https://www.nrel.gov/research/resource-adequacy.

facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[118]

Some states have retained this authority over resource adequacy in its entirety.[119] Others have directed their utilities to join RTO/ISOs that, through their tariffs, impose resource adequacy requirements. Those RTO/ISOs also generally establish markets that allow market participants to buy and sell capacity and thereby to facilitate market entry and exit decisions based on price signals. Resource adequacy requirements in RTO/ISO tariffs have been held to be practices affecting wholesale rates subject to the jurisdiction of FERC under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d & 824e.[120]

In Michigan, the regulation of resource adequacy planning has both a state and federal aspect. As a member of MISO, Consumers has a capacity obligation under the MISO tariff. MISO's resource adequacy requirements, however, are designed to be complementary to the primary role of the states in ensuring resource adequacy.[121]

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[118] *Id*. (emphasis added).

[119] *See Devon Power LLC et al.,* 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[120] *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).

[121] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, 62,606 at P 13 (2020) ("approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities ... within the [MISO] region."); *see also id*. ("MISO's proposed Tariff language

Consumers' investment decisions are regulated by the MPSC. Through the state IRP process (described in Section II.C above), the MPSC exercises regulatory authority over Consumers in order to ensure that the utility obtains the amount of capacity it needs to meet its obligations under the MISO tariff, and that it does so at the best value to ratepayers, and with a composition of resources that otherwise complies with state law, including state environmental requirements.

ii. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy

The Order indicates that the Department believes it has the authority to decide which power plants may retire and when, not based on the kind of real emergency that has justified past action, but rather based on its own policy preferences. The Department appears to want to place its own judgment about operating reserve margins ahead of MISO's, and its own preference for which resources are employed to maintain resource adequacy ahead of Michigan's. In effect, the Department appears to read section 202(c) so as to give itself authority to regulate resource adequacy. Any ambiguity on this point was put to rest by the Department's June 13 letter referring cost recovery issues for J.H. Campbell to FERC. In that letter, the Department, through counsel, acknowledged that resource adequacy concerns

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explains that the resource adequacy requirements 'are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction.' In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's Auction is not—*and has never been*—the primary mechanism for its [Load Serving Entities] to procure capacity."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]").

motivated the Order and went so far as to purport to dictate whether J.H. Campbell would be counted as a capacity resource pursuant to the MISO tariff.[122]

Section 202(c) does not provide the Department with the authority it claims. Had Congress intended to vest regulatory authority over resource adequacy in section 202(c), – displacing both state law and sections 205 and 206 of the Federal Power Act, – it would have stated so clearly. But of course it did not. The authorizing language says no more than that DOE may "require by order . . . such generation . . . of electric energy as in its judgment will best meet the emergency and serve the public interest." Indeed, it defies logic that, had Congress intended to empower DOE to be the general decider of which power plants may retire across every utility and independent power producer across the entire country – a function with profound implications for rates, state sovereignty, and a broad array of other stakeholder interests – that Congress would have done so through what may be the only provision in the Federal Power Act that empowers the regulator to act without first assessing the effect on ratepayers or seeking public input, and one of the only provisions that extends to otherwise non-jurisdictional utilities such as public power entities and those in ERCOT.

But even if the text of section 202(c) could, theoretically, be stretched to such an expansive reading (which it cannot), the United States Supreme Court has emphatically rejected statutory interpretations whereby an agency "claim[s] to discover in a long-extant statute an unheralded power representing a transformative

[122] FERC Docket No. EL25-90, submission of Dep't of Energy, June 13, 2025 ("Because the May 23, 2025 Order is predicated on the shortage of facilities for the generation of electric energy and other causes, such as resource adequacy concerns, the Campbell plant shall not be counted as a capacity resource.").

expansion in its regulatory authority."[123] That is exactly what the Department seeks to do here. It seeks to discover in a 90-year-old statute a basis to exercise much broader regulatory authority than it ever has in the past. While it is true, as we explain above in section II.A, that the Department has used section 202(c) to delay power plant retirements on three occasions over the 90-year history, it has always done so at the request of a system operator or governmental body and in a manner narrowly tailored to prevent a concrete and particularized emergency. It has never done so simply to impose its policy preferences ahead of the judgment of those bodies responsible for resource adequacy.

C. The Order Fails to Present Substantial Evidence for its Emergency Determination and Fails to Exercise Reasoned Decision-making by Ignoring Critical Facts.

The Order relies on three sources of evidence for its emergency determination: the NERC 2025 Summer Reliability Assessment, generator retirements in Michigan, and the results of MISO's 2025 Planning Resource Auction. None of these three sources provide evidence that an emergency exists. By relying on these sources, and by misconstruing each of them, the Order fails to exercise reasoned decision-making.

The Order also entirely ignores several other critical facts and considerations. The Order ignores the fact that MISO approved the deactivation of J.H. Campbell. The Order ignores the conclusions of the MPSC proceeding that approved the retirement of J.H. Campbell. And even if it were correct that a capacity shortfall

[123] *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

exists in MISO, the Order fails to explain why preventing the retirement of J.H. Campbell through an emergency measure is necessary to address the shortfall.

i. The Order's discussion of the NERC 2025 Summer Reliability Assessment is unreasoned and incomplete

As explained above in Section IV.A, the Order's discussion of the NERC 2025 Summer Reliability Assessment is both incomplete and unreasoned. Specifically, the Order fails to explain (i) why the NERC report supports an emergency finding for MISO given that NERC did not put MISO in the "high" risk category, (ii) why NERC's designation of MISO as at "elevated" risk provides evidence of a "sudden" or "unexpected" circumstance given that MISO has been at this risk level or higher for years running, and (iii) why the "potential tight reserve margins" identified in the NERC report constitute an emergency given that MISO well exceeds the NERC reference margin level and even exceeds its own average Summer anticipated reserve margin over the 2020 – 2025 period.

ii. The Order's apparent reliance on generator retirements in Michigan is unreasonable

The Order attempts to support its emergency finding by recounting the fact that various power plants have retired in the state of Michigan.[124] As explained above, because power plant retirements are a regular occurrence in the electric power sector, the Order's discussion of this topic fails to present even *prima facie* evidence of an emergency. It also fails to exhibit reasoned decision-making in two key respects. First, it is unreasonable to point to capacity retirements in isolation

[124] Order at 1.

without also considering all the other factors that contribute to resource adequacy. Such factors include capacity additions, changes in load, load shape and load flexibility, demand response, transmission access to external resources, etc. Of course, MISO *did* consider all those factors in the modeling that went into the Attachment Y process through which it approved the deactivation of J.H. Campbell.[125]

Second, the Order fails to explain how power plant retirements in Michigan are related to the emergency the Department purports to identify. In past orders where the Department has used section 202(c) to delay a power plant's retirement, the Department has acted on application of a utility or system operator to address a discrete, localized emergency that would be caused by the impending retirement.[126] The Department makes no such claim to geographic specificity here. Rather, the remainder of the "Emergency Situation" section of the Order appears to describe a purported emergency throughout MISO, insofar as it relies on NERC's general statements about MISO reserve margins and the results of the MISO Planning Resource Auction. Thus, the Order fails to explain why it is relying on power plant retirements in a single state—Michigan—to support its claim that an emergency exists in the region as a whole.

iii. The Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless

[125] *See* MISO Transmission Planning Business Practices Manual, BPM-020-r32 Section 6.2 (Generator Retirement and Suspension Studies and System Support Resources), Section 6.2.3 (Study Scope Development).
[126] *See* Section II.A *supra*.

As explained in Section IV.A above, the Order cites to the MISO planning reserve auction report while ignoring the statement in that report that: "The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels." It is entirely unreasonable for the Department to cite this report as evidence of an emergency when the report has concluded exactly the opposite. The Order's effort to focus on other aspects of the report are equally unreasonable. The unremarkable statement that summer prices are higher than prices in other seasons and therefore reflect a tighter supply/demand balance falls far short of providing evidence for an emergency. Likewise, the Order's reliance on the fact that less capacity was *offered* in the 2025 auction than was offered into the 2024 auction hardly describes an emergency. Further, the Order fails to note the information conveyed in the slide it quotes from, which shows that the only material change between 2024 and 2025 was a result in a change in capacity accreditation values rather than a change in physical resources available.

iv. The Order fails to acknowledge that MISO approved the retirement of J.H. Campbell

As explained in Section II.C above, after a robust, technical, and considered process, MISO approved the retirement of the three J.H. Campbell units pursuant to the study process governed by its tariff. MISO concluded that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria." As the system operator, MISO has more in-depth knowledge of its system than the Department does. The Department should have explained why it reached a

different conclusion than MISO. Instead, the Order failed even to mention that MISO conducted this study and approved the retirement.

v. The Order makes no effort to review the findings of the MPSC or to demonstrate consultation with Michigan as required by 42 U.S.C. § 7113

The Order acknowledges that Consumers acquired the Covert gas plant, but in all other respects fails to acknowledge the MPSC proceeding that approved Consumers' IRP settlement entailing retirement of J.H. Campbell. As explained above in Section II.C, acquiring the Covert gas plant was not the only action Consumers took as part of that IRP. The IRP also delayed the retirement of the peaking units at the Karn facility and included the acquisition of other new resources, with the result that Consumers' capacity position was set to improve materially even after the retirement of J.H. Campbell. The Order also ignores the Michigan capacity demonstration proceedings that found both Consumers and MISO Zone 7 have sufficient capacity resources in 2025 and in the years to come.

Section 103 of the Department of Energy Organization Act, 42 U.S.C. § 7113, provides:

> Whenever any proposed action by the Department conflicts with the energy plan of any State, the Department shall give due consideration to the needs of such State, and where practicable, shall attempt to resolve such conflict through consultations with appropriate State officials.

The Order plainly conflicts with Michigan's energy plan, as reflected in the MPSC's approval of Consumers' IRP. Equally clearly, the Order does not give "due consideration" to the needs of Michigan. Nor does it appear that the Department

made any attempt to resolve the conflict it created through consultation with the appropriate State officials. The Department, therefore, has failed to comply with Section 103 of the Department of Energy Organization Act. A practical consequence of the Department's apparent failure to consult with the State is that the Order lacks basic information related to its action, including the Order's inexplicable failure to accurately state the capacity of J.H. Campbell, the lack of awareness as to the operational status of Unit 2, the understatement of resources Consumers acquired to replace J.H. Campbell, and the omission of any reference to the reliability analysis undertaken by the State.

vi. The Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate

Even accepting the Order's contention that there exists a capacity shortfall in MISO, it does not follow that commanding the continued operation of J.H. Campbell is the best or even an appropriate means of alleviating the shortfall. The Order does not assert that there is a local problem on the grid that only J.H. Campbell can solve. In this respect, the Order departs markedly from past uses of section 202(c) and from the Department's regulations implementing section 202(c), which state that: "Actions under this authority are envisioned as meeting a specific inadequate power supply situation."[127]

Rather, the emergency that the Order purports to identify – "potential tight reserve margins" – is one that spans the entire fifteen-state MISO region and one

[127] 10 C.F.R. § 205.371.

that could presumably be addressed by any number of actions across MISO. And, given that J.H. Campbell amounts to well less than 1% of generation capacity in MISO, there likely were options available that would have had a much greater impact on the overall balance of supply and demand. Further, because J.H. Campbell is an over 60-year-old facility in a largely degraded operational state, there presumably were alternative actions available that could have met the purported need with higher levels of reliability.

Yet the Order does not acknowledge any alternatives or explain whether less burdensome measures were exhausted before taking this action. The question of whether alternative measures could have been used to address the "emergency" is made more challenging by the fact that the Order never quantifies the extent of the emergency it purports to identify within MISO. But that omission merely highlights rather than excuses the deficiencies of the Order.

One possible alternative may have been demand-side measures. The Department's regulations require applicants seeking an order under section 202(c) to provide a "description of any conservation or load reduction actions that have been implemented . . . [and a] discussion of the achieved or expected results."[128] In the Yorktown case, the Department required Dominion to exhaust all demand response measures before dispatching the facility.[129] And yet here the Department failed to make any inquiry or even to consider whether demand-side measures could have

[128] 10 C.F.R. § 205.373.
[129] *See* DOE Order No. 202-17-4 (Sept. 14, 2017) ("PJM and Dominion shall exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Unit 1 or Yorktown Unit 2.")

addressed the purported emergency. Similarly, the Department's regulations require applicants to describe their efforts made to obtain additional power through third parties.[130] But again, the Department failed to consider whether MISO could alleviate the purported emergency through access to external resources.

D. The Department's Direction that MISO Operate J.H. Campbell Using "Economic" Dispatch Is Inconsistent with its Authority under Section 202(c).

The Department's Order directs MISO to "take every step to employ economic dispatch of the Campbell Plant."[131] The Order indicates that the use of economic dispatch is intended to "minimize cost to ratepayers."[132] However, this mandate to MISO exceeds the authority provided by section 202(c). Nor is the use of economic dispatch likely to serve the public interest.

The Order does not define "economic dispatch" or specify how it intends MISO to dispatch the units. In the Energy Policy Act of 2005, Congress adopted a definition of "economic dispatch" that generally conforms to accepted use: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[133] Drawing on this statutory definition, FERC issued a 2006 report, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations,* that provides a useful explanation of the 2-step process that

[130] 10 C.F.R. § 205.373(h).
[131] Order at 2 (Ordering Paragraph A)
[132] *Id.*
[133] *See* section 1234(b) of the Energy Policy Act of 2005, 42 U.S.C. § 16432(b);

regions have, in practice, adopted to implement economic dispatch.[134] This process includes (1) *day ahead unit commitment*, in which grid operators commit generators to be online in the subsequent 24-hour period, determined based on which generators will be most economic, taking into account each unit's physical operating characteristics, and (2) *unit dispatch*, in which grid operators dispatch committed resources at specified levels, in real-time, determined based on what set of units will minimize total system costs, given actual load, generation, and transmission conditions and constraints.[135]

Section 202(c) authorizes DOE to direct certain actions during emergency conditions. As relevant here, section 202(c)(1) provides DOE with "authority . . . to require by order . . . such generation . . . of electric energy as in its judgment will *best meet the emergency* and serve the public interest." In other words, DOE's power extends only to ordering actions that meet the emergency that the Department has identified.

But economic dispatch is not a rational response to the types of emergencies that section 202(c) authorizes DOE to address. Nor would economic dispatch be a rational approach to addressing the circumstance that DOE is purporting to address with its order—a potential capacity shortfall—if that were within its authority under section 202(c). In fact, DOE has made no effort to explain why economic dispatch is a rational remedy here, — let alone the best means of meeting the "emergency" that it

[134] FERC, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations* (July 31, 2006), https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.
[135] *Id.* at 5-6.

has identified. And, unlike prior Orders, here DOE acted on its own motion without a request or input of MISO and so cannot rely on the expertise of the cognizant grid operator or operating utility requesting a specific remedy to justify the appropriateness of economic dispatch.[136]

i. Economic dispatch is not a rational response to a shortage of electric energy

Economic dispatch is the standard procedure by which operators (such as MISO) operate the grid. However, outside of normal operations, including during emergency conditions, generation units may be selected "out of merit order" as necessary to ensure that generation and load are balanced. Operating a unit pursuant to economic dispatch is, necessarily, inconsistent with operating the unit in a manner designed to address an emergency, such as a shortage of electric energy. If a unit would be dispatched under purely economic conditions, but electric demand can alternatively be met with other existing supply (or demand response) resources, that unit is *not* necessary to meet the emergency. However, if the unit would, in fact, be needed to address a shortage, it should be dispatched regardless of whether its offer price is above or below the market-clearing price. In other words, economic dispatch is not a dispatch rule that is reasonably tailored to ensure that the unit addresses a shortage of electric energy.

[136] *See* DOE Order No. 202-18-1 at 4 (The statute requires only that the Secretary use his or her best judgment to meet the emergency and serve the public interest. In this situation, the expertise of the applicant was an important factor. The Department received an application from PJM, which . . . holds the highest-level, federally-regulated reliability responsibilities for the system it manages.), https://www.energy.gov/sites/prod/files/2017/11/f46/Summary%20of%20Findings%20Order%20No.%202-18-1.pdf.

Prior DOE orders have contained significant operating constraints to satisfy this statutory requirement. Orders have specified that units subject to a section 202(c) order should only run in specific emergency alert conditions — specific conditions in which grid operators have exhausted the capacity of other available generators, imports, and voluntary demand response, and failure to call on additional generation will risk involuntary load shed.[137] Similarly, in its order to delay retirement of the Yorktown plant, DOE recognized that dispatch of the units must be constrained, that continued operation of the units under the standard methodologies used by the local utility (Dominion Energy Virginia) and grid operator (PJM) would not be appropriate, and that Dominion and PJM must exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2.[138] Similarly, in the case of its 2005 District of Columbia Department of Public Service order, the Department directed Mirant to maintain its facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[139] And in its 2017 order regarding GRDA's Grand River Energy Center

[137] DOE Order No. 202-21-1 (authorizing operation only during Energy Emergency Alert Level 2 or Level 3); DOE Order No. 202-21-2 (authorizing operation only during Energy Emergency Alert Level 2 or higher); DOE Order 202-22-1 (same); DOE Order No. 202-22-3 (same); DOE Order No. 202-22-4 (same).

[138] DOE Order No. 202-17-2 (providing that Yorktown units 1 and 2 may be dispatched "only when called upon to address reliability needs" and directing PJM and Dominion Energy Virginia "to provide the dispatch methodology to the Department upon implementation, and to report all dates on which Yorktown Units 1 and 2 are operated"); DOE Order No. 202-18-1 at 3 (relying on the fact that DOE "require[d] PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2").

[139] DOE Order No. 202-05-3 (Dec. 20, 2005), District of Columbia Public Service Commission at 10 – 11.

Unit 1, the Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[140] DOE's Order contains no such constraints, and it fails to explain or justify such deviation from consistent past practice.

ii. Economic dispatch is an arbitrary response to any alleged capacity shortage

Indeed, even on DOE's own terms, the justification for the Order does not support ordering J.H. Campbell to operate whenever MISO's economic dispatch rules would select it to operate. The Order points specifically to questions about the sufficiency of electric *capacity* and the ability of MISO to meet load during periods of high demand and low resource output over the next 90 days as the basis for its emergency determination.[141] For example, the Order points to NERC's 2025 Summer Reliability Assessment, and specifically to the finding that "MISO is at elevated risk of operating reserve shortfalls *during periods of high demand and low resource output*."[142] The order repeatedly raises concern about the risk of "*capacity* shortfall for MISO," the extent to which *capacity* of certain generating resources have retired or may retire, and that MISOs' *capacity* market auction (the Planning Resource Auction Results for Planning Year 2025-26) "reinforce the need to increase *capacity*."[143] Dispatch of J.H. Campbell at any time other than a specifically identified operating reserve shortfall (e.g., a concrete expected supply/demand imbalance)—let

[140] DOE Order No. 202-17-1 at 2.
[141] Order at 1-2
[142] Order at 1 (emphasis added).
[143] Order at 1-2.

alone dispatch whenever the plant would be called upon by MISO's economic dispatch algorithm—is *not* necessary to address the type of emergency that the DOE order identifies. Even if the order sufficiently justified retention of J.H. Campbell as a capacity resource (which it does not for the reasons outlined above), it would not follow that J.H. Campbell's electric *energy* is needed to address the identified emergency. Given the nature of the alleged emergency identified in the Order, no dispatch from J.H. Campbell should be necessary unless and until called upon by MISO expressly to address an emergency purpose.

iii. "Economic dispatch" is not in the public interest in this case

Section 202(c) also requires that DOE determine that a given remedy is in the public interest.[144] The public interest determination is not an independent or sufficient criteria to order any particular action. Rather, Congress's use of the conjunctive "and" in section 202(c)(1) clearly prohibits DOE from ordering actions that the Department believes will advance the public interest if those actions exceed what is needed to address the identified emergency. In fact, DOE acknowledged this limit on its authority in its order denying rehearing of its order directing the retention of the Yorktown power plant.[145] Therefore, for the reasons explained above, economic dispatch is not appropriate even *if* DOE determines that it would advance the public interest.

However, DOE's vague direction to MISO to operate Campbell using "economic dispatch" will not further the public interest. DOE's order does not explain why it

[144] 16 USC § 824a (c)(1).
[145] DOE Order 202-18-1 at 4.

believes economic dispatch would be in the public interest, other than a general reference to "minimize[ing] cost to ratepayers." However, this justification fails for two reasons. First, the Order's reference to economic dispatch is ambiguous and leaves open the likelihood that Consumers will operate the facility even at times when its operation will have the effect of *increasing* costs to consumers. For example, Consumers is likely to commit J.H. Campbell into MISO's day ahead electricity market as a "must run" unit, rather than using Emergency commitment.[146] In other words, Consumers will operate the units at least at minimum load every day rather than when there is a forecasted shortfall (e.g., due to unexpected load, unit outage, or a natural disaster). In such circumstances, J.H. Campbell will run at its minimum operational level regardless of whether doing so is truly economic. As a result, DOE has not justified, and cannot be reasonably certain, that economic dispatch will "minimize cost to ratepayers" — its sole explanation for the operational profile it has directed MISO to adopt. In other words, DOE's ordering of economic dispatch in this case is arbitrary.

Moreover, by directing economic dispatch, rather than reserving J.H. Campbell for discrete supply shortages by committing it as Emergency status, DOE's order will result in the facility operating significantly more than necessary. Because J.H. Campbell is old, and because Consumers has been deferring maintenance in anticipation of its retirement, a significant step-up in operation caused by must-run commitment and economic dispatch will increase the likelihood that one or more

[146] *See* MISO Tariff, Section 39.2.5.b.xxvi (discussing Emergency Commitment Status).

units break, requiring costly maintenance to continue operating. Such repairs would likely further increase costs to ratepayers—costs that would be less likely to occur under an operational order better tailored to the emergency that DOE has identified. For example, DOE could have minimized the risk of ratepayer costs had it directed Consumers and MISO to commit (and ultimately dispatch) the facility only after analysis showing a likely near-term supply/demand imbalance or short-term emergency conditions (such as a heatwave, or the forced outage of a large generator or transmission line). The Order is arbitrary and capricious by ordering operation that risks increasing costs to ratepayers, the very outcome DOE has said it is looking to avoid.

Second, the Order fails to consider, let alone explain away, the fact that the State of Michigan has made an independent judgment that it would be in the best interest of ratepayers, the state, and the environment, to accept Consumers' proposal to retire J.H. Campbell. As explained above, the State of Michigan and MISO each went through robust processes to assess the need for J.H. Campbell (or lack thereof), as well as the economic and environmental impacts of its continued operation. The State of Michigan appears not to have been consulted on DOE's Order, notwithstanding the extensive process that it underwent to evaluate whether retirement would be in the public interest. Here, the public interest is best effectuated by respecting the Michigan's considered decision to approve the closure of J.H. Campbell plant, rather than to allow its near continuous operation at ratepayer expense.

Finally, for the reasons explained more fully below, the Order fails to consider the increased air and water pollution that will be caused by J.H. Campbell operating pursuant to economic dispatch instructions. DOE fails to even consider these harms, let alone weigh them against the (alleged) benefits of increased operation, in its determination that economic dispatch of the J.H. Campbell plant will further the public interest.

E. The Department failed to limit its remedy as required by 202(c)(2).

Section 202(c) imposes strict substantive limits on the Department's authority to issue emergency orders that may result in conflicts with any Federal, State, or local environmental law or regulation. Congress deliberately included these limitations to prevent section 202(c) from becoming a de facto exemption from environmental regulation. Here, DOE failed to comply with either of the statute's two express constraints and therefore acted unlawfully.

i. Section 202(c)(2) contains two distinct and binding legal constraints

Congress imposed two critical limitations on the scope of a DOE emergency order under section 202(c):

Temporal Constraint. First, DOE must "ensure that such order requires generation . . . of electric energy only during hours necessary to meet the emergency and serve the public interest."[147] Again, this is a conjunctive requirement such that both conditions—operation in a given hour must be necessary to meet the emergency

[147] 16 U.S.C. § 824a(c)(2).

and operation in a given hour must serve the public interest—must be satisfied.[148] Moreover, by referring to the "hours" necessary to meet the emergency, Congress placed a high burden on DOE to demonstrate that the remedy provided was narrowly tailored to the specifics of the emergency that the order is designed to address.

Environmental Constraint. Second, the Department must "ensure that such order . . ., to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts."[149]

The Department acknowledges that, "additional generation may result in a conflict with environmental standards and requirements" and so it is required to limit additional generation from J.H. Campbell. However, the Order then wholly fails to meet the acknowledged temporal and environmental constraints in the particular ordering conditions that it establishes.

ii. The Order violates Section 202(c)(2)'s temporal constraint

The Order states that its direction to Campbell is "limited in duration to align with the emergency circumstances."[150] But, in fact, DOE has directed the unit to operate for the entire statutory maximum of 90 days. And, as described in more detail *supra,* within that 90-day window, DOE has directed the use of "economic dispatch"—an operational direction that will likely result in Campbell operating at least at its

[148] DOE Order No. 202-18-1, 4(Nov. 6, 2017).
[149] 16 U.S.C. § 824a(c)(2).
[150] Order at 2.

minimum output level, and more likely at the maximum output Consumers Energy can manage, taking into account the state of the facility, continuously for the 90-day period—without providing any other temporal limitation on operations. In other words, the Order appears to assume, without explanation, that an emergency will exist in every hour over the entire 90-day period of the Order that Consumers happens to submit a bid into MISO's energy auction that is lower than the market-clearing price.[151] There is no reason to expect that this will actually be the case.

For these and all the reasons explained in section IV.C, the Order's direction that MISO dispatch J.H. Campbell economically is flatly inconsistent with section 202(c)'s requirement that emergency orders be limited to "only" those "hours" in which operation is necessary to meet the emergency. DOE cannot transform an hour-by-hour limitation into a blanket summer-season waiver through hand-waving at "elevated risk" of tight operating reserves and "*potential* electricity shortfalls."

DOE's failure to limit dispatch to discrete periods when the generation is needed to address the purported emergency renders the Order unlawful under the plain terms of § 202(c).

iii. The Order violates section 202(c)(2)'s environmental constraint

Section 202(c)(2) also requires DOE to ensure, "to the maximum extent practicable," that its orders (1) are consistent with applicable environmental laws and

[151] In fact, it is not clear that DOE will limit operation to 90 days. DOE is authorized to extend the Order beyond 90 days under section 202(c), 16 U.S.C. § 824a(c)(4)(A), and has made no representation that the "emergency" is likely to be resolved by the end of the 90-day period.

regulations and (2) "minimize any adverse environmental impacts." The Department makes no serious effort to comply with this mandate.

First, the Order contains no analysis of J.H. Campbell's environmental obligations. J.H. Campbell is subject to air pollution requirements limiting its emissions of SO_2, NO_x, particulate matter, and mercury, and mandates the use of pollution control equipment such as baghouses, dry sorbent injection, and activated carbon injection systems.[152] DOE does not reference these requirements, direct Consumers to optimize the use of pollution controls or avoid operation during air quality episodes (even if those episodes occur at a time when the marginal energy from J.H. Campbell is not needed to meet electric demand), or provide any guidance for how Consumers is to operate the facility in the event that these requirements would come in conflict with its ability to provide power at any given time. It does not clarify what steps Consumers Energy would have to take to ensure continued operation of pollution control equipment in the event such equipment malfunctioned during the 90-day period. Nor does it appear the Department consulted with the State of Michigan, including its environmental regulator, to identify mechanisms to allow J.H. Campbell to remain available in a way that would minimize conflicts with state environmental laws, which the State was uniquely positioned to advise on and which

[152] *See* Michigan Department of Environment, Great Lakes, and Energy, Renewable Operating Permit Issued to Consumers Energy, J.H. Campbell Generating Complex [J.H. Campbell ROP] (July 2, 2021), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal, and also accessible at https://www.egle.state.mi.us/aps/downloads/rop/pub_ntce/B2835/B2835%20FINAL%2007-01-21.pdf.

is required by section 103 of the Department of Energy Organization Act.[153] Instead, the Order offers only generic language about "compliance with applicable requirements… to the maximum extent feasible."

Second, the Order does not establish any operational criteria to "minimize any adverse environmental impacts" as required by section 202(c)(2). This requirement is in addition to the direction to minimize conflicts between operations and environmental requirements. It makes clear that Congress intended DOE to go beyond just avoiding regulatory conflicts but to proactively consider the environmental impact of its emergency orders. But DOE did not design its order to minimize environmental impacts of continued operation of J.H. Campbell. In fact, DOE's order runs directly contrary to the objective of minimizing environmental impacts by expressly directing MISO to operate J.H. Campbell on an "economic dispatch" basis. That instruction prioritizes low-cost dispatch irrespective of environmental impact.

F. The Order Violates NEPA.

Orders issued under section 202(c) are major federal actions subject to NEPA.[154] Such orders direct federal interventions that may affect environmental conditions. The direction to continue operation of J.H. Campbell is unquestionably a major action that significantly affects the environment. Continued operation of J.H. Campbell will result in significant increases of air and water pollution compared to a

[153] *See* 42 U.S.C. § 7113.
[154] 42 U.S.C. § 4336e(10) (defining a "major federal action" as one in which the agency carrying out such action determines subject to substantial Federal control and responsibility.").

scenario in which Campbell retired as planned.[155] In fact, the Order directly concedes this point, stating "the additional generation may result in a conflict with environmental standards and requirements."[156]

For any DOE action affecting the quality of the environment, DOE must comply with NEPA—including through issuance of an environmental impact statement, environmental assessment, categorical exclusion, or special environmental analysis.[157] DOE has not taken, or even initiated, any such action. As such, it is acting contrary to its own NEPA regulations and to its obligations under NEPA.

DOE has previously sought to comply with NEPA for section 202(c) orders through categorical exclusions or special environmental assessments. Neither have been undertaken in this instance. Moreover, neither would be applicable here.

DOE has previously pointed to categorical exclusion B4.4 for "power management activities." However, that categorical exclusion is applicable only "provided that the operations of generating projects would remain within normal operating limits." Here, the Order explicitly authorizes the J.H. Campbell plant to operate beyond its normal permitted limits. Consequently, neither categorical exclusion B4.4, nor any other available exclusion, applies.

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[155] *See* J.H. Campbell ROP, *supra* n. 152; State of Michigan Department of Environmental Quality, Authorization to Discharge Under the National Pollutant Discharge Elimination System, Permit No. MI0001422 (May 29, 2018), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal.
[156] Order at 2.
[157] *See* 10 C.F.R. § 1021.102(b).

More recently, DOE has, on certain occasions, relied on emergency provisions that can excuse agencies from preparing environmental documents before taking such actions,[158] and instead prepared after-the-fact Special Environmental Analyses in the event that an order results in a significant effect on the environment.[159] However, these instances involved sudden emergencies that provided DOE substantially less notice compared to the months or years of advance warning DOE received regarding J.H Campbell's scheduled retirement. In this case, DOE acted in response to circumstances known well in advance: the long-scheduled retirement of J.H. Campbell on May 31, 2025. Given considerable lead time, DOE had ample opportunity to prepare, at a minimum, an EA prior to issuing its Order. DOE's failure to initiate any environmental review thus lacks justification.

Moreover, there will be even less justification for a failure to initiate appropriate environmental review for any extension of the Order beyond the initial 90 days. Under section 202(c)(3), orders conflicting with environmental laws are strictly limited to 90 days but may be extended. However, such extension requires consultation with other federal agencies responsible for regulating or with expertise in such environmental impacts.[160] Any justification that NEPA can be sidestepped to

[158] *See* 10 C.F.R. § 1021.343(a); 40 C.F.R. § 1506.12.
[159] *See* DOE, Air Quality and Environmental Justice Memorandum (2021), https://www.energy.gov/sites/default/files/2022-01/sea-05-ercot-air-quality-and-ej-analysis-2021-07-21.pdf; DOE, Special Environmental Analysis for Actions Taken Under U.S Department of Energy Emergency Orders Regarding Operation of the Potomac River Generating Station in Alexandria Virginia (2006), https://www.energy.gov/sites/default/files/nepapub/nepa_documents/RedDont/SEA-04-2006.pdf
[160] 16 U.S.C. § 824a(c)(4)(B).

address an emergency need fades as DOE's orders extend beyond the initial 90-day period.

V. CONCLUSION

For the foregoing reasons, the Michigan Attorney General's request for rehearing should be granted.

Dana Nessel
Michigan Attorney General

Michael E. Moody

Digitally signed by Michael E. Moody
Date: 2025.06.18 16:14:42 -04'00'

Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

Dated: June 18, 2025

Attachment A

2025 NERC Summer Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025

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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is spans six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA*), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA*. Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's 2024 *State of Reliability* report

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

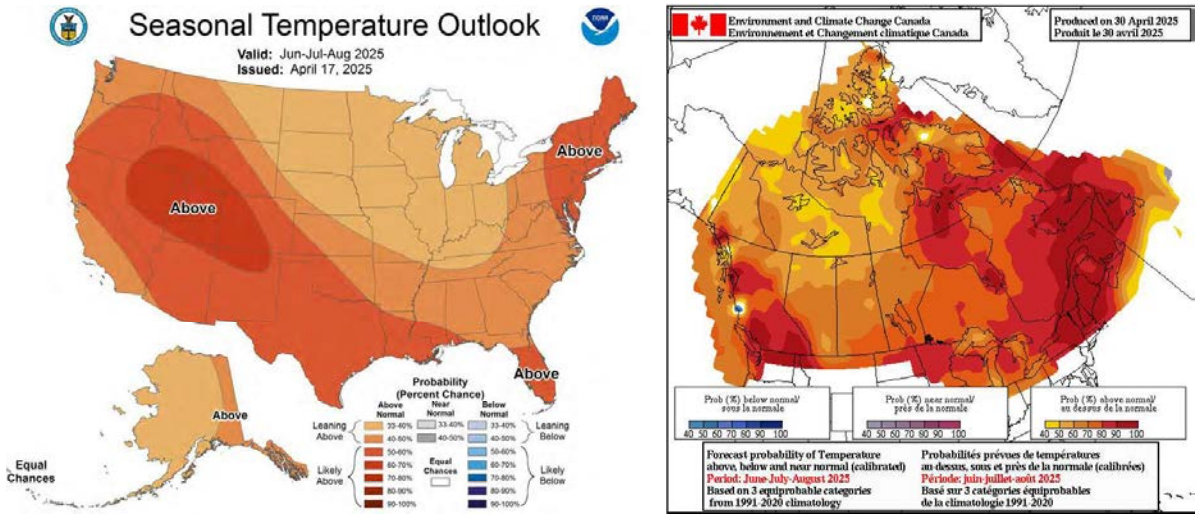


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 1.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 2.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

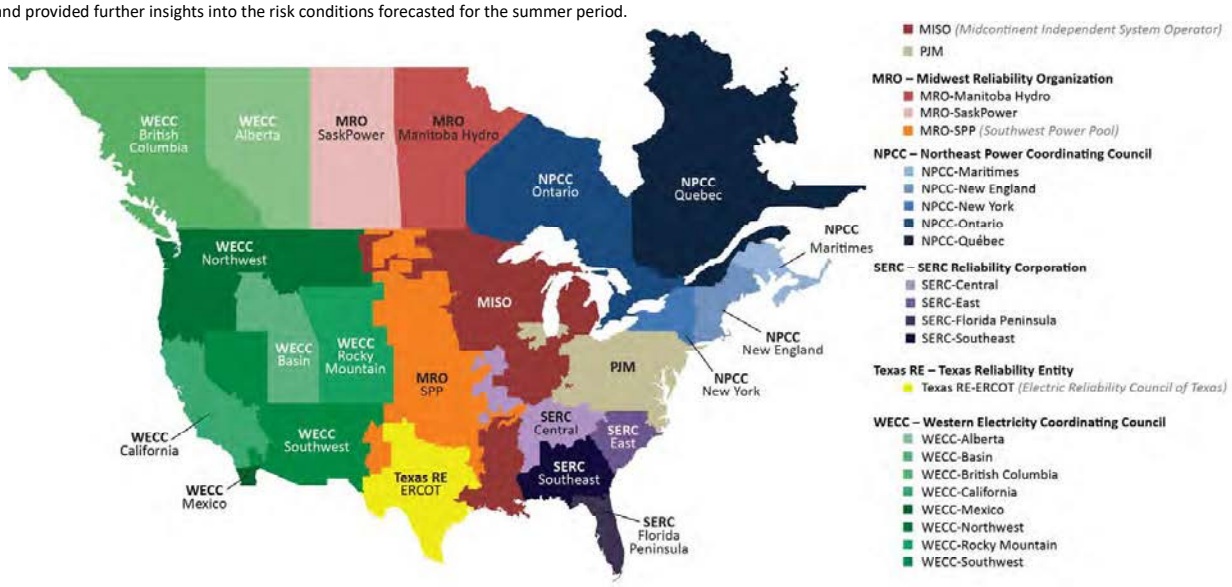
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central SERC-East SERC-Florida Peninsula SERC-Southeast	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



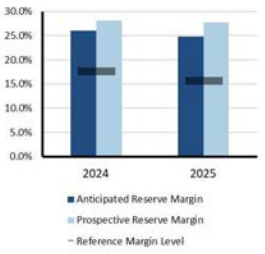
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

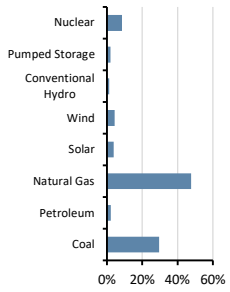
On-Peak Reserve Margin



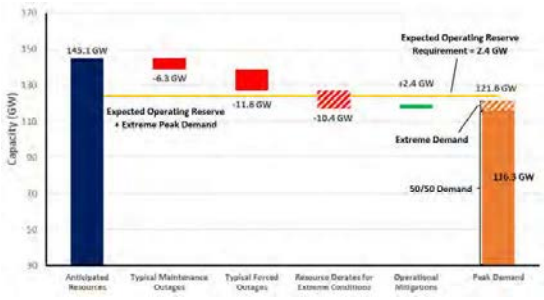
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions

MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

Highlights

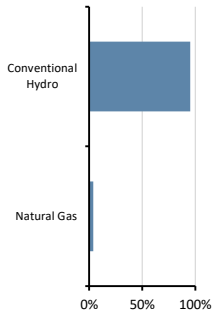
- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

Risk Scenario Summary

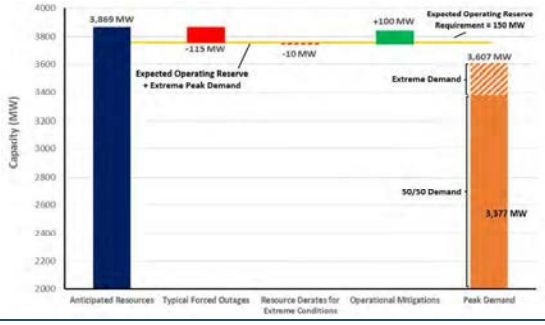
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

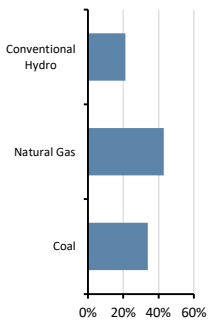
- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

Risk Scenario Summary

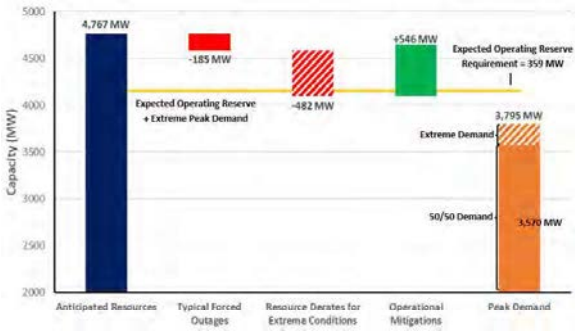
Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice

MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Highlights

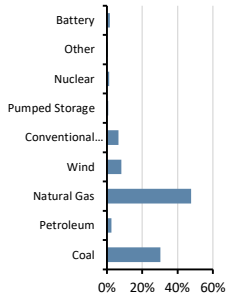
- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

Risk Scenario Summary

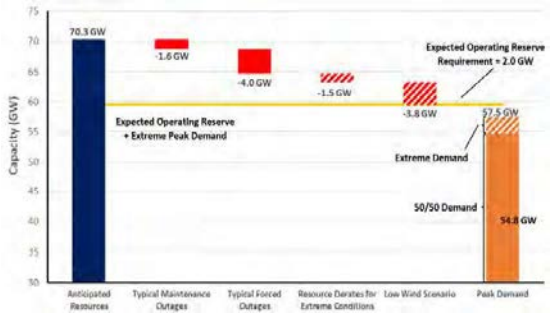
Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

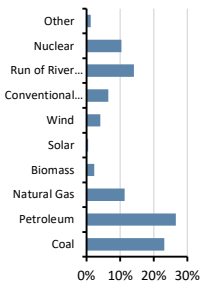
- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

Risk Scenario Summary

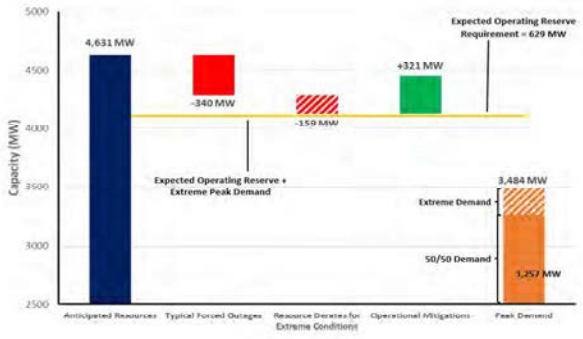
Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)

NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

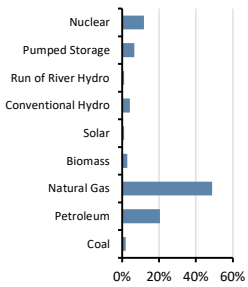
- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

On-Peak Reserve Margin

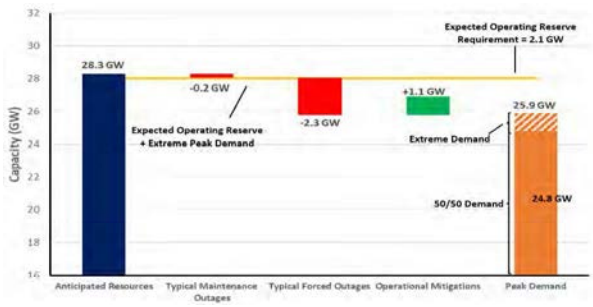
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

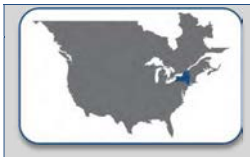
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

Highlights

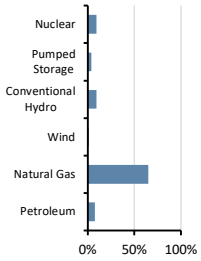
- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

Risk Scenario Summary

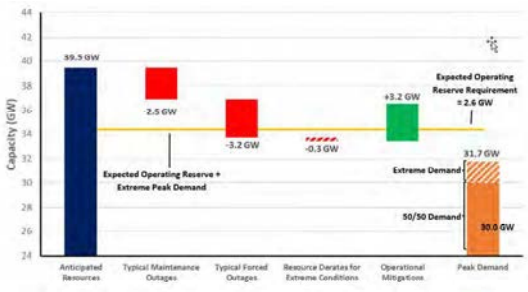
Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual

NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

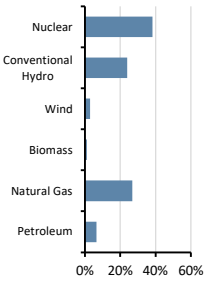
- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

Risk Scenario Summary

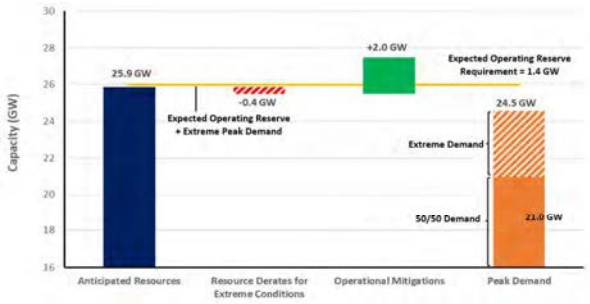
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.

NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

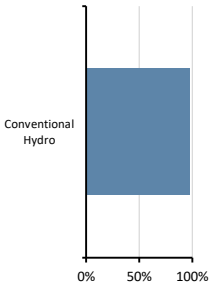
- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

Risk Scenario Summary

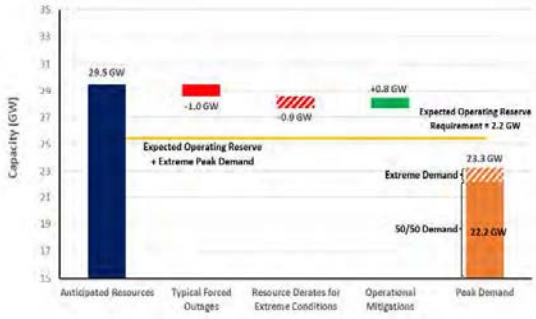
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.

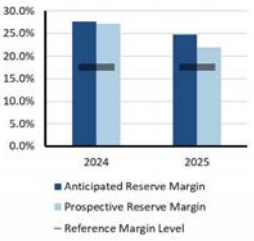
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

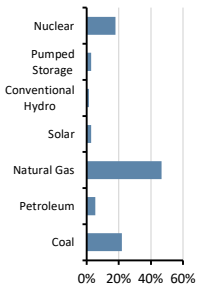
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

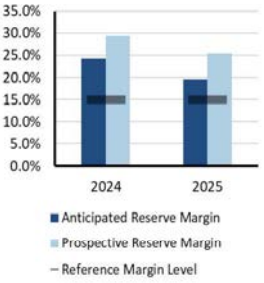
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

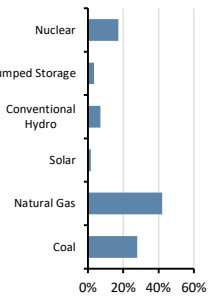
On-Peak Reserve Margin



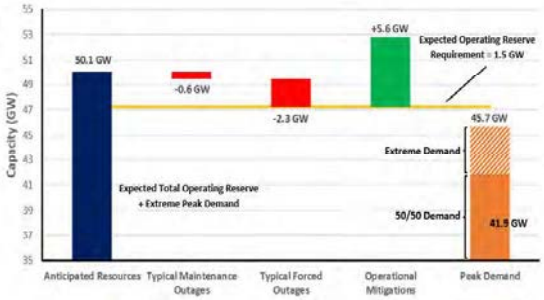
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures

SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

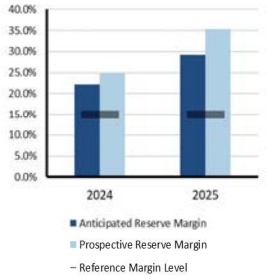
Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

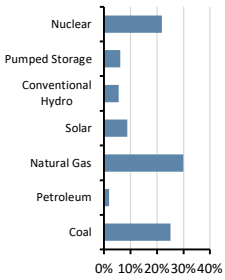
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures

SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

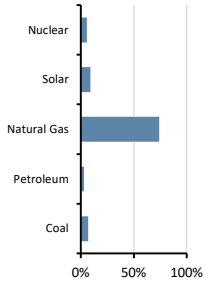
- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

On-Peak Reserve Margin

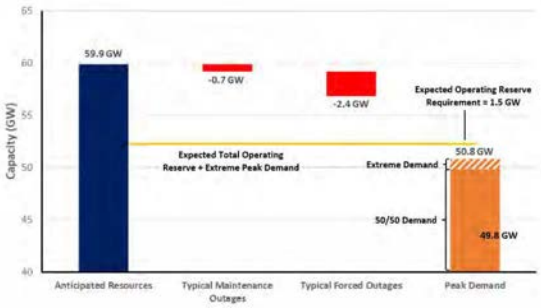
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

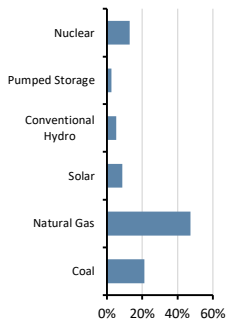
- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

On-Peak Reserve Margin

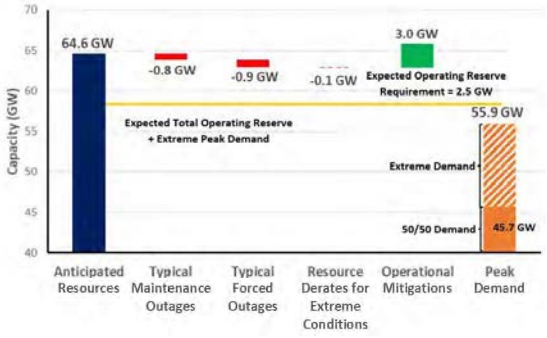
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

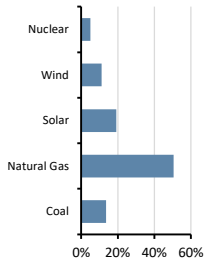
- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

Risk Scenario Summary

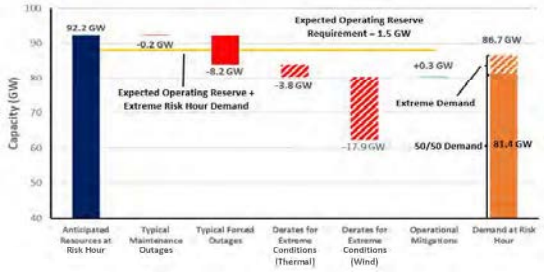
Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports

WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

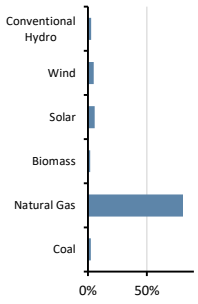
- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

Risk Scenario Summary

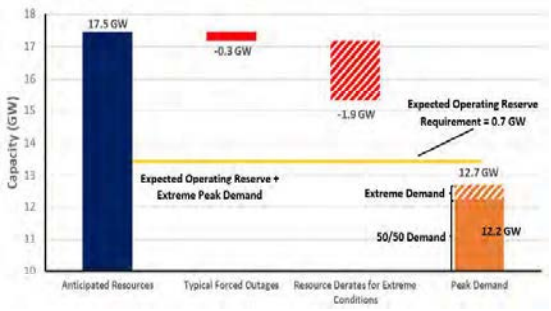
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

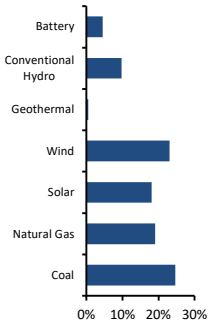
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios with imports.

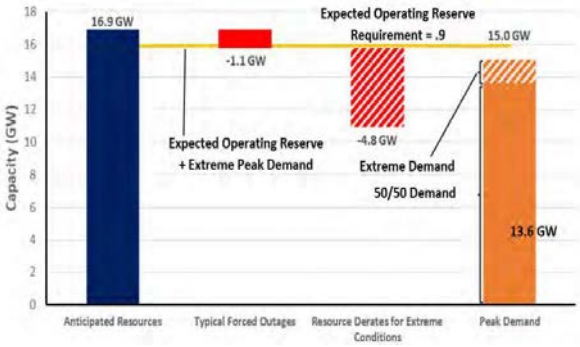
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

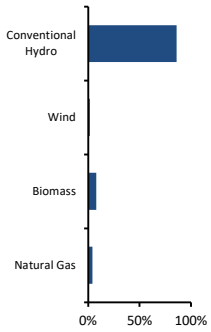
- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

Risk Scenario Summary

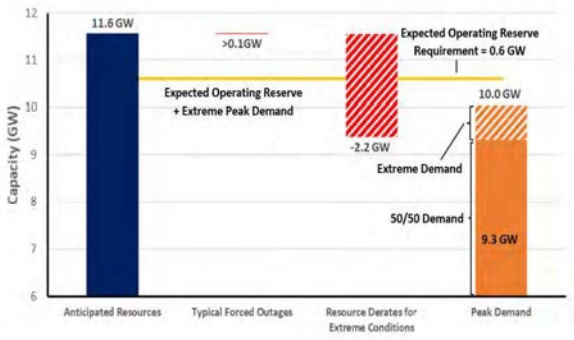
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-California

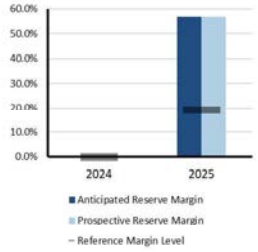
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

On-Peak Reserve Margin

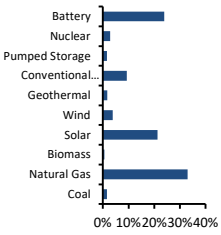
(Note: year comparison not available)



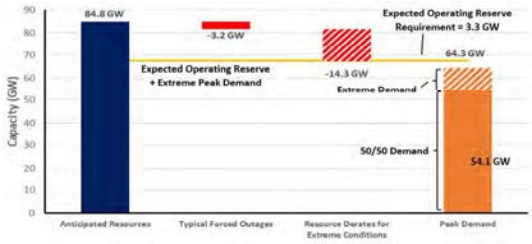
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages

WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

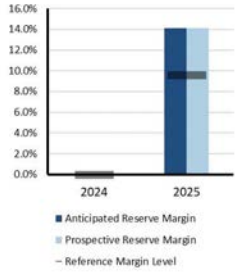
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

Risk Scenario Summary

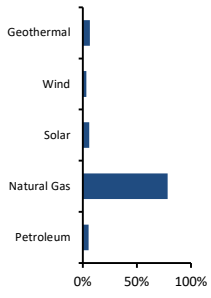
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

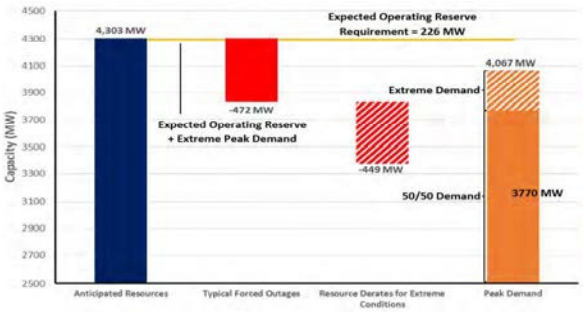
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

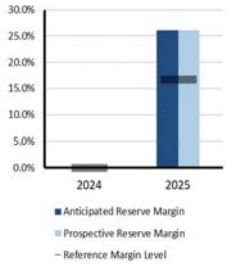
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

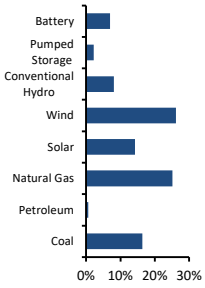
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

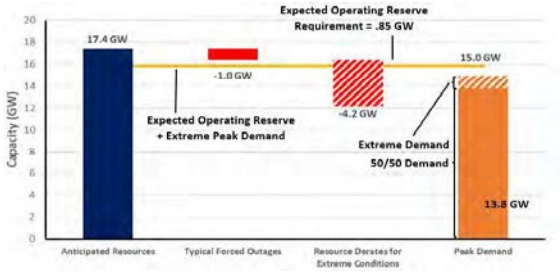


(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA*.

Highlights

- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

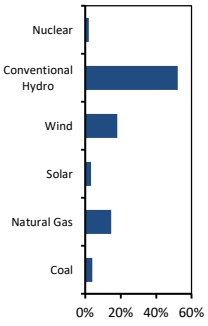
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

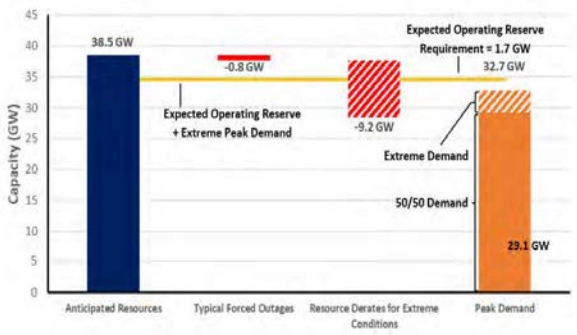
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

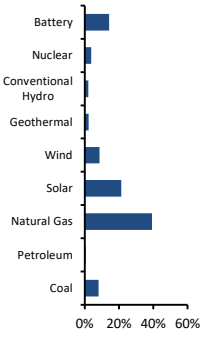
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

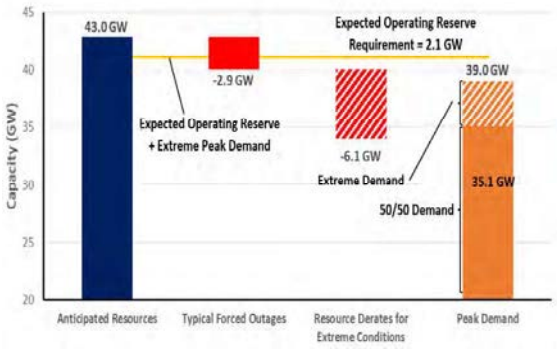
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[12] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[13] The summer season represents June–September and the winter season represents December–February.

[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the summer 2025 as shown in **Figure 4**.

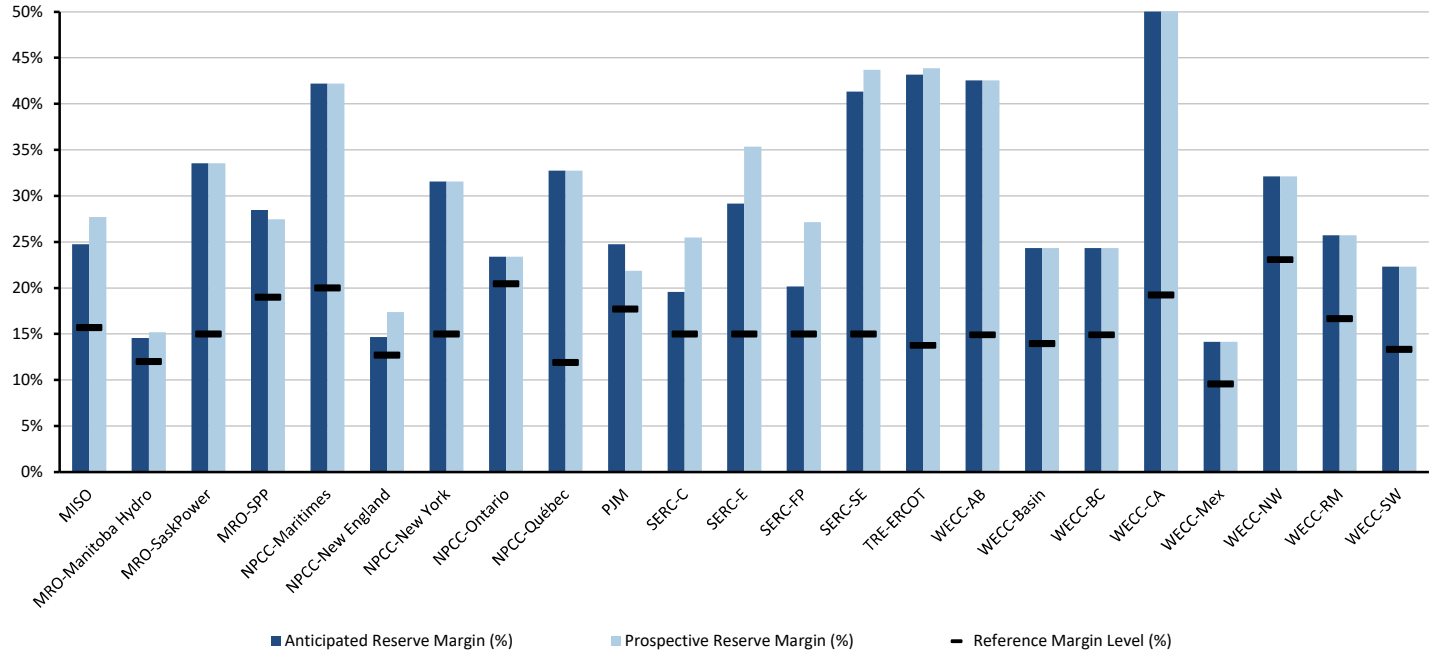


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

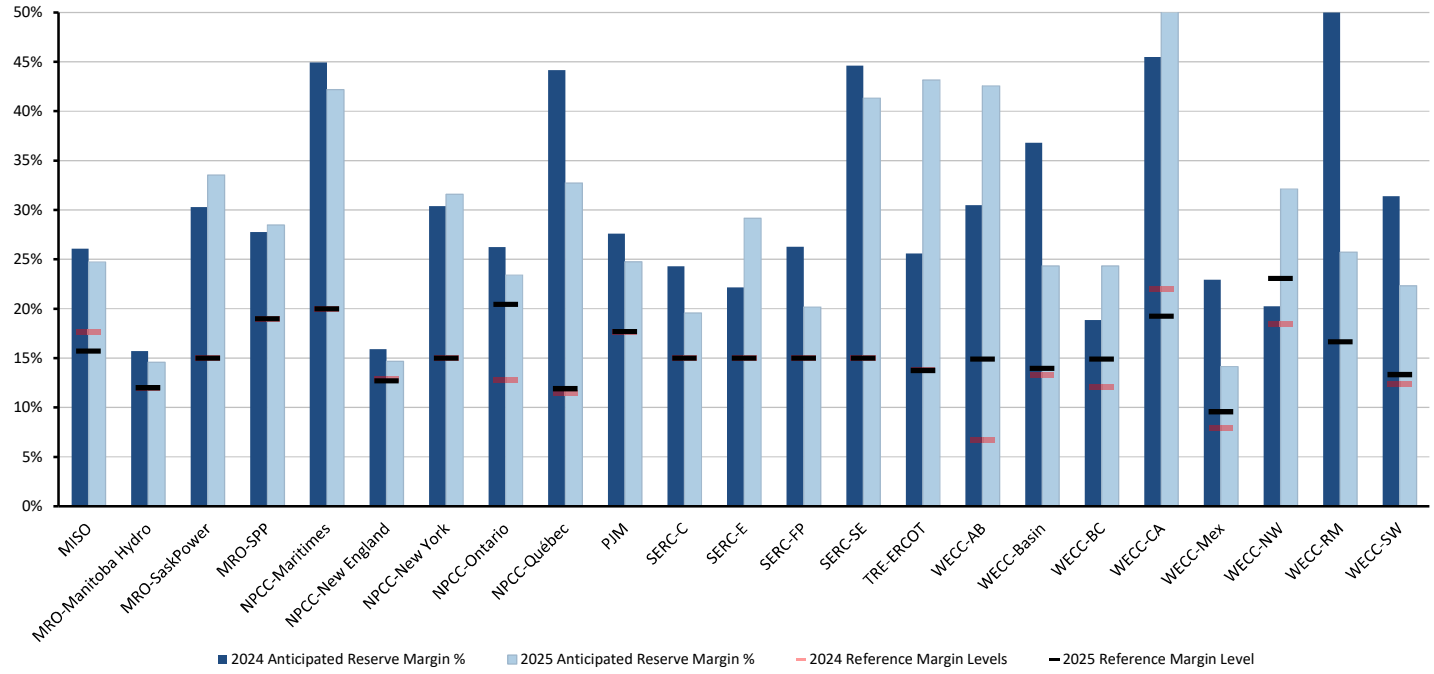


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

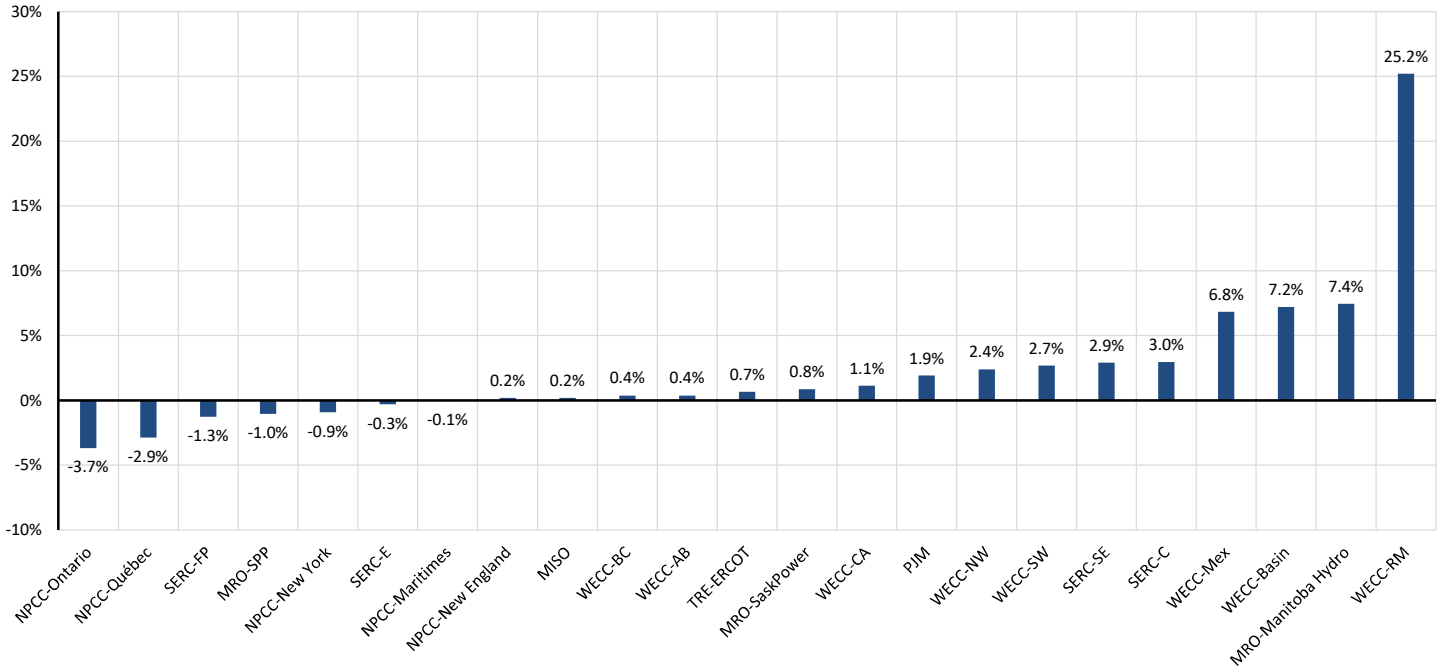


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	175,081	34,774	20%	142,014	86,170	61%	101,959	65,290	64%	36,311	32,298	89%

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta's demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.
[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2024 SRA*.
[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.
*Values include both maintenance and forced outages.
**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Attachment B

MISO 2025 PRA Report

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…

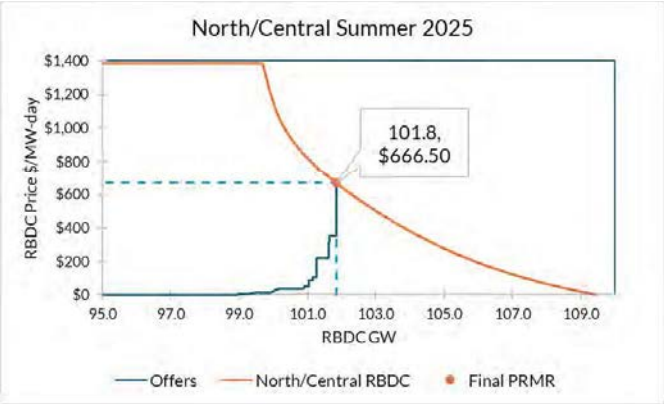
- Delivers competitive prices aligned with seasonal risks and tightening surplus
  - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
  - Clears capacity above target Planning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

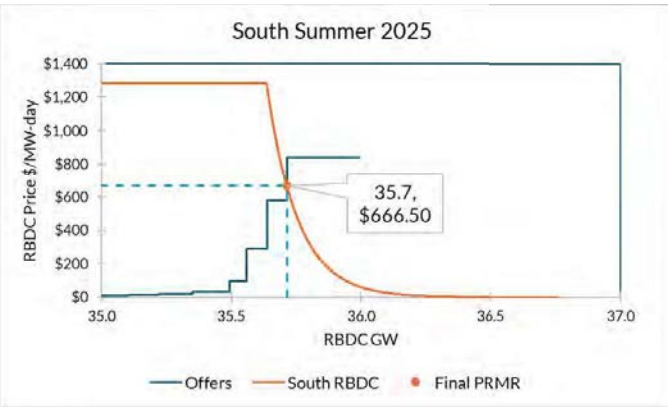
Why it Matters

- 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

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

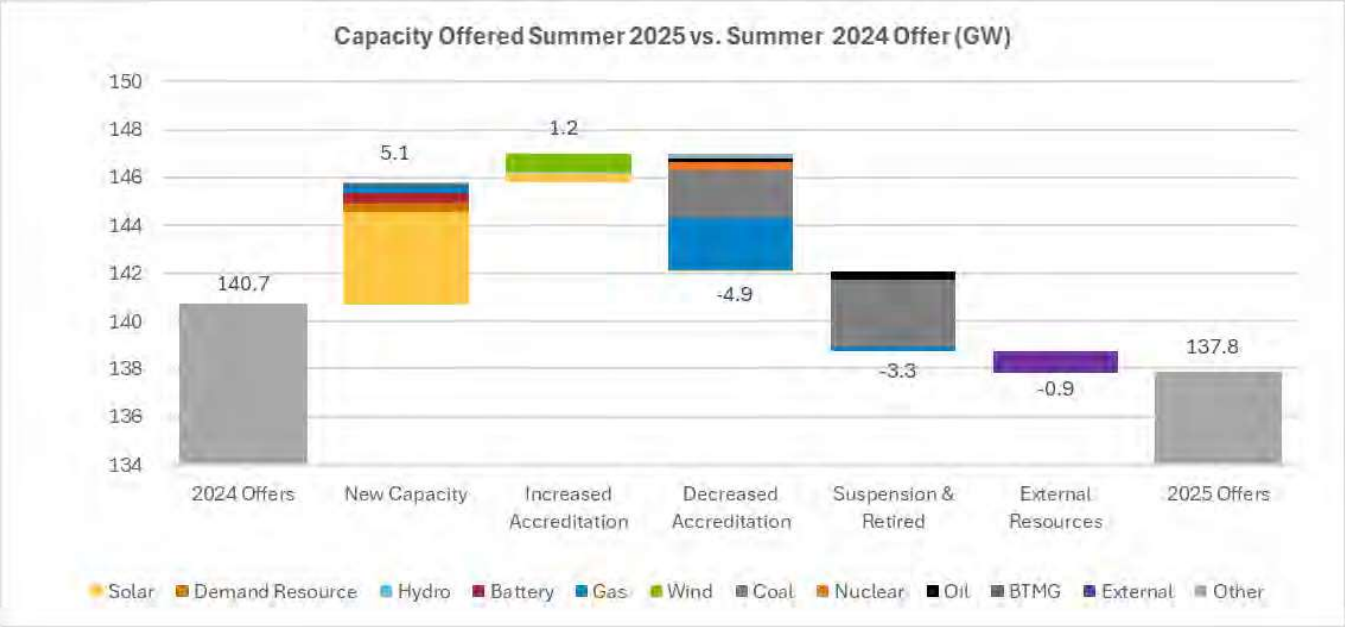
- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

	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

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

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

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

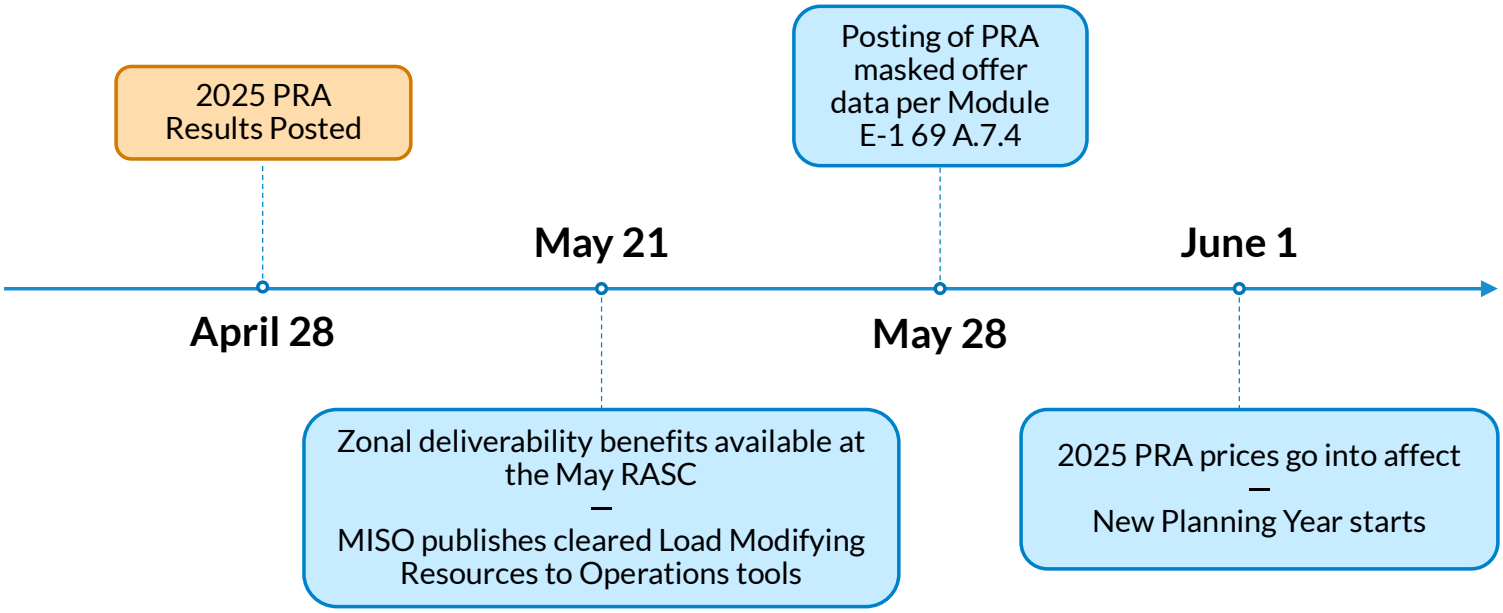
- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025)*
- ✓ Approved over $30 billion in new transmission 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

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

Next Steps


2025 PRA Results Posted
Posting of PRA masked offer data per Module E-1 69 A.7.4
April 28
May 21
May 28
June 1
Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools
2025 PRA prices go into affect
—
New Planning Year starts

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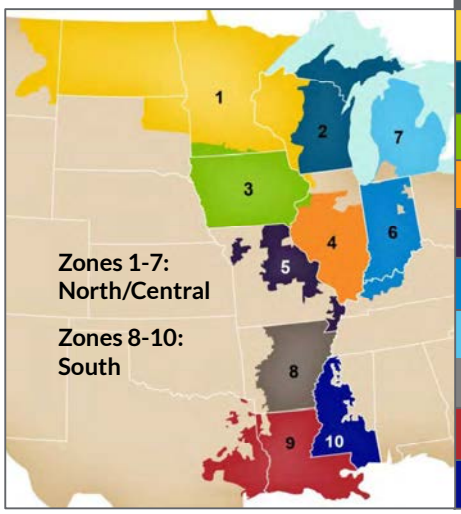
Acronyms

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

2025 PRA Results

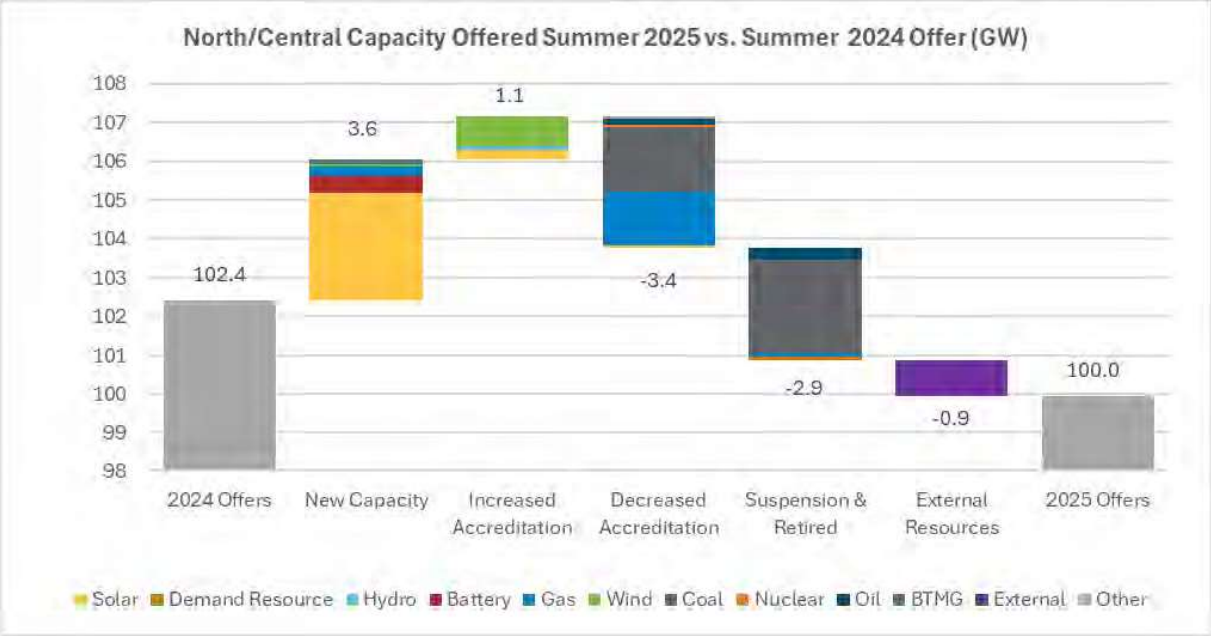
MISO Resource Adequacy Zones



	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	$666.50	$91.60	$33.20	$69.88
2				
3				
4				
5				
6				
7				
8		$74.09		
9				
10				

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

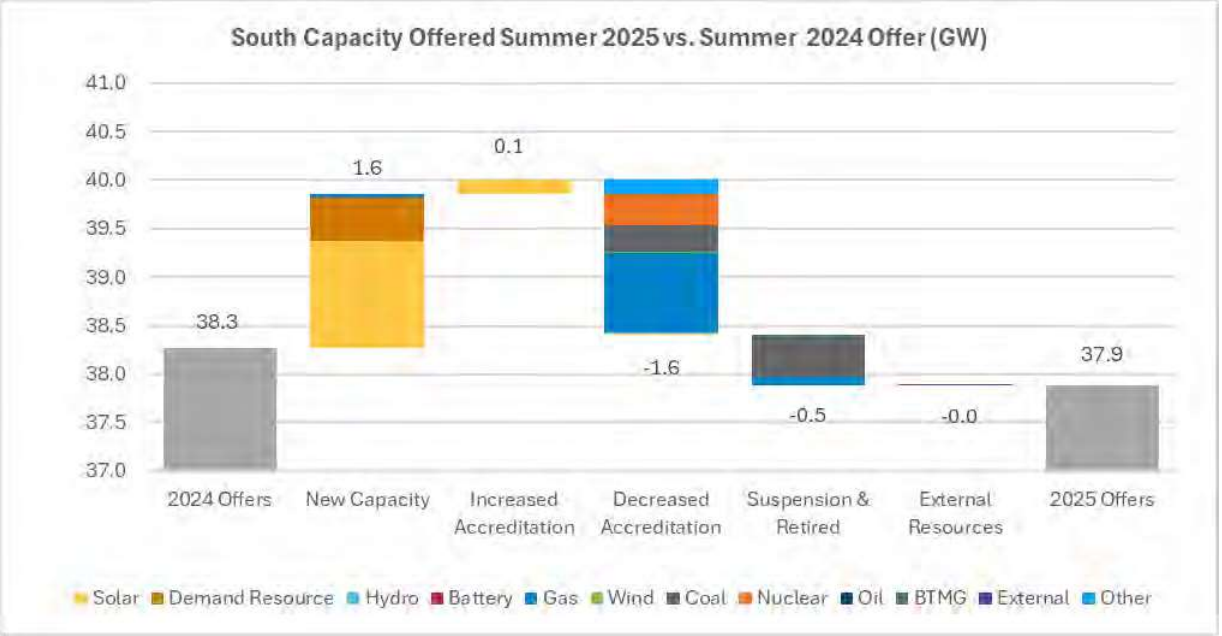
For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



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

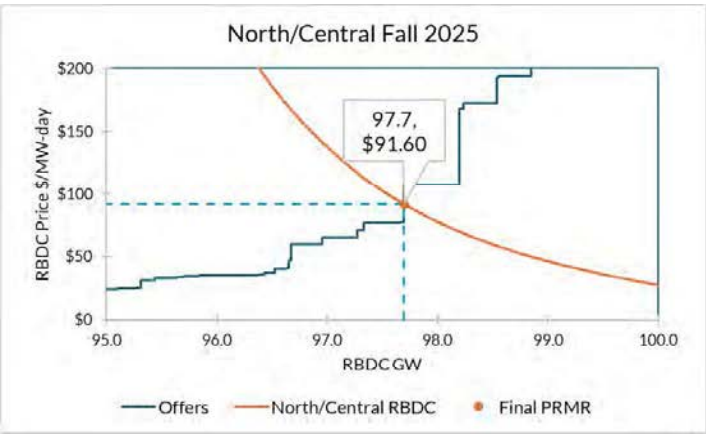
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

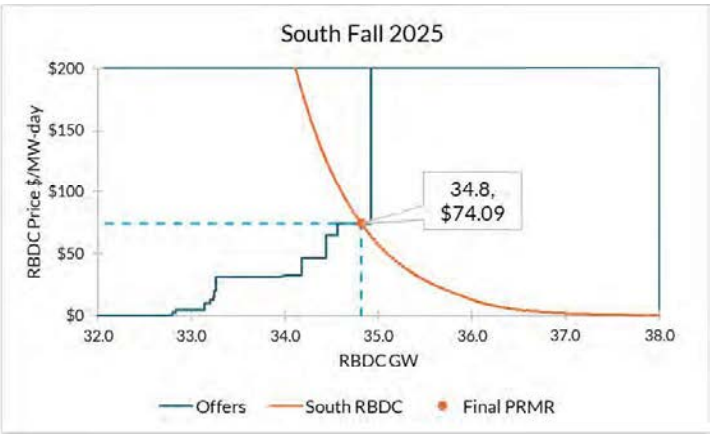
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



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

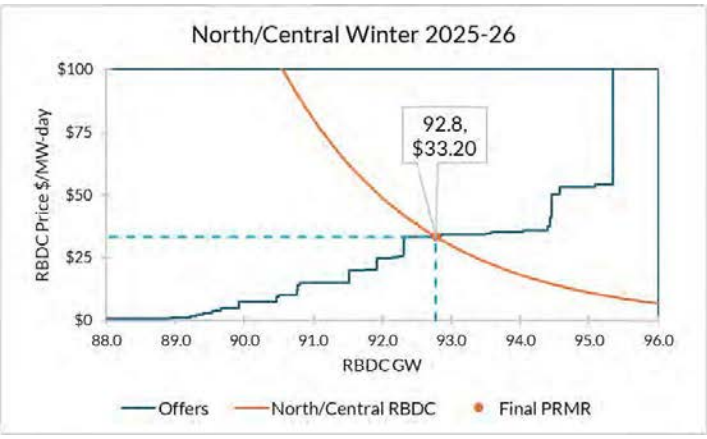
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

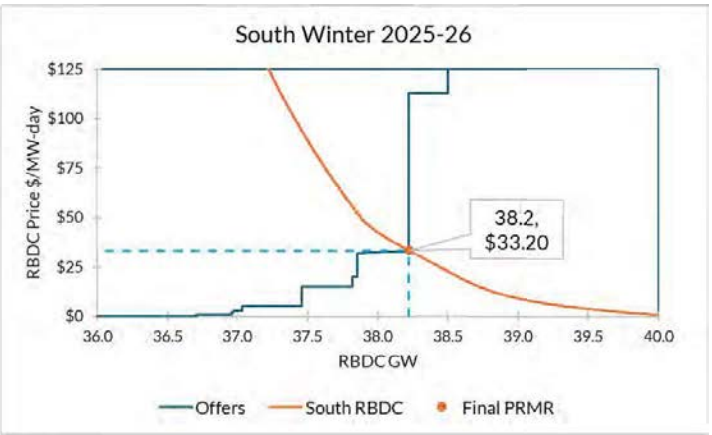




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
  - ACP for North subregion is $91.60, and $74.09 South subregion
  - A marginal 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%

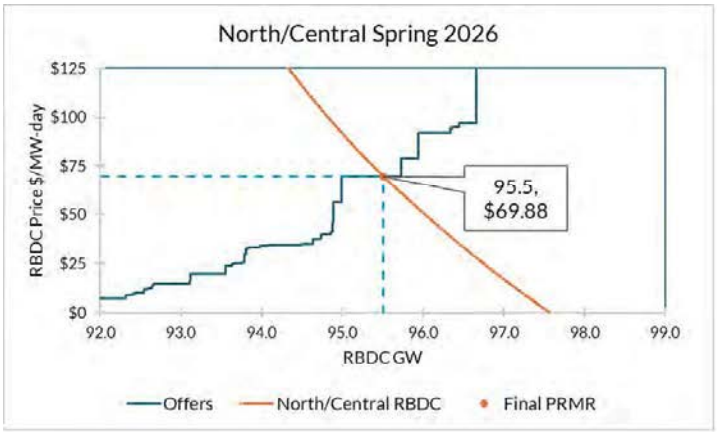
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices





- 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

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

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

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

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

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

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

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

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

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

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
Fall 2025	$91.60							$74.09			$83.24-$91.60

- 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

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

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

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

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

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

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

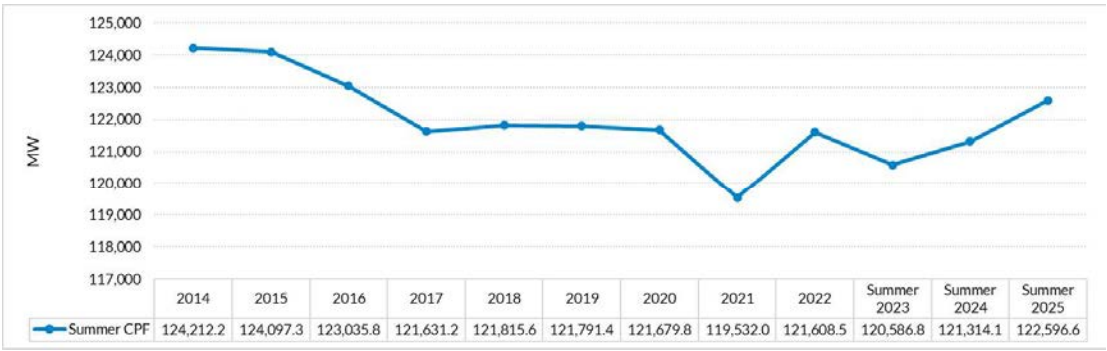
2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)

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

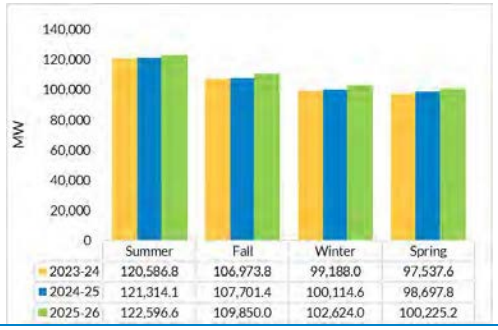
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

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

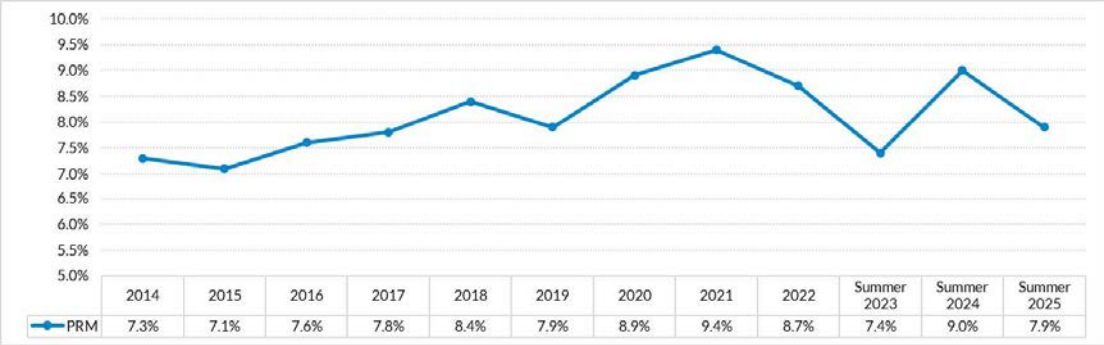


	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

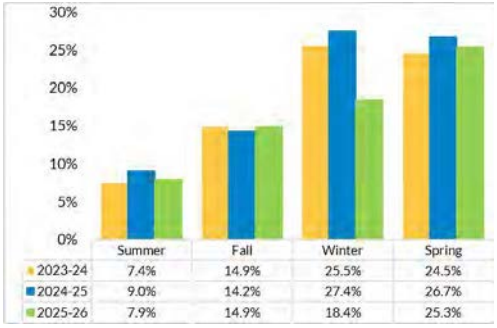
PRMR: Planning Reserve Margin Requirement

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

Planning Reserve Margin (%)

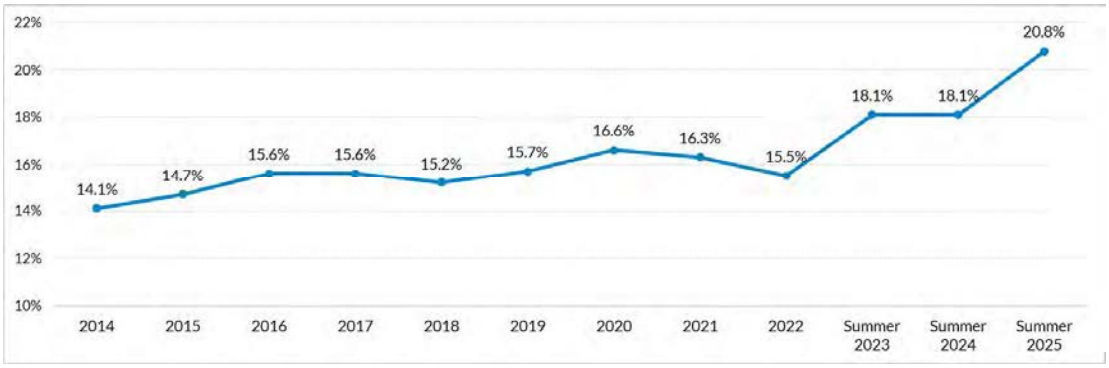


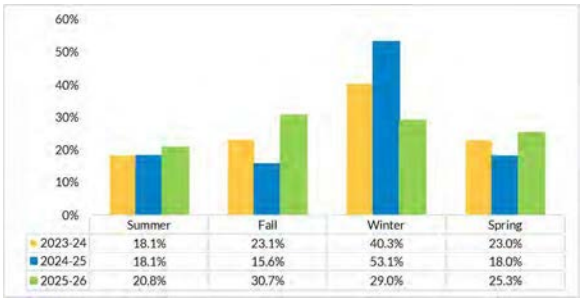
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	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 (%)





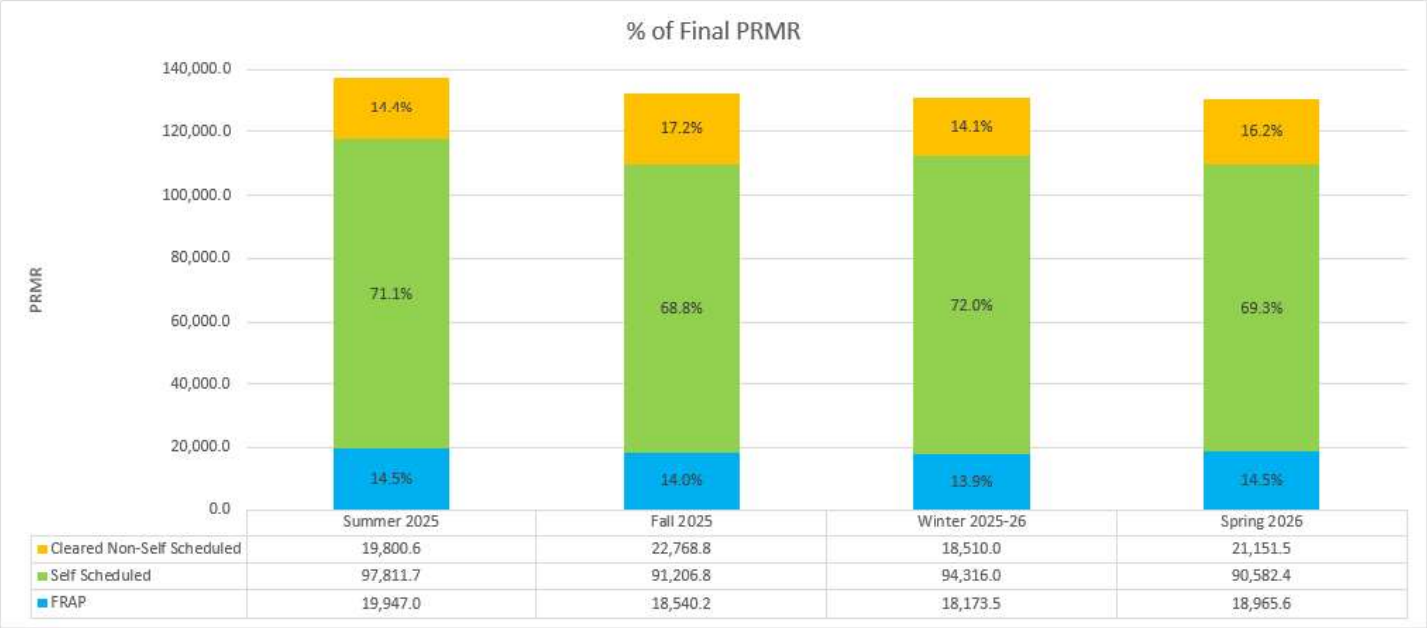
	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%
2025-26	20.8%	30.7%	29.0%	25.3%

- 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

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

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

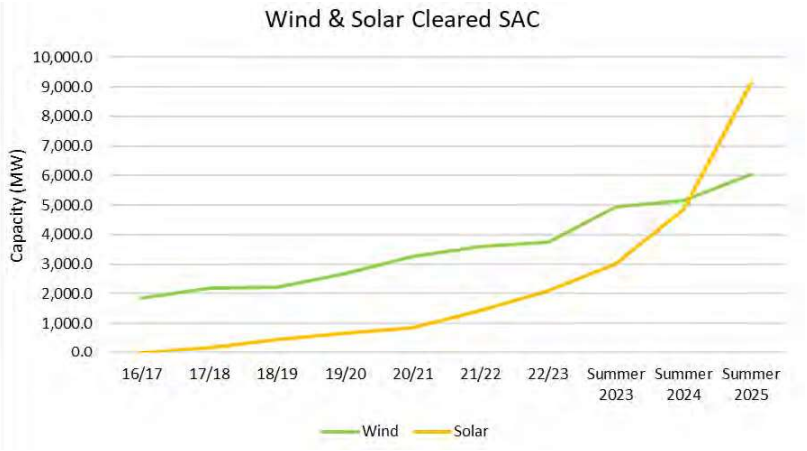


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

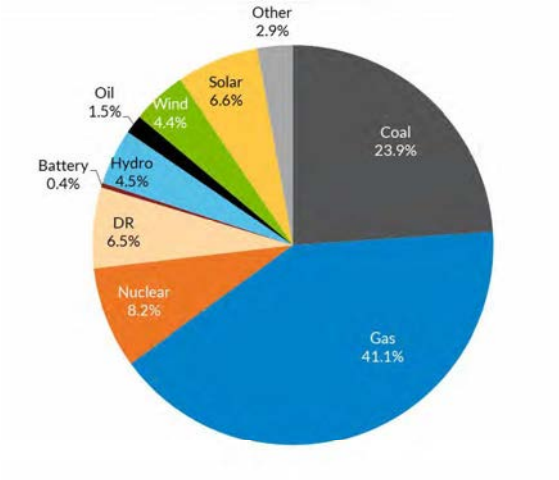
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 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

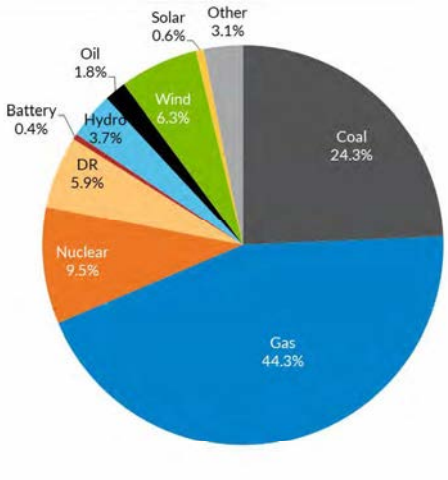
Summer 2025



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

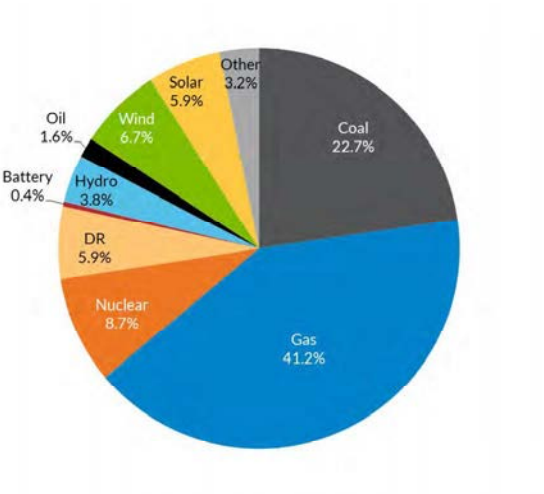


PRMR: Planning Reserve Margin Requirement

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

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

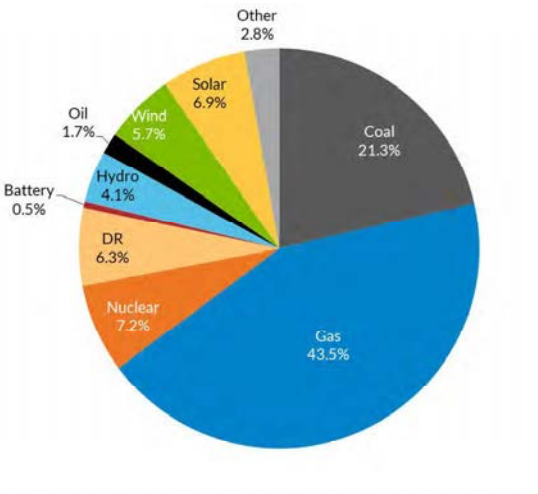
Fall 2025



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

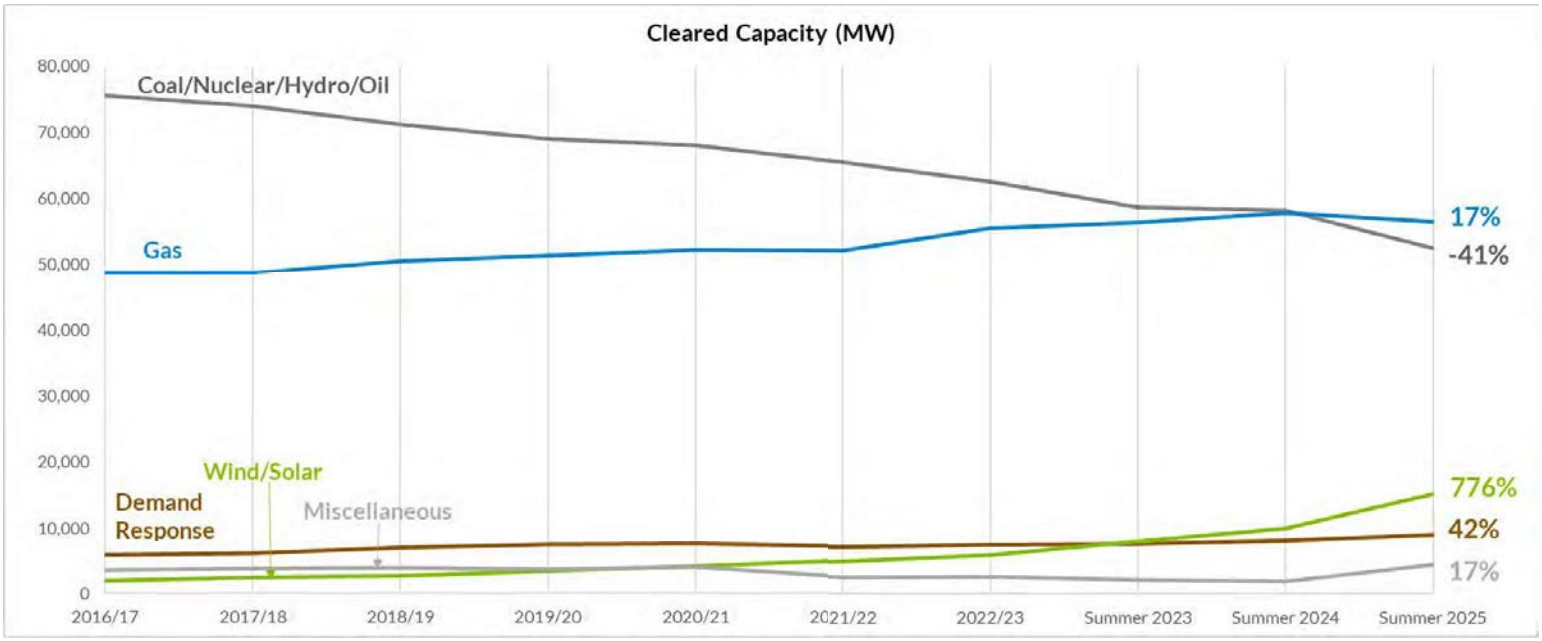
Spring 2026



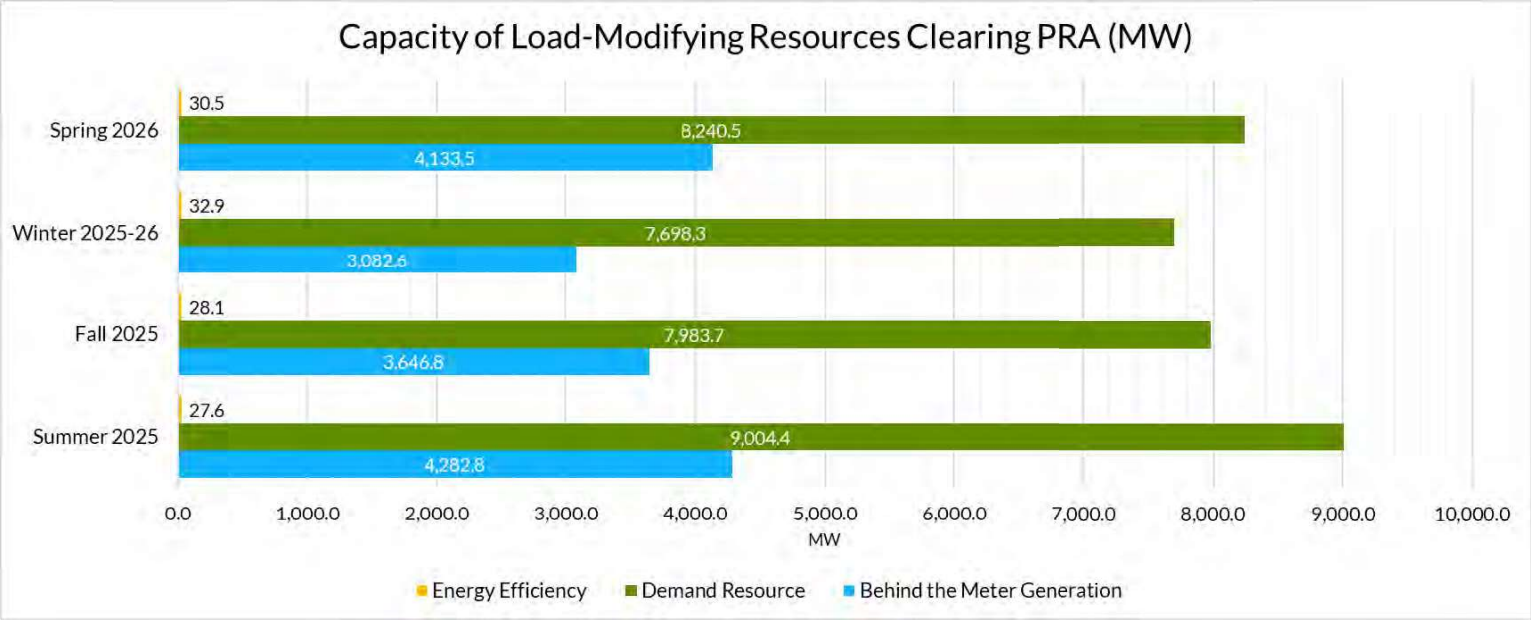
PRMR: Planning Reserve Margin Requirement

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

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/

Attachment C

Collection of MISO Attachment Y materials

Consumers Energy
Count on Us®

A CMS Energy Company

Timothy J. Sparks, P.E.
Vice President Electric Grid Integration

VIA Electronic Mail

December 14,2021

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

Re: Suspension of Campbell Units 1, 2 & 3

Dear Mr. Witmeier:

Consumers Energy Company ("Company") hereby provides notice to the Midcontinent Independent System Operator, Inc. ("MISO") that it intends to suspend Campbell Units 1, 2 and 3 effective June 1, 2025. Attached is the notice of such intent in accordance with Section 38.2.7 and Attachment Y of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

Campbell Unit 3 is jointly owned by the Company (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that, pursuant to the relevant Operating Agreements, it is authorized to submit this Attachment Y notice on behalf of all Campbell Unit 3 owners.

In the event you have any questions regarding this matter, please contact Kathy Wetzel at (517) 788-2039.

Regards,

Timothy J. Sparks
Vice President Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Cc: Kathy Wetzel
Thomas Clark

Electric Supply
Contract/Commitment Cover Sheet

(Note: Contracts, purchase orders, or other commitment instruments will not be signed unless this sheet is completed in full)

Subject/Commitment: MISO Attachment Y Notification of Generating Resources /SCU/ Pseudo-tied Out Generator Change of Status / Including Notification of Rescission Form

Reason: Notice to Suspend Karn Units 3 & 4 effective June 1, 2023.

Check One			
Yes	No*	N/A	
☐	☐	☒	1) Gateway Assessment Tool completed and attached
☒	☐	☐	2) Legal Review / Approval to Form
☐	☐	☒	3) Credit Risk Management Approval
☐	☐	☒	4) Competitive Bid
☐	☐	☒	5) Sole Source Approval completed and attached

*If No is checked or special circumstances apply, please explain:

Legal review by Emerson Hilton.

*Contract Owner: Kathy Wetzel

Department Sign Off
(Signature & Date Required)

ML Metz
Merchant Ops & PSCR

KG Troyer
EGI Contracts & Settlements
Renewables

BD Gallaway
Fuel Supply

TP Clark
Electric Supply

12/14/2021

TJ Sparks
Electric Grid Integration

Form Revised: 04/16/21

*Contract Owner Responsible for Scanning & Placing on SharePoint Site

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic copy of the completed form will be accepted by the Transmission Provider, however, a form will not be considered complete until the original form containing an original signature, including all attachments, is received by the Transmission Provider at the following address: MISO, Attention: Director of Transmission Planning; 720 City Center Drive, Carmel, IN 46032.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re: Campbell Unit 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] CAMPBELL UNITS 1+2: UMBRELLA GIA BETWEEN CONSUMERS, METC + MISO FERC DOCKET ER21-999. CAMPBELL UNIT 3: FERC DOCKET ER06-1441 FOR MISO SERVICE AGREEMENT NO. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 1st [day] of June [month] of 2025 [year]

[ ] Rescind the current notice to SuspendThe facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: TIMOTHY J SPARKS

Title: VP ELECTRIC GRID INTEGRATION

Date:

Contact Information

Email: TIMOTHY.SPARKS@CMSENERGY.COM

Phone: 517 788 1053

Andrew Witmeier
Director, Resource Utilization
317-249-5585
awitmeier@misoenergy.org

VIA OVERNIGHT DELIVERY

March 11, 2022

Timothy J. Sparks
Vice President, Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Subject: **Approval of Campbell Units 1,2 &3 Attachment Y Suspension Notice**

Dear Mr. Sparks,

On December 14, 2021, Consumers Energy Company submitted an Attachment Y Notice to MISO for the suspension of Campbell Units 1,2 & 3, effective June 1, 2025. After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the suspension of Campbell Units 1,2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,2 & 3 may suspend without the need for the generators to be designated as a System Support Resource ("SSR") units as defined in the Tariff.

As there were no reliability criteria violations, MISO will continue to preserve the confidentiality of the Attachment Y Notice.

Please do not hesitate to contact me if you have any questions regarding this matter.

Respectfully,

Andrew Witmeier
Director, Resource Utilization

VIA EMAIL

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

May 28, 2025

Re: Modified Suspension Date for Campbell Units 1, 2, & 3

Mr. Witmeier:

On December 14, 2021, Consumers Energy Company ("Consumers Energy") submitted an Attachment Y Notice to the Midcontinent Independent System Operating, Inc. ("MISO") for the suspension of Units 1, 2, and 3 at the J.H. Campbell Generation Complex ("Campbell Plant"), effective June 1, 2025. After reviewing for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), MISO determined the suspension of Campbell Plant Units 1, 2, and 3, would not result in violations of applicable reliability criteria, as outlined in the Tariff. On March 11, 2022, MISO approved the suspension of Campbell Plant Units 1, 2, and 3 without the need for the generators to be designated as System Support Resource units as defined in the Tariff.

On May 23, 2025, the U.S. Department of Energy ("DOE") issued Order No. 202-25-3 (the "Order"), requiring the Campbell Plant to be available to MISO through August 20, 2025.

In order to comply with the Order, Consumers Energy hereby provides notice to MISO, consistent with Section 38.2.7(d)(ii)(1) of the Tariff, of its intent to modify the current Attachment Y Notice such that the Campbell Plant will now suspend on August 21, 2025.

As noted in Consumers Energy's original Attachment Y Notice, Campbell Unit 3 is jointly owned by Consumers Energy (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that it has notified all Campbell Unit 3 owners of this submittal.

In the event you have any questions regarding this matter, please contact Derek Anspaugh at (517) 788-1869.

Regards,

Sri Maddipati
VP Electric Supply
1945 W. Parnell Rd
Jackson, MI 49901

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic form must be submitted to the Transmission Provider via its online application tool in the manner specified by the Transmission Planning Business Practices Manual (BPM-020), and a form will be considered complete on the date of such online application.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re Campbell 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement]
Campbell Units 1 & 2: Umbrella GIA Between Consumers, METC, and MISO, FERC Docket No. ER24-1359
Campbell Unit 3: FERC Docket No. ER06-1441 for MISO Service Agreement No. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 21 [day] of August [month] of 2025 [year]

[ ] Rescind the current notice to Suspend

The facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: Srikanth Maddipati

Title: VP Electric Supply

Date: May 28, 2025

Contact Information

Email: sri.maddipati@cmsenergy.com

Phone: 517-788-0635

From:	Marc Keyser
To:	Rachael H. Moore; Huaitao Zhang; DEREK S. ANSPAUGH; Adam C. French; NICHOLAS B. TENNEY; Emerson J. Hilton
Cc:	Sumit Pal Brar
Subject:	RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required
Date:	Friday, May 30, 2025 4:05:01 PM

##CAUTION##: This email originated from outside of CMS/CE. Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Rachael: I'm responding back on behalf of the team, after they briefly reviewed with legal here:

we received the Attachment Y, and the new cessation is 8/21/2025. Additionally, you have until 8/21/2027 to submit a new replacement request before the suspension period ends. In other words, the Attachment Y remains as is, still approved, except with a new/different start date.

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Friday, May 30, 2025 12:15 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

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Thank you, Huaitao. Can you confirm that this modification of the suspension start date provided consistent with Section 38.2.7(d)(ii)(1) of the Tariff does not impact the overall approval of the Attachment Y the Company previously received on March 11, 2022, and that the Company is still approved to enter suspension (now effective 8/21/25)?

Thank you!

Rachael Moore | Senior Attorney
[redacted]

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Wednesday, May 28, 2025 1:47 PM

To: Rachael H. Moore <Rachael.Moore@cmsenergy.com>; DEREK S. ANSPAUGH <DEREK.ANSPAUGH@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

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Rachael,

Thanks for the quick response, and we are all good.

Thanks,
Huaitao

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Wednesday, May 28, 2025 12:40 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

> **Warning!** This email originated from outside the organization and caution should be used when clicking on links/attachments. If you suspect this email is malicious, use the 'Phish Alert' button.

Huaitao –

Attached is the modified Attachment Y with the amended suspension start date of 8/21/2025. Please let me know if we should send this notice of Modified Attachment Y to anyone else at MISO or if you would like us to mail a physical copy as well.

Thank you,
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Rachael H. Moore
Sent: Tuesday, May 27, 2025 11:52 AM
To: Adam C. French <adam.french@cmsenergy.com>; Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <nicholas.tenney@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Good afternoon,

Yes, I will be working with members of the Company to ensure we have the Attachment Y notice updated by 5/28. Please let me know if there is a specific contact at MISO we should plan to send this to.

Thank you!
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Adam C. French <ADAM.FRENCH@cmsenergy.com>
Sent: Tuesday, May 27, 2025 11:49 AM
To: Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

It is my understanding that is being handled by Rachael Moore
RACHAEL.MOORE@CMSENERGY.COM

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Tuesday, May 27, 2025 11:41 AM
To: NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: FW: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

You don't often get email from hzhang@misoenergy.org. Learn why this is important [aka.ms]

##CAUTION##: This email originated from outside of CMS/CE. Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Nick and Adam,

Marc pointed to me that you are the contact for this request.

Thanks,
Huaitao

From: Huaitao Zhang
Sent: Tuesday, May 27, 2025 11:05 AM
To: KATHY S. WETZEL <KATHY.WETZEL@cmsenergy.com>
Cc: timothy.sparks@cmsenergy.com; Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>; Jagdesh Shivani <JShivani@misoenergy.org>
Subject: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Hi Kathy,

Pertain to the Order from Secretary of Energy regarding the suspension/cessation date of Campbell units 1,2&3, MISO requests Consumer Energy to submit the following application updates to MISO by 5/28/2025:

Attachment Y request with suspension start date as 8/21/2025

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

Thanks,
Huaitao Zhang
Resource Utilization Engineer

Integrity | Collaboration | Commitment | Creativity | Adaptability

Attachment D

Consumers' Responses from June 10, 2025

Question:

23. Absent continued operation of the Campbell Plant, what was Consumers Energy's Zone Resource Credit (ZRC) position for planning year 2025-2026.

Response:

The table below shows our capacity positions using the initial Planning Reserve Margin Requirement (PRMR) for each season of planning year 2025. These numbers do not include any contributions from the Campbell coal-fired generating units.

PY2025	**ZRC**
Summer	272.9
Fall	842.7
Winter	0.0
Spring	4.3

Date: June 10, 2025

Question:

24. How many ZRCs does Consumers anticipate will be accredited for the continued operation of the Campbell Plant?

Response:

At this time we do not anticipate the Campbell units contributing any Zonal Resource Credits to our capacity positions throughout planning year 2025.

Date: June 10, 2025

Attachment Q

Petition for Review - COA DC SOM v USDOE
(DOE Order No. 202-25-3)

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

THE PEOPLE OF THE STATE OF MICHIGAN, *Petitioner*, v. UNITED STATES DEPARTMENT OF ENERGY, and CHRIS WRIGHT, Secretary, UNITED STATES DEPARTMENT OF ENERGY *Respondents*.	)	DOE Order No. 202-25-3

PETITION FOR REVIEW

Pursuant to Rule 15 of the Federal Rules of Appellate Procedure, Circuit Rule 15, and section 313(b) of the Federal Power Act, 16 U.S.C. § 825*l*(b), Michigan Attorney General Dana Nessel, on behalf of the People of the State of Michigan, hereby petitions the Court for review of the Order No. 202-25-3 of Respondents, Chris Wright, Secretary, United States Department of Energy, and the United States Department of Energy, issued on May 23, 2025 (the "Campbell Order," attached as Exhibit A). The Department of Energy issued the Campbell Order pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), a provision initially vested in the Federal Power Commission that was assigned to the Department through the Department of Energy Organization Act, 42 U.S.C. § 7151(b). As an order issued under the Federal Power Act, the Campbell Order is subject to the

rehearing and judicial review provisions of 16 U.S.C. § 825*l*. *See* 42 U.S.C. § 7192(a) ("Judicial review of agency action taken under any law the functions of which are vested by law in, or transferred or delegated to the Secretary [of Energy] . . . shall, notwithstanding such vesting, transfer, or delegation, be made in the manner specified in or for such law.").

On behalf of the People of the State of Michigan, the Michigan Attorney General participated in the proceedings before the Department of Energy and timely filed a request for rehearing of the Campbell Order. That rehearing request may be deemed denied by operation of law because the Department did not act upon it within 30 days. *See* 16 U.S.C. § 825*l*(a); Allegheny Def. Project v. FERC, 964 F.3d 1, 18-19 (D.C. Cir. 2020). Therefore, the Michigan Attorney General may file this petition for review under 16 U.S.C. § 825*l*(b). This Court has jurisdiction, and venue in this Court is proper, under 16 U.S.C. § 825*l*(b). The Michigan Attorney General respectfully requests that this Court hold unlawful, vacate, and set aside the Campbell Order, and grant such further relief as may be deemed just and proper.

Dated: July 24, 2025

Respectfully submitted,

Dana Nessel,
Michigan Attorney General

/s/ Michael Moody
Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

CC:
DOE:
AskCR@hq.doe.gov
The.secretary@hq.doe.gov

CECo:
Bret.totoraitis@cmsenergy.com
Kelly.hall@cmsenergy.com

Earthjustice:
mlenoff@earthjustice.org
sfisk@earthjustice.org
msoules@earthjustice.org
lpiette@earthjustice.org
sdoshi@earthjustice.org
cpowell@earthjustice.org
atom@earthjustice.org
astatler@earthjustice.org

MEC:
charlotte@environmentalcouncil.org

Sierra Club:
greg.wannier@sierraclub.org
sanjay.narayan@sierraclub.org
elena.saxonhouse@sierraclub.org

NRDC:
creiser@nrdc.org
gmccabe@nrdc.org

ELPC:
bklein@elpc.org

Clean Air Task Force:
dfidler@catf.us
fsturges@catf.us

Public Citizen, Inc.:
tslocum@citizen.org

Ecology Center:
alexis@ecocenter.org

Union of Concerned Scientists:
jgignac@ucs.org

UCC:
sergio@uccgr.org

Environmental Defense Fund:
tekelly@edf.org
tcarbonell@edf.org

Vote Solar:
will@votesolar.org

Midcontinent Independent:
tcaister@misoenergy.org
mkessler@misoenergy.org
jholsclaw@calfee.com
tcarpenter@calfee.com

Michigan Public Power:
arobbins@washingtonenergylaw.com
droby@washingtonenergylaw.com
tsteiger@washingtonenergylaw.com

Maryland Office of People:
William.fields@maryland.gov
Philip.sussler@maryland.gov
Alexis.lewis@maryland.gov

MISO States:
brad@misostates.org
tricia@misostates.org

Order No. 202-25-3

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 for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States 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

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[1] In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.[2]

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[3] Additionally EIA stated, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[4] The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to "speed closure" of Campbell in 2025, several years before the end of its scheduled design life.[5] Although MISO and Consumers have

[1] 2025 summer reliability assessment. (May 14, 2025). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf
[2] *Id*.
[3] U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: https://www.eia.gov/state/print.php?sid=mi.
[4] *Id.*
[5] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."

MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and the results "reinforce the need to increase capacity."[6]

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) 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.

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

A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

[6] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant 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.

D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also 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 of Energy from time to time.

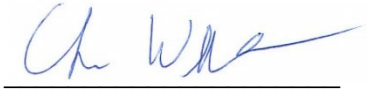
E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.

I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Order No. 202-25-3

REQUEST FOR REHEARING BY MICHIGAN ATTORNEY GENERAL DANA NESSEL

Dana Nessel
Michigan Attorney General

Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

Dated: June 18, 2025

Pursuant to section 313*l* of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Michigan Attorney General Dana Nessel, on behalf of the people of the State of Michigan, requests that the Department of Energy (Department or DOE) grant rehearing of Order No. 202-25-3 (May 23, 2025) ("Order"). The Order invoked the Department's emergency authority under section 202(c) of the Act to prevent the scheduled retirement of the J.H. Campbell power plant (J.H. Campbell) in West Olive, Michigan.

The Order is an unlawful abuse of the Department's emergency authority. Until now, the Department has reserved section 202(c) for real emergencies like natural disasters and extreme weather and has typically acted at the behest of grid operators or governmental bodies. In the Order, acting on its own motion and without notice, the Department declares that the retirement of J.H. Campbell presents an emergency. But the Order's emergency determination cannot bear even the mildest scrutiny.

The scheduled retirement of J.H. Campbell was the culmination of a carefully planned process that unfolded over four years. Under the oversight of the Michigan Public Service Commission (MPSC), Consumers Energy (Consumers) executed a plan to retire an old and inefficient facility, J.H. Campbell, and replace it largely with newer resources that would both increase Consumers' available generation capacity and save its ratepayers money. J.H. Campbell's proposed retirement was also studied carefully by the Midcontinent Independent System Operator (MISO), the regional

grid operator, which determined that the facility could retire without causing reliability issues.

In the Order, the Department uses its authority under section 202(c) in a manner untethered from the need to identify a real emergency and unhindered by the statutory requirement that the actions it orders go no further than necessary to address the emergency. The result of this overreach will be unnecessary costs imposed on already-overburdened ratepayers, needless pollution emitted into Michigan and its neighboring states, and an unprecedented intrusion into the authority of states and the Federal Energy Regulatory Commission to regulate the resource adequacy of our electric grid.

I. MOTION TO INTERVENE

The Michigan Attorney General,[1] on behalf of the people of the State of Michigan, moves to intervene in this proceeding and thereby to become a party for purposes of Section 313*l* of the Act, 16 U.S.C. § 825*l*. The People of the State of Michigan have an interest in and are aggrieved by the Order in several ways. First, households and businesses in Michigan will pay higher electricity bills as a result of the Order. The retirement of J.H. Campbell and its replacement with more cost-effective resources were elements of a careful plan expected to save Michigan

[1] *See* MCL 14.28 ("The attorney general . . . may, when in [her] own judgment the interests of the state require it, intervene in and appear for the people of this state in any other court or tribunal, in any cause or matter, civil or criminal, in which the people of this state may be a party or interested."). *See also In re Certified Question*, 465 Mich 537, 543-545; 638 NW2d 409 (2002), *Gremore v Peoples Community Hospital Authority*, 8 Mich App 56; 153 NW2d 377 (1967), and *People v O'Hara*, 278 Mich 281; 270 NW2d 298 (1936).

ratepayers nearly $600 million.[2] By ordering the continued operation of J.H. Campbell, the Order ensures that Michigan ratepayers will pay higher costs. Although the precise amounts of costs are not yet known, it is certain that Michigan ratepayers will be stuck with substantial new costs in excess of what they would have paid absent the Order.

Second, the People of the State of Michigan will suffer environmental harms as a result of the Order. J.H. Campbell is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[3] among other pollutants. By prolonging the operations of J.H. Campbell beyond its planned retirement date, the Order will increase the amount of pollution emitted in the state of Michigan, causing harms to the public health and welfare.

Third, the retirement of J.H. Campbell on May 31, 2025, was a provision agreed to as part of a settlement agreement in Michigan Public Service Commission Case (MPSC) No. U-21090, to which the Michigan Attorney General was a party. Because the Order deprives the Michigan Attorney General of the benefit of her bargain under the settlement agreement, the Michigan Attorney General will suffer a discrete and separate harm as a result of the Order.

II. BACKGROUND

A. DOE's Historical Use of Section 202(c).

[2] *See* Michigan Public Service Commission Case No. U-21090-0867, Reply Brief of Consumers at 1 – 2, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000032ZSXAA2.
[3] *See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).

In the past, the Department has used section 202(c) sparingly. The Department has used this authority only in response to concrete, particularized emergencies, and subject to limitations to ensure that the Department's reach extends no further than necessary to address the emergency at hand.

Between enactment of the Department of Energy Organization Act in 1977, Pub. L. No. 95-91, and the end of last year, the Department appears to have used section 202(c) nineteen times, not counting amendments and extension orders. DOE's first usage of section 202(c) came in response to the California Energy Crisis in 2000.[4] That order was followed by two others directing the operation of the Cross-Sound Cable, a submarine transmission line connecting New York and Connecticut that was complete but that had been delayed from entering service due to environmental permitting issues.[5] But by far the most common usage – comprising 13 of 19 instances – has been in response to extreme weather events such as hurricanes,[6] extreme cold,[7] and extreme heat.[8] In each of these weather-driven cases, the exercise of emergency power was requested by the relevant system operator or responsible utility, or both.

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[4] DOE, *Order Pursuant to Section 202(c) of the Federal Power Act* (Dec. 14, 2000). Section 202(c) was used by the Federal Power Commission prior to the Department of Energy Organization Act's creation of DOE. Those uses were generally limited to orders directing interconnection as a result of discrete and sudden emergencies or war. *See* Benjamin Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. 789, 822 (2025).

[5] *See* DOE Order No. 202-02-1 (Aug. 16, 2002); DOE Order No. 202-03-01 (Aug. 14, 2003).

[6] *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (response to Hurricane Rita); DOE Order No. 202-08-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton).

[7] *See* DOE Order No. 202-21-1 (Feb. 14, 2021); DOE Order No. 202-22-3 (Dec. 23, 2022); DOE Order No. 202-22-4 (Dec. 24, 2022).

[8] *See* DOE Order No. 202-20-2 (Sept. 6, 2020) (responding to extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 202-22-1 & 2 and amendments (same).

And in each, DOE carefully limited its remedy to ensure that generation facilities were only ordered to run in circumstances necessary to address the emergency and in a manner so as to minimize any conflict with environmental requirements.[9] DOE also limited the duration of those orders to the minimum period necessary to address the emergency, often shorter than 10 days.[10]

Prior to the Order, DOE had used section 202(c) on three occasions to delay the retirement of generation facilities.[11] These cases had key features in common. In each: (i) the order was requested by a system operator or governmental body; (ii) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (iii) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and, (iv) DOE tailored its order to go no further than necessary to address the emergency.

The first such instance came in 2004, when the District of Columbia's Public Service Commission requested an order directing the continued operation of a power plant located in Alexandria, Virginia, owned by the Mirant Corporation (Mirant). After its state regulator found the plant to be out of compliance with its air permit, Mirant abruptly announced that the plant would close.[12] The D.C. Public Service Commission, supported by the local utility, PEPCO, explained that the Mirant facility

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[9] *See supra* notes 3 – 5.
[10] *Id*.
[11] Nor did the DOE's predecessor agency, the Federal Power Commission, use section 202(c) to delay retirement of any generation units between the section's enactment in 1935 and the formation of DOE in 1977. *See* Rolsma, 57 U. Conn. L. Rev. at 843-46.
[12] DOE Order No. 202-05-3 (Dec. 20, 2005) at 1 (explaining that Mirant provided emissions information to its state regulator on August 19, 2005, the regulator demanded immediate action that same day, and Mirant decided to cease operations on August 24).

directly powered downtown D.C. and that, without it, critical federal infrastructure faced an unacceptable risk of blackout.[13] Before acting on the request, the Department commissioned an analysis from the Oak Ridge National Laboratory that confirmed the threat that the plant's closure would pose to reliability in D.C.[14] Based on that study, and based on the severity of the harm that could result from a prolonged power outage to downtown D.C., the Department issued an order directing the continued operation of the Mirant facility.[15] The Department took pains, however, to limit its order to go no further than necessary to address the emergency. The Department directed Mirant to maintain the facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[16]

Twelve years later, in 2017, the Department received a request from the Grand River Dam Authority (GRDA), an Oklahoma state agency, to direct the continued operation of Unit No. 1 at the Grand River Energy Center. GRDA explained that the Grand River Energy Center was needed to provide dynamic reactive power support to the local grid, a fact confirmed by the region's Reliability Coordinator, the Southwest Power Pool (SPP). GRDA explained, however, that it would be unable to provide reactive power without action from DOE. Unit No.1, the subject of the request, had been ordered to close by an Administrative Order of the Environmental Protection Agency. Unit No. 2 had been struck by lightning and was under repair.

[13] *Id*. at 2.
[14] *Id*. at 3 – 4.
[15] *Id*. at 5 – 8.
[16] *Id*. at 10 – 11.

And, construction of the new Unit No. 3 had been delayed because flooding in Louisiana interfered with the fabrication of essential project materials.[17] The Department granted GRDA's request, ordering Unit No. 1 to remain in operation for 90 days or until Unit No. 2 or Unit No. 3 were brought online, whichever came first.[18] The Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[19]

Later that year, the Department received a pair of requests from PJM and Dominion Virginia (Dominion) to direct the continued operation of Units 1 and 2 of the Yorktown Power Station. PJM and Dominion explained that, based on PJM load flow studies, these units were necessary to prevent uncontrolled power disruptions and shedding of critical loads in the North Hampton Roads area east of Richmond.[20] DOE issued an order directing Dominion to maintain operation at the two units, but to dispatch those units "only when called upon by PJM for reliability purposes."[21] DOE later extended the order several times due to the delayed completion of the transmission line needed to resolve the reliability issue. In doing so, DOE cited the "imminent" risk of load-shedding in the North Hampton Roads area absent extension of the order.[22] In its extension order, the Department continued to limit dispatch of

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[17] Letter Request of Grand River Dam Authority, April 11, 2017. Available at https://www.energy.gov/sites/default/files/2017/05/f34/GRDA%20public%20202%28c%29%20letter.pdf.
[18] DOE Order No. 202-17-1 at 2.
[19] *Id*.
[20] DOE Order No. 202-17-2, at 1.
[21] *Id*. at 2.
[22] DOE Order No. 202-17-4, Summary of Findings, Sept. 14, 2017.

the units only when called upon by PJM for reliability purposes and, further, directed PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating the units.[23]

B. Executive Order 14262 and the White House Strategy to Prop Up the Coal Industry.

Over the past several months, the White House and the Department have sought to radically transform how section 202(c) of the Federal Power Act is applied, departing in almost every material respect from the longstanding approach described above. As shown below, the Order cannot be understood intelligibly as a response to a discrete event or emergency akin to past orders under section 202(c). Rather, it can only be understood as part of a long-term and multi-part strategy to preserve coal and other fossil fuel generation under the guise of grid reliability concerns.

On April 8, 2025, President Trump issued Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*.[24] The Executive Order was issued concurrently with three other executive actions aimed at supporting the coal industry that were announced at a White House political event explicitly focused on that objective.[25] This event, and the related Executive Order, are one of several in a series of public actions by the Administration aimed at reversing coal plant retirements and promoting fossil fuel generation.

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[23] DOE Order No. 202-17-4 at 2.
[24] Executive Order 14262, 90 Fed. Reg. 15521 (April 14, 2025).
[25] New York Times, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry* (April 8, 2025); Executive Order 14261, *Reinvigorating Americans Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15517 (April 14, 2025); Executive Order 14260, *Protecting American Energy from State Overreach*, 90 Fed. Reg. 15513 (April 14, 2025); *Regulatory Relief for Certain Stationary Sources To Promote American Energy*, 90 Fed. Reg. 16777 (April 21, 2025).

Executive Order 14262 directs DOE to, among other things, streamline and expedite the issuance of emergency orders under section 202(c), specifically in order to "safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply [that] is necessary to prevent a complete grid failure."[26] It also directs DOE to take a subsequent series of actions related to national resource adequacy, including mandating:

- the development of a uniform methodology for assessing reserve margins and identifying "at-risk" regions;
- establishment of a process by which the developed methodology and any analysis results are regularly assessed; and,
- establishment of a protocol to identify generation resources within a region that are critical to system reliability, a mechanism under section 202(c) to ensure such generation resources are appropriately retained and, for resources over 50MW, are prevented from leaving the bulk-power system or converting their source of fuel.[27]

DOE has not yet published the analysis or protocols—the deadline provided in Executive Order 14262 is July 7.

Executive Order 14262 states that it is intended to help address the national energy emergency declared in the earlier-issued Executive Order 14,156, *Declaring a National Energy Emergency*.[28] In fact, this order is part of a broader pattern in which the Administration has expansively invoked emergency powers to achieve long-standing political objectives, rather than respond to genuine, unforeseen crises. The

[26] Executive Order 14262 section 3(a).
[27] Executive Order 14262 section 3(b), (c).
[28] Executive Order 14262, section 2.

President has declared eight national emergencies in 2025 alone—more than any other President in the first 100 days of an administration.[29]

C. The Planned Retirement of JH Campbell.

i. Description of J.H. Campbell

J.H. Campbell is a three-unit coal-fired power plant with a total rated net generating capability of approximately 1,450 megawatts (MW).[30] (The Order incorrectly states that J.H. Campbell has a capacity of 1,560 MW). In its current degraded condition, however, J.H. Campbell has a maximum capacity of 920 MW.[31] Part of that difference comes from the fact that Unit 2 is not operational, nor was it operational when the Order was issued. When Unit 2 comes back on-line later this month, the maximum capacity of the facility will be 1,180 MW. J.H. Campbell Unit 1 is 63-years-old and has a rated net generating capability of 261 MW, but now has an effective maximum output of 220 MW.[32] Unit 2 is 58-years-old and has a rated net generating capability of 356 MW. Currently out of service, when Unit 2 comes back online it will have a maximum capacity of 260 MW.[33] Unit 3 is 45 years old and has a rated net generating capability of 843 MW. The current maximum capacity of Unit 3 is 700 MW.[34] Consumers operates the entire J.H. Campbell plant and is the sole

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[29] *See* https://www.brennancenter.org/our-work/research-reports/declared-national-emergencies-under-national-emergencies-act.

[30] Michigan Public Service Commission (MPSC) Case No. U-21585, Direct Testimony of Richard Blumenstock, p. 7, Table 1 (5 Tr 1394-95); see also, https://www.consumersenergy.com/about-us/electric-generation/campbell-complex-retirement, last checked June 11, 2025 (reporting 1,450 MW of capacity).

[31] Conversation between representatives of Consumers and the undersigned counsel, June 12, 2025.

[32] *Id.*

[33] *Id.*

[34] *Id.*

owner of Units 1 and 2. Consumers owns about 93% of Unit 3, the Michigan Public Power Agency owns 4.8% of Unit 3, and Wolverine Power Supply Cooperative owns less than 2% of Unit 3.[35]

J.H. Campbell and Consumers' service territory are located within MISO Local Resource Zone 7. Most of the lower peninsula of Michigan is in MISO Zone 7, except for a small area in the southwest portion of the State, which is in PJM.

ii. State proceeding approving the retirement of J.H. Campbell

In 2021, Consumers proposed to retire J.H. Campbell in 2025 for economic reasons. The MPSC thoroughly reviewed the proposed retirement for a year in an integrated resource plan (IRP) proceeding governed by Michigan statute.[36] No party in the case opposed the retirement of Units 1 and 2; and only a few opposed the retirement of Unit 3.[37] The MPSC ultimately approved Consumers' proposed retirement of J.H. Campbell in a settlement joined by most of the parties to the case. A single party appealed the MPSC's decision to approve the retirement of Unit 3, but the Michigan Court of Appeals affirmed that decision in 2023.[38] Both the MPSC and the appeals court found that Michigan would still have more than enough generating capacity to serve demand after J.H. Campbell retired.[39]

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[35] MPSC Case No. U-21090 (Kapala Direct, 7 Tr 1739); Ex. WPSC-1, p. 19 (Agreement, p. 11), section 2.1, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001QqldAAC.

[36] MCL 460.6t.

[37] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 8.

[38] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[39] *Id.*

Michigan's IRP statute requires electric utilities whose rates are regulated by the MPSC to periodically file an integrated resource plan. The IRP is a projection of the utility's load obligations and a plan to meet those obligations.[40] The IRP statute directs the MPSC to approve a plan if the MPSC determines that it "represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."[41] To make that decision, the statute instructs the MPSC to consider whether the IRP appropriately balances seven statutory factors: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective.[42]

The IRP statute also directs the MPSC to establish – among other things – computer modeling scenarios that must be used to analyze the costs of possible plans in an IRP, including costs associated with plant retirement dates.[43] In the modeling used to prepare its 2021 IRP, Consumers determined that it would be most cost-effective to retire the entire J.H. Campbell plant in 2025.[44] Later in the proceeding, Consumers conducted more modeling that compared other possible retirement dates

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[40] MCL 460.6t(3).

[41] MCL 460.6t(8)(a).

[42] *Id.*

[43] MCL 460.6t(1).

[44] MPSC Case No. U-21090 (Blumenstock Direct, 3 Tr 99 and 147-49), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001OEXnAAO.

to a 2025 retirement and again concluded that the most cost-effective retirement date was 2025.[45] Among other things, parties to the IRP case noted that the 2025 retirement of J.H. Campbell would save ratepayers $150 million in avoidable capital expenditures.[46]

After months of litigation, most of the parties reached a settlement agreement, which Consumers filed with the MPSC on April 20, 2022.[47] The settlement agreement approved the retirement of J.H. Campbell – but it also approved the construction, procurement, and extension of other major generating resources. The net effect of these changes was to substantially increase the total generating resources available to MISO Zone 7.

iii. Effect of Consumers' overall plan on resource adequacy

MISO measures capacity for resource adequacy purposes in zonal resource credits (ZRCs). One ZRC is equal to one MW of deliverable seasonal accredited capacity, which is the net amount of capacity MISO calculates it can reasonably expect from a resource.[48]

Consumers' IRP projected that the entire J.H. Campbell plant would provide 1,346 ZRCs in 2024, its last full year of planned operation.[49] In recognition of the

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[45] *Id*. (Walz Rebuttal, 3 Tr 364-73 & Ex A-123; Blumenstock Rebuttal, 3 Tr 178-79).

[46] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, pp. 48, 55.

[47] MPSC Case No. U-21090-0777 (Settlement Agreement), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002gLkGAAU.

[48] MISO Knowledge Base, KA-01402, available at https://help.misoenergy.org/knowledgebase/article/KA-01402/en-us#:~:text=Zonal%20Resource%20Credits%20(ZRC)%20are,Seasonal%20Accredited%20Capacity%20(SAC); MISO, Resource Adequacy, available at https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc.

[49] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 33.

reduced capacity that would result from the retirement of J.H. Campbell, the settlement authorized Consumers to acquire the Covert gas plant, which Consumers has done.[50] At the time, the Covert plant was in the PJM regional transmission organization – but after acquiring it, Consumers redesignated the Covert plant as part of MISO Zone 7.[51] This action added 1,114 ZRCs to Zone 7 – almost enough by itself to offset the ZRCs removed by the Campbell retirement.[52]

The settlement also authorized Consumers to continue operating Units 3 and 4 of the Karn plant – peaking units that burn natural gas and oil – until 2031, rather than retire them in 2023 as originally planned.[53] This action maintained another 784 ZRCs in Zone 7 beyond what was in Consumers' original plan.[54] The settlement agreement also authorized Consumers to develop or acquire 250 ZRCs of new solar generation by mid-2025, increasing to 852 ZRCs by mid-2028; added 94 ZRCs of demand response and energy waste reduction by mid-2025; and added 71 ZRCs of new battery storage in 2024-2027.[55] The settlement also provided that Consumers would issue a solicitation for power purchase agreements (PPAs) that would provide capacity beginning in 2025/2026, right after J.H. Campbell's retirement.[56] The PPA solicitation would seek up to 500 MW of dispatchable generation, and up to 200 MW of clean energy resources.[57]

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[50] *Id*. at 5.
[51] *Id*. at 91.
[52] *Id*. at 50.
[53] *Id*. at 11.
[54] *Id*.
[55] *Id*. at 23.
[56] *Id*. at 6 – 7. In MISO, the planning year runs from June 1 through May 31.
[57] *Id*.

Overall, the plan approved in the settlement was projected to increase Zone 7's capacity by at least 127 ZRCs by June 2025 – an increase that will grow to at least 923 ZRCs by 2028, not including the 700 MW of additional capacity sought in the PPA solicitations.[58]

iv. MPSC approval of the settlement and affirmance on appeal

Consumers' IRP settlement agreement was supported by most parties in the case, including Consumers, Staff, the Attorney General, consumer advocates, a transmission company, commercial and industrial customers, businesses in the advanced energy sector, environmental groups, and third-party energy developers.[59] The MPSC approved the Settlement Agreement on June 23, 2022.[60] The state commission found that the plan embodied in the settlement "is the most reasonable and prudent means of meeting Consumers' energy and capacity needs."[61]

In reaching these conclusions, the MPSC specifically addressed resource adequacy.[62] After discussing the record evidence regarding the Covert plant, Karn units 3 and 4, new battery storage, and ongoing investments in solar, energy waste reduction, and demand response,[63] the MPSC concluded that "the approval of the settlement agreement will enhance resource adequacy in Zone 7 in both the near-term and long-term."[64] One party, Wolverine Power Supply Cooperative, appealed

[58] *Id.* at 24.
[59] *Id.* at 30 – 31.
[60] *Id.* at 87-93.
[61] *Id.* at 95.
[62] *Id.* at 90-93.
[63] *Id.*
[64] *Id.* at 92.

the MPSC's decision to approve the Campbell plant retirement. The Michigan Court of Appeals affirmed the MPSC. The court specifically addressed resource adequacy, quoted the MPSC's findings about the generating resource additions, and found that the state commission's decision was based on substantial evidence.[65]

v. Subsequent proceedings before the MPSC show that both Consumers' service territory and Michigan as a whole will have sufficient capacity this summer and for years to come

Filings in MPSC proceedings regarding capacity supply and resource adequacy demonstrate that there is no capacity shortfall. To the contrary, the most current available information is that both Consumers and MISO Zone 7 will have sufficient capacity this summer and for years to come. On June 10, 2025, Consumers reported that it now has a surplus of 273 ZRCs for this summer.[66] Consumers further reported that it expects J.H. Campbell will not contribute any ZRCs to the Company's summer position.[67]

Consumers' ZRC projections compare Consumers' available resources not just to projected actual demand but to the planning reserve margin requirement (PRMR). MISO establishes the PRMR as the amount of reserve margin target necessary to meet NERC's Loss of Load Expectation (LOLE) standard of 1 day in 10 years.[68] NERC

[65] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[66] *See* Attachment D, Consumers' Responses from June 10, 2025.

[67] *Id*.

[68] MISO Resource Adequacy Business Practices Manual, BPM-011-r31, p. 27, Section 3.4.2 LOLE Analysis; MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 9.

defines the LOLE as "the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand."[69]

For Michigan as a whole, the MPSC Staff finds in its annual capacity demonstration report that – except for one small municipal utility – all Michigan load serving entities "were able to procure the necessary capacity to demonstrate compliance for the current planning year in all four seasons" in Planning Year 2025-26.[70] The Staff Report also finds that there are more than enough resources in Zone 7 to meet the MISO Local Clearing Requirement (LCR) – which is the minimum amount of resources that must be located within a MISO local resource zone to meet the reliability standard.[71] While Zone 7 did not have enough internal resources to meet its entire PRMR, it is not required to do so under MISO rules, and the zone is able to import 785.5 ZRCs of external resources to meet its PRMR for the current planning year.[72]

Looking ahead, the Staff Report projects that Zone 7 will have more than enough resources to meet both its LCR and the PRMR in each of planning years 2026, 2027, and 2028.[73] Zone 7's LCR surplus will increase each year to reach 4,975 ZRCs by Planning Year 2028, and its PRMR surplus will increase each year to reach 3,428 ZRCs by Planning Year 2028.[74]

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[69] NERC Probabilistic Assessment Technical Guideline, August 2016, p. 2.
[70] MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 6.
[71] *Id*. at 16.
[72] *Id*.
[73] *Id*. at p. 26, Appendix C.
[74] *Id*.

vi. MISO approved the retirement of J.H. Campbell after a detailed study process governed by MISO's FERC-approved tariff

More than three years before the Secretary issued Order 202-25-3, MISO determined via a detailed technical study that retirement of J.H. Campbell would not materially impact reliability in MISO. That determination remains in effect.

Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires that the owner of a Generation Resource that is planning to suspend operations of all or a portion of that resource must notify MISO at least 26 weeks in advance by submitting a completed Attachment Y Notice.[75] The Tariff states that MISO will perform an Attachment Y Reliability Study to determine whether the Generation Resource is necessary for the reliability of the Transmission System based on analyses described in the Tariff and criteria in the MISO Business Practices Manuals.[76]

On December 14, 2021, Consumers submitted to MISO an Attachment Y notice of intent to suspend J.H. Campbell Units 1, 2, and 3 effective June 1, 2025.[77] After more than a year of study, MISO approved the suspension on March 11, 2022.[78] MISO stated that after reviewing the J.H. Campbell suspension for power system reliability impacts, MISO had determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,

[75] MISO Tariff, Section 38.2.7(a)(i).
[76] MISO Tariff, Section 38.2.7(c).
[77] Attachment C (Letter dated December 14, 2021, from Timothy J. Sparks, Consumers Energy, to Andrew Witmeier, MISO, and Attachment Y Notification of Generating Resources Change of Status).
[78] Attachment C (Letter dated March 11, 2022, from Andrew Witmeier, MISO, to Timothy J. Sparks, Consumers Energy, re: Approval of Campbell Units 1, 2 & 3 Attachment Y Suspension Notice).

2 & 3 may suspend without the need for the generators to be designated as a System Support Resource ('SSR') units as defined in the Tariff."[79]

On May 27, 2025, MISO requested that Consumers submit a modified Attachment Y request with a new suspension start date of August 21, 2025, consistent with the date in Order 202-25-3.[80] Consumers submitted the modified Attachment Y notice with the new date on May 28, 2025.[81] On May 30, 2025, MISO notified Consumers that with the modification, "the Attachment Y remains as is, still approved, except with a new/different start date."[82]

D. The Order

On May 23, 2025, the Secretary of Energy issued the Order pursuant to section 202(c) of the Federal Power Act, determining that an emergency exists in the region of the country served by MISO "due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" and ordering Consumers and MISO to ensure the continued operation of J.H. Campbell for at least 90 days notwithstanding the longstanding plan to retire the facility on May 31, 2025. In issuing the Order, the Department issued a press release that, like Executive

[79] *Id*.
[80] Attachment C (Email dated May 27, 2025, from Huaitao Zhang, MISO, to Kathy Wetzel, Consumers Energy).
[81] Attachment C (Email dated May 28, 2025, from Rachael Moore, Consumers Energy to Huaitao Zhang, MISO).
[82] Attachment C (Email dated May 30, 2025, from Marc Keyser, MISO, to Rachael Moore, Consumers Energy).

Order 14262, states the Order "is in accordance with President Trump's Executive Order: Declaring a National Energy Emergency."[83]

Over four short paragraphs, the Order outlines the "emergency situation" allegedly necessitating invocation of section 202(c) authority. It points primarily to "*potential* tight reserve margins during the summer 2025 period," citing to the North American Electric Reliability Corporation (NERC) 2025 Summer Reliability Assessment, including the statement that MISO is "at elevated risk of operational reserve shortfalls during periods of high demand or low resource output."[84] The Order then describes the retirement of thermal generation capacity including the retirement of approximately 2,700 MW of coal-fired capacity in Michigan since 2020 and the scheduled May 31, 2025, retirement of J.H. Campbell.[85] The Order acknowledges Consumers' acquisition of 1,200 MW of replacement natural gas capacity and MISO's April 2025 conclusion that its auction resulted in "demonstrated sufficient capacity,"[86] but does not reference, let alone consider, the extensive processes that MISO and the MPSC undertook to evaluate and mitigate any reliability or resource adequacy risk that would be caused by the retirement of J.H. Campbell.[87] Nor does the Order describe any actions that MISO or Consumers have taken or could take to mitigate any alleged emergency conditions short of ordering the continued operation of the plant. Rather, it relies almost exclusively on:

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[83] DOE Press Release (May 23, 2025) available at https://www.energy.gov/articles/energy-secretary-issues-emergency-order-secure-grid-reliability-ahead-summer-months.
[84] DOE Order 202-25-3 at 1 (emphasis added).
[85] *Id.* at 1.
[86] *Id.* at 2.
[87] *See* Section II.C *supra*.

- The general statement in NERC's 2025 Summer Reliability Assessment that there is anticipated to be "elevated risk of operating reserve shortfalls"
- Language in MISO's Planning Resource Auction Results for Planning Year 2025-26 that, "for the northern and central zones, which includes Michigan, 'new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources,'" and that the results "reinforce the need to increase capacity" and,
- Language from the MISO Auction Results that the summer months have, relative to other times, the "highest risk and tighter supply-demand balance."[88]

The Order concludes that "additional dispatch of the Campbell Plant," for the 90-day duration of the order and on conditions contained in the order, "is necessary to best meet the emergency and serve the public interest."[89] As a result, the Order mandates that:

- MISO and Consumers Energy take all necessary steps to ensure the Campbell Plant is available for dispatch;[90]
- MISO employ economic dispatch of the plant, and that Consumers comply with all such dispatch orders;[91]
- All operation of J.H. Campbell "must comply with applicable environmental requirements . . . to the maximum extent feasible while operating consistent with the emergency conditions."[92]
- MISO submit reports to DOE on plant operations, environmental impacts, and actions taken to comply with the Order.[93]
- "Relevant governmental authorities" take such action as necessary to enable MISO to effectuate the dispatch and operation of the units.[94]
- Consumers request any necessary revisions or waivers to effectuate the order with FERC.[95]

III. STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

[88] DOE Order 202-25-3 at 2.
[89] DOE Order 202-25-3 at 2.
[90] *Id.* at 2 (Ordering Paragraph A).
[91] *Id.* (Ordering Paragraph A).
[92] *Id.* at 3 (Ordering Paragraph C).
[93] *Id.* at 3 (Ordering Paragraph B, D).
[94] *Id.* at 3 (Ordering Paragraph E).
[95] *Id.* at 3 (Ordering Paragraph F).

As explained in Section IV below, the Michigan Department of Attorney General submits the following statement of issues and specifications of error:

1. The Order is contrary to law because it fails to establish the existence of an emergency under section 202(c) or the Department's regulations implementing section 202(c). The statutory text, legislative history, judicial construction and DOE's regulations all confirm that an "emergency" is an occurrence that is sudden, unexpected and requiring immediate action. The Order introduces no facts that would satisfy that definition. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371; *Richmond Power and Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978); *Otter Tail Power Co. v. Fed. Power Comm*., 429 F.2d 232, 233-34 (1970).

2. The Order is contrary to law because it exceeds the Department's statutory authority. Abusing a statute meant only for emergencies, the Order intrudes on authority reserved to States and to other federal regulators to regulate resource adequacy. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy, or the authority to decide which power plants may retire except for so long as a true emergency exists. The Department may not "discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority." *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

3. The Order fails to present substantial evidence for its emergency determination and fails to exercise reasoned decision-making by ignoring critical facts and shortcomings in its analysis. Specifically, the Order: (i) presents a discussion of the NERC 2025 Summer Reliability Assessment that is unreasoned, incomplete, and that fails to substantiate the existence of an emergency; (ii) the Order's apparent reliance on generator retirements in Michigan as evidence of an emergency is unreasonable; (iii) the Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless, (iv) the Order fails even to acknowledge that MISO approved the retirement of J.H. Campbell through the study process governed by its FERC-approved tariff; (v) the Order makes no effort to review the proceedings before the MPSC, or to note any consultation with Michigan officials as required by 42 U.S.C. § 7113; (vi) the Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate. *E.g. Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017) (order under the Federal Power Act must reflect "a principled and reasoned decision supported by the evidentiary record" (quotation marks omitted)); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (agency must examine the relevant data and articulate a satisfactory

explanation for its action including a rational connection between the facts found and the choice made); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962) (an "agency must make findings that support its decision, and those findings must be supported by substantial evidence").

4. The Order is arbitrary and capricious and contrary to law because section 202(c) provides no authority for the Department to command a generator to engage in "economic dispatch." 16 U.S.C. § 824a(c); *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001) (absent statutory authorization, an agency's "action is plainly contrary to law and cannot stand").

5. The Order is arbitrary and capricious and contrary to law because the Department failed to limit its remedy as required by section 202(c)(2). The Order adheres to neither the temporal constraint nor the environmental constraints imposed by section 202(c)(2). 16 U.S.C. § 824a(c)(2).

6. The Order violates the National Environmental Policy Act because it fails to assess the environmental consequences of a major federal action significantly affecting the human environment. 42 U.S.C. § 4321; *et seq*.

IV. REQUEST FOR REHEARING

A. The Department Has Failed to Establish the Existence of an Emergency under Section 202(c) or the Department's Regulations Implementing Section 202(c).

i. Congress limited DOE's authority under section 202(c) to the unique circumstances of war or emergency

Section 202(c) confers an extraordinary power. Enacted in 1935, section 202(c) empowered the Federal Power Commission to command action from market participants and – crucially – to do so freed from most of the core procedural safeguards, jurisdictional boundaries, and substantive limitations that undergird the rest of the Federal Power Act. While the rest of the Act authorizes Commission action

only after opportunity for hearing,[96] section 202(c) allows the Commission (now the Department) to act on its own motion and without prior notice. And in profound contrast to the rest the Federal Power Act and general utility law principles,[97] section 202(c) empowers the Department to require utilities to incur costs – through a command to provide generation or transmission service – without first considering the impact to ratepayers or whether the resulting rates will be just and reasonable.

It comes as no surprise, therefore, that when Congress granted the Commission this extraordinary power, Congress restricted its use to extraordinary circumstances. Section 202(c) authorizes action only "[d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." The Act permits some measure of flexibility with respect to what type of events may cause the emergency, allowing for "other causes" beyond those enumerated. But the Act is clear that any such event, including a "shortage of electric energy," must be one that constitutes an "emergency."

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[96] *See e.g.*, 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o & 824p.

[97] Two cornerstones of the law of regulated utilities are the filed rate doctrine and the rule against retroactive ratemaking. As FERC has explained, "a central purpose of the filed rate doctrine and the rule against retroactive ratemaking is to protect ratepayers from being subjected to an additional surcharge above the rate on file for service already performed." *Old Dominion Elec. Coop.*, 154 FERC ¶ 61,155 (2016). In its June 6, 2025, complaint filed in FERC Docket No. EL25-90, Consumers asserts that the filed rate doctrine and the rule against retroactive ratemaking are inapplicable in the context of an order under section 202(c).

Because the Act does not define "emergency," the Department must look first to the public meaning of that word at the time of enactment. Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "sudden or unexpected appearance or occurrence . . . . An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency." Contemporary dictionaries likewise define "emergency" to refer to a circumstance that is "unexpectedly arising, and urgently demanding immediate attention."[98]

These definitions accord with the legislative history of the Federal Power Act, which characterized section 202(c) as an authority to be used in response to "crises":

> This is a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose. Drought and other natural emergencies have created similar crises in certain sections of the country; such conditions should find a federal agency ready to do all that can be done in order to prevent a break-down in electric supply.[99]

The few courts that have had occasion to opine on the meaning of "emergency" in section 202(c) have likewise emphasized that the provision applies in very limited circumstances, and not as a tool to address longer-term, structural concerns. In *Richmond Power and Light v. FERC*, the D.C. Circuit upheld the Commission's judgment that the dependence on foreign oil occasioned by the 1973 oil embargo was

[98] *See Acuity Ins. Co. v. McDonald's Towing & Rescue, Inc.,* 747 F. App'x 377, 380–81 (6th Cir. 2018) (addressing a statute that leaves "emergency" undefined and quoting 7 Oxford English Dictionary 231 (2012) among others to supply a definition).
[99] S. Rep. No. 74-621 at 49 (1935).

not an "emergency" under the Act, noting that section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[100]

In *Otter Tail Power Co. v. Fed. Power Comm'n,* the U.S. Court of Appeals for the Eighth Circuit described section 202(c) as enabling the Commission to "react to a war or natural disaster." The court also distinguished section 202(c) from section 202(b), under which the Commission may also order interconnections, but only after a hearing. The court explained that, in contrast to section 202(c), which "enables the Commission to proceed without notice or hearing" to address immediate crises, section 202(b) "applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[101]

Through its regulations, the Department has also interpreted "emergency" for purposes of section 202(c) to mean circumstances that arise suddenly and unexpectedly:

> "Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities.[102]

In summary, the plain meaning of the statutory text, its legislative history, judicial construction, and the Department's own regulations all establish that an

[100] 574 F.2d 610, 615 (D.C. Cir. 1978).
[101] 429 F.2d 232, 234 (8th Cir. 1970).
[102] 10 C.F.R. § 205.371.

"emergency," including one occasioned by a "shortage of electric energy," must be sudden, unexpected, and demanding of "immediate action."

ii. The Order fails to present facts establishing an emergency under section 202(c) or the Department's regulations

Even taken as complete and accurate claims (which they are not), the factual assertions made in the Order fail to describe an "emergency." The Order does not claim that the retirement of J.H. Campbell was sudden or unexpected. Nor could it. The retirement of J.H. Campbell was carefully planned over a period of years and was approved by the MPSC through a public proceeding. Further, Consumers' plan to retire J.H. Campbell included a commitment to procure replacement resources that improved its capacity position. And Consumers' proposal to retire J.H. Campbell was approved in advance by MISO after a thorough review of its impact on reliability.

Nor did the publication of NERC's 2025 Summer Reliability Assessment in May 2025 transform a long-planned retirement into an event with sudden or unexpected implications requiring immediate action. The Order notes that the 2025 NERC Summer Reliability Assessment characterizes MISO as being at an "elevated risk of operating reserve shortfalls." But NERC's "elevated risk" designation in no way signifies an emergency condition. "Elevated risk," it should be emphasized, falls *below* NERC's highest risk designation: that of "high" risk.[103] NERC's decision not to place MISO in the highest risk category in its Summer Reliability Assessment is

[103] The "High" risk designation refers to a risk of shortfall during normal peak conditions, whereas the "Elevated" risk designation refers to a risk of shortfall during above-normal peak conditions. See Attachment A, NERC, 2025 Summer Reliability Assessment at 6.

in itself powerful evidence that there is no "emergency" stemming from a lack of operating reserves.

The "elevated risk" designation is also far from unusual. In the same report, NERC also designated the systems overseen by SPP, the Electric Reliability Council of Texas (ERCOT), and the New England Independent System Operator (ISO-NE) as at "elevated risk."[104] Except for 2022, when it was designated as "high" risk, MISO has been designated as "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[105] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021.[106] In effect, what the Order implies through its reliance on the NERC report's "elevated" risk designation, is that the fifteen states of MISO – along with large swaths in the rest of the United States – have been in an uninterrupted state of emergency for many years on end. This interpretation, if credited, would effectively read the word "emergency" out of section 202(c).

The Order's hand-waving reference to "potential tight reserve margins" identified in the 2025 NERC Summer Reliability Assessment likewise fails to describe an emergency. The very fact that the Order attempts to rely on "potential" future conditions itself contradicts the notion that MISO is presently facing an

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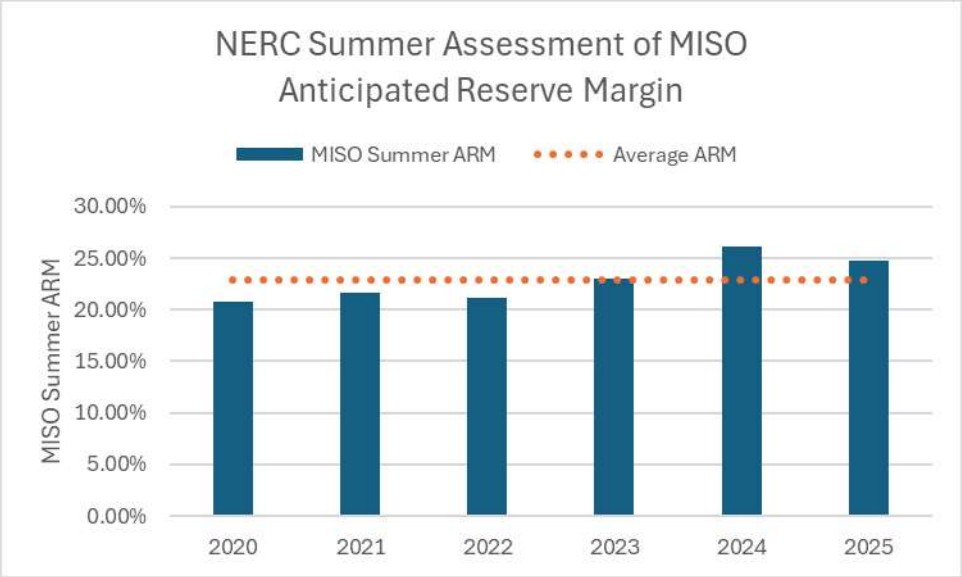
[104] *Id*.

[105] *See* NERC Summer Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

[106] *See* NERC Winter Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

emergency as conceived under section 202(c). Moreover, the actual reserve margins in MISO this summer do not support an emergency determination. The NERC report calculated MISO's anticipated reserve margin for Summer 2025 as 24.7%.[107] This figure substantially exceeds NERC's "Reference Margin Level" for MISO of 15.7%,[108] which is the level that NERC has "established for the areas to meet resource adequacy criteria."[109] MISO's anticipated reserve margin of 24.7% is also *higher* than its average of recent years. The chart below shows the anticipated reserve margin for MISO as calculated in the NERC Summer Reliability Assessment for each year.[110] The chart shows that the 2025 anticipated reserve margin of 24.7% exceeds the 2020-2025 average of 22.9%. Again, the Order has failed to describe a circumstance that is "unexpected," "sudden" or "demanding of immediate attention."



[107] Attachment A, NERC, 2025 Summer Reliability Assessment at 10.
[108] *Id*. at 44.
[109] *Id*. at 15.
[110] *See* NERC Summer Reliability Assessments years 2020 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

The other factual assertions in the Order likewise fail to describe an emergency. The Order devotes one of its few substantive paragraphs to explaining that various generation units have retired in Michigan, reaching back as far as 1997.[111] But generation units retire everywhere as part of the normal, continuous cycle through which old units are replaced with new ones. The unsurprising fact that generation units have retired in Michigan over the last 28 years says nothing about whether there is presently adequate generation in the State, and even less about whether an emergency exists in the region as a whole.

The Order then points to the results of the April 2025 MISO Planning Resource Auction. But these results explicitly contradict the claim that an emergency exists in MISO. The Order acknowledges MISO's conclusion that the auction "demonstrated sufficient capacity." In fact, the Order truncates this quote, which stated in full that: "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."[112] Remarkably, the Order attempts to brush aside the obvious import of this conclusion, preferring instead to focus on the second half of the sentence. But the second half of that sentence merely refers to the fact that the summer price for capacity in MISO, which separates the auction results by season, is high*er* and has a tight*er* supply/demand balance than those of the fall, winter and spring seasons (a fact illustrated by the chart below the header text).

[111] Order at 1.
[112] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 12.

This sentence does not indicate any kind of shortfall in the summer season, much less an emergency shortfall.

The Order also quotes from a slide that states "for North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[113] But this slide is simply noting that the total capacity of resources *offered* into the 2025 auction in the North/Central region was lower than what was offered into the 2024 auction. This slide does not say that the total amount of capacity *procured* in the North/Central region through the auction was inadequate. In other words, this slide is in no way inconsistent with the conclusion in the same report that the "2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels."[114] Further, even as a characterization of the total capacity offered into the auction, the Order ignored a crucial fact in this slide. The slide shows that the reason for the decrease in capacity offered was not because of a decrease in physical generating capacity, but because of a change in the capacity accreditation of various resources—most notably, the very "dispatchable generation" that the order prioritizes. This change in MISO's capacity accreditation methodology occurred over the previous year.[115] The bar chart in Attachment B shows a reduction in accredited capacity for gas and coal of 3.4 GW, which is greater than the overall reduction in offered

[113] *Id*. at 13.
[114] *Id*. at 12.
[115] *Midcontinent Independent System Operator, Inc*., 189 FERC ¶ 61,065 (Oct. 25, 2024).

capacity.[116] In other words, MISO concluded that coal (and gas) resources, such as J.H. Campbell, should be deemed to contribute less to capacity requirements than it had previously assumed.

B. Abusing an Authority Meant for True Emergencies, the Order Intrudes on Authority Reserved to States and to Other Federal Regulators.

i. Resource adequacy is regulated by the states, and by FERC under other provisions of the Federal Power Act

Resource adequacy refers to the capacity of an electric power system to meet demand reliably at all times, including during system peaks and through potential outages. Resource adequacy is "measured at the system level to capture the overall impact of outages of individual components including generators and transmission."[117] Resource adequacy planning is the process by which utilities and system operators, under regulatory supervision, ensure resource adequacy. Resource adequacy planning involves technical and economic considerations that go into determining what resources are added to the grid and which resources should retire and when.

With respect to regulatory oversight for resource adequacy, section 201 of the FPA, 16 U.S.C. § 824(b)(1), reserves authority over generation facilities to the states. It states in pertinent part: "The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over*

[116] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 13.
[117] NREL, Resource Adequacy Basics, available at https://www.nrel.gov/research/resource-adequacy.

facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[118]

Some states have retained this authority over resource adequacy in its entirety.[119] Others have directed their utilities to join RTO/ISOs that, through their tariffs, impose resource adequacy requirements. Those RTO/ISOs also generally establish markets that allow market participants to buy and sell capacity and thereby to facilitate market entry and exit decisions based on price signals. Resource adequacy requirements in RTO/ISO tariffs have been held to be practices affecting wholesale rates subject to the jurisdiction of FERC under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d & 824e.[120]

In Michigan, the regulation of resource adequacy planning has both a state and federal aspect. As a member of MISO, Consumers has a capacity obligation under the MISO tariff. MISO's resource adequacy requirements, however, are designed to be complementary to the primary role of the states in ensuring resource adequacy.[121]

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[118] *Id*. (emphasis added).

[119] *See Devon Power LLC et al.,* 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[120] *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).

[121] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, 62,606 at P 13 (2020) ("approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities ... within the [MISO] region."); *see also id*. ("MISO's proposed Tariff language

Consumers' investment decisions are regulated by the MPSC. Through the state IRP process (described in Section II.C above), the MPSC exercises regulatory authority over Consumers in order to ensure that the utility obtains the amount of capacity it needs to meet its obligations under the MISO tariff, and that it does so at the best value to ratepayers, and with a composition of resources that otherwise complies with state law, including state environmental requirements.

ii. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy

The Order indicates that the Department believes it has the authority to decide which power plants may retire and when, not based on the kind of real emergency that has justified past action, but rather based on its own policy preferences. The Department appears to want to place its own judgment about operating reserve margins ahead of MISO's, and its own preference for which resources are employed to maintain resource adequacy ahead of Michigan's. In effect, the Department appears to read section 202(c) so as to give itself authority to regulate resource adequacy. Any ambiguity on this point was put to rest by the Department's June 13 letter referring cost recovery issues for J.H. Campbell to FERC. In that letter, the Department, through counsel, acknowledged that resource adequacy concerns

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explains that the resource adequacy requirements 'are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction.' In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's Auction is not—*and has never been*—the primary mechanism for its [Load Serving Entities] to procure capacity."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]").

motivated the Order and went so far as to purport to dictate whether J.H. Campbell would be counted as a capacity resource pursuant to the MISO tariff.[122]

Section 202(c) does not provide the Department with the authority it claims. Had Congress intended to vest regulatory authority over resource adequacy in section 202(c), – displacing both state law and sections 205 and 206 of the Federal Power Act, – it would have stated so clearly. But of course it did not. The authorizing language says no more than that DOE may "require by order . . . such generation . . . of electric energy as in its judgment will best meet the emergency and serve the public interest." Indeed, it defies logic that, had Congress intended to empower DOE to be the general decider of which power plants may retire across every utility and independent power producer across the entire country – a function with profound implications for rates, state sovereignty, and a broad array of other stakeholder interests – that Congress would have done so through what may be the only provision in the Federal Power Act that empowers the regulator to act without first assessing the effect on ratepayers or seeking public input, and one of the only provisions that extends to otherwise non-jurisdictional utilities such as public power entities and those in ERCOT.

But even if the text of section 202(c) could, theoretically, be stretched to such an expansive reading (which it cannot), the United States Supreme Court has emphatically rejected statutory interpretations whereby an agency "claim[s] to discover in a long-extant statute an unheralded power representing a transformative

[122] FERC Docket No. EL25-90, submission of Dep't of Energy, June 13, 2025 ("Because the May 23, 2025 Order is predicated on the shortage of facilities for the generation of electric energy and other causes, such as resource adequacy concerns, the Campbell plant shall not be counted as a capacity resource.").

expansion in its regulatory authority."[123] That is exactly what the Department seeks to do here. It seeks to discover in a 90-year-old statute a basis to exercise much broader regulatory authority than it ever has in the past. While it is true, as we explain above in section II.A, that the Department has used section 202(c) to delay power plant retirements on three occasions over the 90-year history, it has always done so at the request of a system operator or governmental body and in a manner narrowly tailored to prevent a concrete and particularized emergency. It has never done so simply to impose its policy preferences ahead of the judgment of those bodies responsible for resource adequacy.

C. The Order Fails to Present Substantial Evidence for its Emergency Determination and Fails to Exercise Reasoned Decision-making by Ignoring Critical Facts.

The Order relies on three sources of evidence for its emergency determination: the NERC 2025 Summer Reliability Assessment, generator retirements in Michigan, and the results of MISO's 2025 Planning Resource Auction. None of these three sources provide evidence that an emergency exists. By relying on these sources, and by misconstruing each of them, the Order fails to exercise reasoned decision-making.

The Order also entirely ignores several other critical facts and considerations. The Order ignores the fact that MISO approved the deactivation of J.H. Campbell. The Order ignores the conclusions of the MPSC proceeding that approved the retirement of J.H. Campbell. And even if it were correct that a capacity shortfall

[123] *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

exists in MISO, the Order fails to explain why preventing the retirement of J.H. Campbell through an emergency measure is necessary to address the shortfall.

i. The Order's discussion of the NERC 2025 Summer Reliability Assessment is unreasoned and incomplete

As explained above in Section IV.A, the Order's discussion of the NERC 2025 Summer Reliability Assessment is both incomplete and unreasoned. Specifically, the Order fails to explain (i) why the NERC report supports an emergency finding for MISO given that NERC did not put MISO in the "high" risk category, (ii) why NERC's designation of MISO as at "elevated" risk provides evidence of a "sudden" or "unexpected" circumstance given that MISO has been at this risk level or higher for years running, and (iii) why the "potential tight reserve margins" identified in the NERC report constitute an emergency given that MISO well exceeds the NERC reference margin level and even exceeds its own average Summer anticipated reserve margin over the 2020 – 2025 period.

ii. The Order's apparent reliance on generator retirements in Michigan is unreasonable

The Order attempts to support its emergency finding by recounting the fact that various power plants have retired in the state of Michigan.[124] As explained above, because power plant retirements are a regular occurrence in the electric power sector, the Order's discussion of this topic fails to present even *prima facie* evidence of an emergency. It also fails to exhibit reasoned decision-making in two key respects. First, it is unreasonable to point to capacity retirements in isolation

[124] Order at 1.

without also considering all the other factors that contribute to resource adequacy. Such factors include capacity additions, changes in load, load shape and load flexibility, demand response, transmission access to external resources, etc. Of course, MISO *did* consider all those factors in the modeling that went into the Attachment Y process through which it approved the deactivation of J.H. Campbell.[125]

Second, the Order fails to explain how power plant retirements in Michigan are related to the emergency the Department purports to identify. In past orders where the Department has used section 202(c) to delay a power plant's retirement, the Department has acted on application of a utility or system operator to address a discrete, localized emergency that would be caused by the impending retirement.[126] The Department makes no such claim to geographic specificity here. Rather, the remainder of the "Emergency Situation" section of the Order appears to describe a purported emergency throughout MISO, insofar as it relies on NERC's general statements about MISO reserve margins and the results of the MISO Planning Resource Auction. Thus, the Order fails to explain why it is relying on power plant retirements in a single state—Michigan—to support its claim that an emergency exists in the region as a whole.

iii. The Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless

[125] *See* MISO Transmission Planning Business Practices Manual, BPM-020-r32 Section 6.2 (Generator Retirement and Suspension Studies and System Support Resources), Section 6.2.3 (Study Scope Development).
[126] *See* Section II.A *supra*.

As explained in Section IV.A above, the Order cites to the MISO planning reserve auction report while ignoring the statement in that report that: "The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels." It is entirely unreasonable for the Department to cite this report as evidence of an emergency when the report has concluded exactly the opposite. The Order's effort to focus on other aspects of the report are equally unreasonable. The unremarkable statement that summer prices are higher than prices in other seasons and therefore reflect a tighter supply/demand balance falls far short of providing evidence for an emergency. Likewise, the Order's reliance on the fact that less capacity was *offered* in the 2025 auction than was offered into the 2024 auction hardly describes an emergency. Further, the Order fails to note the information conveyed in the slide it quotes from, which shows that the only material change between 2024 and 2025 was a result in a change in capacity accreditation values rather than a change in physical resources available.

iv. The Order fails to acknowledge that MISO approved the retirement of J.H. Campbell

As explained in Section II.C above, after a robust, technical, and considered process, MISO approved the retirement of the three J.H. Campbell units pursuant to the study process governed by its tariff. MISO concluded that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria." As the system operator, MISO has more in-depth knowledge of its system than the Department does. The Department should have explained why it reached a

different conclusion than MISO. Instead, the Order failed even to mention that MISO conducted this study and approved the retirement.

v. The Order makes no effort to review the findings of the MPSC or to demonstrate consultation with Michigan as required by 42 U.S.C. § 7113

The Order acknowledges that Consumers acquired the Covert gas plant, but in all other respects fails to acknowledge the MPSC proceeding that approved Consumers' IRP settlement entailing retirement of J.H. Campbell. As explained above in Section II.C, acquiring the Covert gas plant was not the only action Consumers took as part of that IRP. The IRP also delayed the retirement of the peaking units at the Karn facility and included the acquisition of other new resources, with the result that Consumers' capacity position was set to improve materially even after the retirement of J.H. Campbell. The Order also ignores the Michigan capacity demonstration proceedings that found both Consumers and MISO Zone 7 have sufficient capacity resources in 2025 and in the years to come.

Section 103 of the Department of Energy Organization Act, 42 U.S.C. § 7113, provides:

> Whenever any proposed action by the Department conflicts with the energy plan of any State, the Department shall give due consideration to the needs of such State, and where practicable, shall attempt to resolve such conflict through consultations with appropriate State officials.

The Order plainly conflicts with Michigan's energy plan, as reflected in the MPSC's approval of Consumers' IRP. Equally clearly, the Order does not give "due consideration" to the needs of Michigan. Nor does it appear that the Department

made any attempt to resolve the conflict it created through consultation with the appropriate State officials. The Department, therefore, has failed to comply with Section 103 of the Department of Energy Organization Act. A practical consequence of the Department's apparent failure to consult with the State is that the Order lacks basic information related to its action, including the Order's inexplicable failure to accurately state the capacity of J.H. Campbell, the lack of awareness as to the operational status of Unit 2, the understatement of resources Consumers acquired to replace J.H. Campbell, and the omission of any reference to the reliability analysis undertaken by the State.

vi. The Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate

Even accepting the Order's contention that there exists a capacity shortfall in MISO, it does not follow that commanding the continued operation of J.H. Campbell is the best or even an appropriate means of alleviating the shortfall. The Order does not assert that there is a local problem on the grid that only J.H. Campbell can solve. In this respect, the Order departs markedly from past uses of section 202(c) and from the Department's regulations implementing section 202(c), which state that: "Actions under this authority are envisioned as meeting a specific inadequate power supply situation."[127]

Rather, the emergency that the Order purports to identify – "potential tight reserve margins" – is one that spans the entire fifteen-state MISO region and one

[127] 10 C.F.R. § 205.371.

that could presumably be addressed by any number of actions across MISO. And, given that J.H. Campbell amounts to well less than 1% of generation capacity in MISO, there likely were options available that would have had a much greater impact on the overall balance of supply and demand. Further, because J.H. Campbell is an over 60-year-old facility in a largely degraded operational state, there presumably were alternative actions available that could have met the purported need with higher levels of reliability.

Yet the Order does not acknowledge any alternatives or explain whether less burdensome measures were exhausted before taking this action. The question of whether alternative measures could have been used to address the "emergency" is made more challenging by the fact that the Order never quantifies the extent of the emergency it purports to identify within MISO. But that omission merely highlights rather than excuses the deficiencies of the Order.

One possible alternative may have been demand-side measures. The Department's regulations require applicants seeking an order under section 202(c) to provide a "description of any conservation or load reduction actions that have been implemented . . . [and a] discussion of the achieved or expected results."[128] In the Yorktown case, the Department required Dominion to exhaust all demand response measures before dispatching the facility.[129] And yet here the Department failed to make any inquiry or even to consider whether demand-side measures could have

[128] 10 C.F.R. § 205.373.
[129] *See* DOE Order No. 202-17-4 (Sept. 14, 2017) ("PJM and Dominion shall exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Unit 1 or Yorktown Unit 2.")

addressed the purported emergency. Similarly, the Department's regulations require applicants to describe their efforts made to obtain additional power through third parties.[130] But again, the Department failed to consider whether MISO could alleviate the purported emergency through access to external resources.

D. The Department's Direction that MISO Operate J.H. Campbell Using "Economic" Dispatch Is Inconsistent with its Authority under Section 202(c).

The Department's Order directs MISO to "take every step to employ economic dispatch of the Campbell Plant."[131] The Order indicates that the use of economic dispatch is intended to "minimize cost to ratepayers."[132] However, this mandate to MISO exceeds the authority provided by section 202(c). Nor is the use of economic dispatch likely to serve the public interest.

The Order does not define "economic dispatch" or specify how it intends MISO to dispatch the units. In the Energy Policy Act of 2005, Congress adopted a definition of "economic dispatch" that generally conforms to accepted use: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[133] Drawing on this statutory definition, FERC issued a 2006 report, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations,* that provides a useful explanation of the 2-step process that

[130] 10 C.F.R. § 205.373(h).
[131] Order at 2 (Ordering Paragraph A)
[132] *Id.*
[133] *See* section 1234(b) of the Energy Policy Act of 2005, 42 U.S.C. § 16432(b);

regions have, in practice, adopted to implement economic dispatch.[134] This process includes (1) *day ahead unit commitment*, in which grid operators commit generators to be online in the subsequent 24-hour period, determined based on which generators will be most economic, taking into account each unit's physical operating characteristics, and (2) *unit dispatch*, in which grid operators dispatch committed resources at specified levels, in real-time, determined based on what set of units will minimize total system costs, given actual load, generation, and transmission conditions and constraints.[135]

Section 202(c) authorizes DOE to direct certain actions during emergency conditions. As relevant here, section 202(c)(1) provides DOE with "authority . . . to require by order . . . such generation . . . of electric energy as in its judgment will *best meet the emergency* and serve the public interest." In other words, DOE's power extends only to ordering actions that meet the emergency that the Department has identified.

But economic dispatch is not a rational response to the types of emergencies that section 202(c) authorizes DOE to address. Nor would economic dispatch be a rational approach to addressing the circumstance that DOE is purporting to address with its order—a potential capacity shortfall—if that were within its authority under section 202(c). In fact, DOE has made no effort to explain why economic dispatch is a rational remedy here, — let alone the best means of meeting the "emergency" that it

[134] FERC, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations* (July 31, 2006), https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.
[135] *Id.* at 5-6.

has identified. And, unlike prior Orders, here DOE acted on its own motion without a request or input of MISO and so cannot rely on the expertise of the cognizant grid operator or operating utility requesting a specific remedy to justify the appropriateness of economic dispatch.[136]

i. Economic dispatch is not a rational response to a shortage of electric energy

Economic dispatch is the standard procedure by which operators (such as MISO) operate the grid. However, outside of normal operations, including during emergency conditions, generation units may be selected "out of merit order" as necessary to ensure that generation and load are balanced. Operating a unit pursuant to economic dispatch is, necessarily, inconsistent with operating the unit in a manner designed to address an emergency, such as a shortage of electric energy. If a unit would be dispatched under purely economic conditions, but electric demand can alternatively be met with other existing supply (or demand response) resources, that unit is *not* necessary to meet the emergency. However, if the unit would, in fact, be needed to address a shortage, it should be dispatched regardless of whether its offer price is above or below the market-clearing price. In other words, economic dispatch is not a dispatch rule that is reasonably tailored to ensure that the unit addresses a shortage of electric energy.

[136] *See* DOE Order No. 202-18-1 at 4 (The statute requires only that the Secretary use his or her best judgment to meet the emergency and serve the public interest. In this situation, the expertise of the applicant was an important factor. The Department received an application from PJM, which . . . holds the highest-level, federally-regulated reliability responsibilities for the system it manages.), https://www.energy.gov/sites/prod/files/2017/11/f46/Summary%20of%20Findings%20Order%20No.%202-18-1.pdf.

Prior DOE orders have contained significant operating constraints to satisfy this statutory requirement. Orders have specified that units subject to a section 202(c) order should only run in specific emergency alert conditions — specific conditions in which grid operators have exhausted the capacity of other available generators, imports, and voluntary demand response, and failure to call on additional generation will risk involuntary load shed.[137] Similarly, in its order to delay retirement of the Yorktown plant, DOE recognized that dispatch of the units must be constrained, that continued operation of the units under the standard methodologies used by the local utility (Dominion Energy Virginia) and grid operator (PJM) would not be appropriate, and that Dominion and PJM must exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2.[138] Similarly, in the case of its 2005 District of Columbia Department of Public Service order, the Department directed Mirant to maintain its facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[139] And in its 2017 order regarding GRDA's Grand River Energy Center

[137] DOE Order No. 202-21-1 (authorizing operation only during Energy Emergency Alert Level 2 or Level 3); DOE Order No. 202-21-2 (authorizing operation only during Energy Emergency Alert Level 2 or higher); DOE Order 202-22-1 (same); DOE Order No. 202-22-3 (same); DOE Order No. 202-22-4 (same).

[138] DOE Order No. 202-17-2 (providing that Yorktown units 1 and 2 may be dispatched "only when called upon to address reliability needs" and directing PJM and Dominion Energy Virginia "to provide the dispatch methodology to the Department upon implementation, and to report all dates on which Yorktown Units 1 and 2 are operated"); DOE Order No. 202-18-1 at 3 (relying on the fact that DOE "require[d] PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2").

[139] DOE Order No. 202-05-3 (Dec. 20, 2005), District of Columbia Public Service Commission at 10 – 11.

Unit 1, the Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[140] DOE's Order contains no such constraints, and it fails to explain or justify such deviation from consistent past practice.

ii. Economic dispatch is an arbitrary response to any alleged capacity shortage

Indeed, even on DOE's own terms, the justification for the Order does not support ordering J.H. Campbell to operate whenever MISO's economic dispatch rules would select it to operate. The Order points specifically to questions about the sufficiency of electric *capacity* and the ability of MISO to meet load during periods of high demand and low resource output over the next 90 days as the basis for its emergency determination.[141] For example, the Order points to NERC's 2025 Summer Reliability Assessment, and specifically to the finding that "MISO is at elevated risk of operating reserve shortfalls *during periods of high demand and low resource output*."[142] The order repeatedly raises concern about the risk of "*capacity* shortfall for MISO," the extent to which *capacity* of certain generating resources have retired or may retire, and that MISOs' *capacity* market auction (the Planning Resource Auction Results for Planning Year 2025-26) "reinforce the need to increase *capacity*."[143] Dispatch of J.H. Campbell at any time other than a specifically identified operating reserve shortfall (e.g., a concrete expected supply/demand imbalance)—let

[140] DOE Order No. 202-17-1 at 2.
[141] Order at 1-2
[142] Order at 1 (emphasis added).
[143] Order at 1-2.

alone dispatch whenever the plant would be called upon by MISO's economic dispatch algorithm—is *not* necessary to address the type of emergency that the DOE order identifies. Even if the order sufficiently justified retention of J.H. Campbell as a capacity resource (which it does not for the reasons outlined above), it would not follow that J.H. Campbell's electric *energy* is needed to address the identified emergency. Given the nature of the alleged emergency identified in the Order, no dispatch from J.H. Campbell should be necessary unless and until called upon by MISO expressly to address an emergency purpose.

iii. "Economic dispatch" is not in the public interest in this case

Section 202(c) also requires that DOE determine that a given remedy is in the public interest.[144] The public interest determination is not an independent or sufficient criteria to order any particular action. Rather, Congress's use of the conjunctive "and" in section 202(c)(1) clearly prohibits DOE from ordering actions that the Department believes will advance the public interest if those actions exceed what is needed to address the identified emergency. In fact, DOE acknowledged this limit on its authority in its order denying rehearing of its order directing the retention of the Yorktown power plant.[145] Therefore, for the reasons explained above, economic dispatch is not appropriate even *if* DOE determines that it would advance the public interest.

However, DOE's vague direction to MISO to operate Campbell using "economic dispatch" will not further the public interest. DOE's order does not explain why it

[144] 16 USC § 824a (c)(1).
[145] DOE Order 202-18-1 at 4.

believes economic dispatch would be in the public interest, other than a general reference to "minimize[ing] cost to ratepayers." However, this justification fails for two reasons. First, the Order's reference to economic dispatch is ambiguous and leaves open the likelihood that Consumers will operate the facility even at times when its operation will have the effect of *increasing* costs to consumers. For example, Consumers is likely to commit J.H. Campbell into MISO's day ahead electricity market as a "must run" unit, rather than using Emergency commitment.[146] In other words, Consumers will operate the units at least at minimum load every day rather than when there is a forecasted shortfall (e.g., due to unexpected load, unit outage, or a natural disaster). In such circumstances, J.H. Campbell will run at its minimum operational level regardless of whether doing so is truly economic. As a result, DOE has not justified, and cannot be reasonably certain, that economic dispatch will "minimize cost to ratepayers" — its sole explanation for the operational profile it has directed MISO to adopt. In other words, DOE's ordering of economic dispatch in this case is arbitrary.

Moreover, by directing economic dispatch, rather than reserving J.H. Campbell for discrete supply shortages by committing it as Emergency status, DOE's order will result in the facility operating significantly more than necessary. Because J.H. Campbell is old, and because Consumers has been deferring maintenance in anticipation of its retirement, a significant step-up in operation caused by must-run commitment and economic dispatch will increase the likelihood that one or more

[146] *See* MISO Tariff, Section 39.2.5.b.xxvi (discussing Emergency Commitment Status).

units break, requiring costly maintenance to continue operating. Such repairs would likely further increase costs to ratepayers—costs that would be less likely to occur under an operational order better tailored to the emergency that DOE has identified. For example, DOE could have minimized the risk of ratepayer costs had it directed Consumers and MISO to commit (and ultimately dispatch) the facility only after analysis showing a likely near-term supply/demand imbalance or short-term emergency conditions (such as a heatwave, or the forced outage of a large generator or transmission line). The Order is arbitrary and capricious by ordering operation that risks increasing costs to ratepayers, the very outcome DOE has said it is looking to avoid.

Second, the Order fails to consider, let alone explain away, the fact that the State of Michigan has made an independent judgment that it would be in the best interest of ratepayers, the state, and the environment, to accept Consumers' proposal to retire J.H. Campbell. As explained above, the State of Michigan and MISO each went through robust processes to assess the need for J.H. Campbell (or lack thereof), as well as the economic and environmental impacts of its continued operation. The State of Michigan appears not to have been consulted on DOE's Order, notwithstanding the extensive process that it underwent to evaluate whether retirement would be in the public interest. Here, the public interest is best effectuated by respecting the Michigan's considered decision to approve the closure of J.H. Campbell plant, rather than to allow its near continuous operation at ratepayer expense.

Finally, for the reasons explained more fully below, the Order fails to consider the increased air and water pollution that will be caused by J.H. Campbell operating pursuant to economic dispatch instructions. DOE fails to even consider these harms, let alone weigh them against the (alleged) benefits of increased operation, in its determination that economic dispatch of the J.H. Campbell plant will further the public interest.

E. The Department failed to limit its remedy as required by 202(c)(2).

Section 202(c) imposes strict substantive limits on the Department's authority to issue emergency orders that may result in conflicts with any Federal, State, or local environmental law or regulation. Congress deliberately included these limitations to prevent section 202(c) from becoming a de facto exemption from environmental regulation. Here, DOE failed to comply with either of the statute's two express constraints and therefore acted unlawfully.

i. Section 202(c)(2) contains two distinct and binding legal constraints

Congress imposed two critical limitations on the scope of a DOE emergency order under section 202(c):

Temporal Constraint. First, DOE must "ensure that such order requires generation . . . of electric energy only during hours necessary to meet the emergency and serve the public interest."[147] Again, this is a conjunctive requirement such that both conditions—operation in a given hour must be necessary to meet the emergency

[147] 16 U.S.C. § 824a(c)(2).

and operation in a given hour must serve the public interest—must be satisfied.[148] Moreover, by referring to the "hours" necessary to meet the emergency, Congress placed a high burden on DOE to demonstrate that the remedy provided was narrowly tailored to the specifics of the emergency that the order is designed to address.

Environmental Constraint. Second, the Department must "ensure that such order . . ., to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts."[149]

The Department acknowledges that, "additional generation may result in a conflict with environmental standards and requirements" and so it is required to limit additional generation from J.H. Campbell. However, the Order then wholly fails to meet the acknowledged temporal and environmental constraints in the particular ordering conditions that it establishes.

ii. The Order violates Section 202(c)(2)'s temporal constraint

The Order states that its direction to Campbell is "limited in duration to align with the emergency circumstances."[150] But, in fact, DOE has directed the unit to operate for the entire statutory maximum of 90 days. And, as described in more detail *supra,* within that 90-day window, DOE has directed the use of "economic dispatch"—an operational direction that will likely result in Campbell operating at least at its

[148] DOE Order No. 202-18-1, 4(Nov. 6, 2017).
[149] 16 U.S.C. § 824a(c)(2).
[150] Order at 2.

minimum output level, and more likely at the maximum output Consumers Energy can manage, taking into account the state of the facility, continuously for the 90-day period—without providing any other temporal limitation on operations. In other words, the Order appears to assume, without explanation, that an emergency will exist in every hour over the entire 90-day period of the Order that Consumers happens to submit a bid into MISO's energy auction that is lower than the market-clearing price.[151] There is no reason to expect that this will actually be the case.

For these and all the reasons explained in section IV.C, the Order's direction that MISO dispatch J.H. Campbell economically is flatly inconsistent with section 202(c)'s requirement that emergency orders be limited to "only" those "hours" in which operation is necessary to meet the emergency. DOE cannot transform an hour-by-hour limitation into a blanket summer-season waiver through hand-waving at "elevated risk" of tight operating reserves and "*potential* electricity shortfalls."

DOE's failure to limit dispatch to discrete periods when the generation is needed to address the purported emergency renders the Order unlawful under the plain terms of § 202(c).

iii. The Order violates section 202(c)(2)'s environmental constraint

Section 202(c)(2) also requires DOE to ensure, "to the maximum extent practicable," that its orders (1) are consistent with applicable environmental laws and

[151] In fact, it is not clear that DOE will limit operation to 90 days. DOE is authorized to extend the Order beyond 90 days under section 202(c), 16 U.S.C. § 824a(c)(4)(A), and has made no representation that the "emergency" is likely to be resolved by the end of the 90-day period.

regulations and (2) "minimize any adverse environmental impacts." The Department makes no serious effort to comply with this mandate.

First, the Order contains no analysis of J.H. Campbell's environmental obligations. J.H. Campbell is subject to air pollution requirements limiting its emissions of SO_2, NO_x, particulate matter, and mercury, and mandates the use of pollution control equipment such as baghouses, dry sorbent injection, and activated carbon injection systems.[152] DOE does not reference these requirements, direct Consumers to optimize the use of pollution controls or avoid operation during air quality episodes (even if those episodes occur at a time when the marginal energy from J.H. Campbell is not needed to meet electric demand), or provide any guidance for how Consumers is to operate the facility in the event that these requirements would come in conflict with its ability to provide power at any given time. It does not clarify what steps Consumers Energy would have to take to ensure continued operation of pollution control equipment in the event such equipment malfunctioned during the 90-day period. Nor does it appear the Department consulted with the State of Michigan, including its environmental regulator, to identify mechanisms to allow J.H. Campbell to remain available in a way that would minimize conflicts with state environmental laws, which the State was uniquely positioned to advise on and which

[152] *See* Michigan Department of Environment, Great Lakes, and Energy, Renewable Operating Permit Issued to Consumers Energy, J.H. Campbell Generating Complex [J.H. Campbell ROP] (July 2, 2021), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal, and also accessible at https://www.egle.state.mi.us/aps/downloads/rop/pub_ntce/B2835/B2835%20FINAL%2007-01-21.pdf.

is required by section 103 of the Department of Energy Organization Act.[153] Instead, the Order offers only generic language about "compliance with applicable requirements… to the maximum extent feasible."

Second, the Order does not establish any operational criteria to "minimize any adverse environmental impacts" as required by section 202(c)(2). This requirement is in addition to the direction to minimize conflicts between operations and environmental requirements. It makes clear that Congress intended DOE to go beyond just avoiding regulatory conflicts but to proactively consider the environmental impact of its emergency orders. But DOE did not design its order to minimize environmental impacts of continued operation of J.H. Campbell. In fact, DOE's order runs directly contrary to the objective of minimizing environmental impacts by expressly directing MISO to operate J.H. Campbell on an "economic dispatch" basis. That instruction prioritizes low-cost dispatch irrespective of environmental impact.

F. The Order Violates NEPA.

Orders issued under section 202(c) are major federal actions subject to NEPA.[154] Such orders direct federal interventions that may affect environmental conditions. The direction to continue operation of J.H. Campbell is unquestionably a major action that significantly affects the environment. Continued operation of J.H. Campbell will result in significant increases of air and water pollution compared to a

[153] *See* 42 U.S.C. § 7113.
[154] 42 U.S.C. § 4336e(10) (defining a "major federal action" as one in which the agency carrying out such action determines subject to substantial Federal control and responsibility.").

scenario in which Campbell retired as planned.[155] In fact, the Order directly concedes this point, stating "the additional generation may result in a conflict with environmental standards and requirements."[156]

For any DOE action affecting the quality of the environment, DOE must comply with NEPA—including through issuance of an environmental impact statement, environmental assessment, categorical exclusion, or special environmental analysis.[157] DOE has not taken, or even initiated, any such action. As such, it is acting contrary to its own NEPA regulations and to its obligations under NEPA.

DOE has previously sought to comply with NEPA for section 202(c) orders through categorical exclusions or special environmental assessments. Neither have been undertaken in this instance. Moreover, neither would be applicable here.

DOE has previously pointed to categorical exclusion B4.4 for "power management activities." However, that categorical exclusion is applicable only "provided that the operations of generating projects would remain within normal operating limits." Here, the Order explicitly authorizes the J.H. Campbell plant to operate beyond its normal permitted limits. Consequently, neither categorical exclusion B4.4, nor any other available exclusion, applies.

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[155] *See* J.H. Campbell ROP, *supra* n. 152; State of Michigan Department of Environmental Quality, Authorization to Discharge Under the National Pollutant Discharge Elimination System, Permit No. MI0001422 (May 29, 2018), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal.
[156] Order at 2.
[157] *See* 10 C.F.R. § 1021.102(b).

More recently, DOE has, on certain occasions, relied on emergency provisions that can excuse agencies from preparing environmental documents before taking such actions,[158] and instead prepared after-the-fact Special Environmental Analyses in the event that an order results in a significant effect on the environment.[159] However, these instances involved sudden emergencies that provided DOE substantially less notice compared to the months or years of advance warning DOE received regarding J.H Campbell's scheduled retirement. In this case, DOE acted in response to circumstances known well in advance: the long-scheduled retirement of J.H. Campbell on May 31, 2025. Given considerable lead time, DOE had ample opportunity to prepare, at a minimum, an EA prior to issuing its Order. DOE's failure to initiate any environmental review thus lacks justification.

Moreover, there will be even less justification for a failure to initiate appropriate environmental review for any extension of the Order beyond the initial 90 days. Under section 202(c)(3), orders conflicting with environmental laws are strictly limited to 90 days but may be extended. However, such extension requires consultation with other federal agencies responsible for regulating or with expertise in such environmental impacts.[160] Any justification that NEPA can be sidestepped to

[158] *See* 10 C.F.R. § 1021.343(a); 40 C.F.R. § 1506.12.
[159] *See* DOE, Air Quality and Environmental Justice Memorandum (2021), https://www.energy.gov/sites/default/files/2022-01/sea-05-ercot-air-quality-and-ej-analysis-2021-07-21.pdf; DOE, Special Environmental Analysis for Actions Taken Under U.S Department of Energy Emergency Orders Regarding Operation of the Potomac River Generating Station in Alexandria Virginia (2006), https://www.energy.gov/sites/default/files/nepapub/nepa_documents/RedDont/SEA-04-2006.pdf
[160] 16 U.S.C. § 824a(c)(4)(B).

address an emergency need fades as DOE's orders extend beyond the initial 90-day period.

V. CONCLUSION

For the foregoing reasons, the Michigan Attorney General's request for rehearing should be granted.

Dana Nessel
Michigan Attorney General

Michael E. Moody

Digitally signed by Michael E. Moody
Date: 2025.06.18 16:14:42 -04'00'

Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

Dated: June 18, 2025

Attachment A

2025 NERC Summer Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025

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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is spans six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA*), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA*. Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's 2024 *State of Reliability* report

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

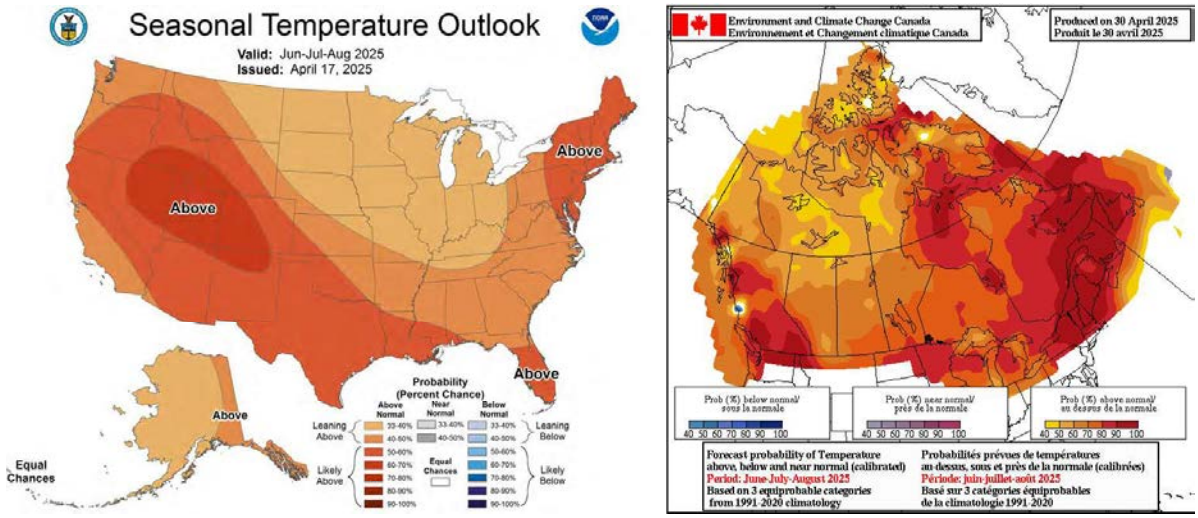


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 1.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 2.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

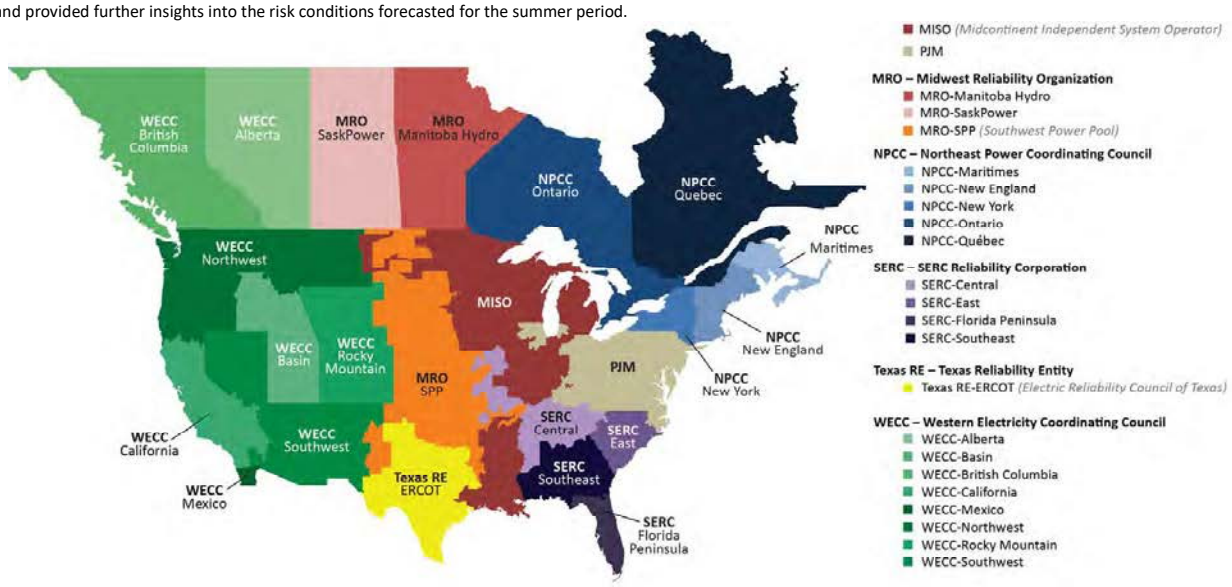
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central SERC-East SERC-Florida Peninsula SERC-Southeast	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



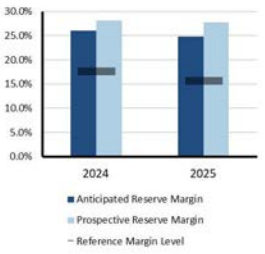
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

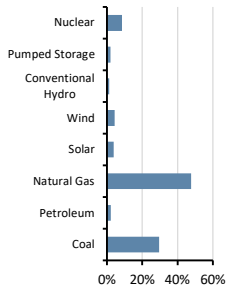
On-Peak Reserve Margin



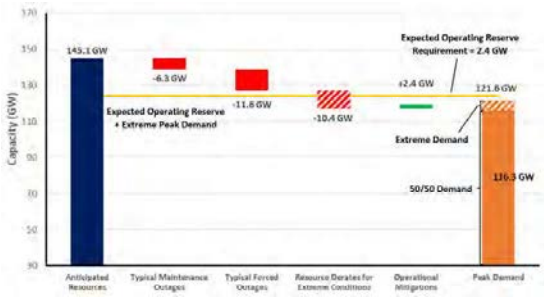
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions

MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

Highlights

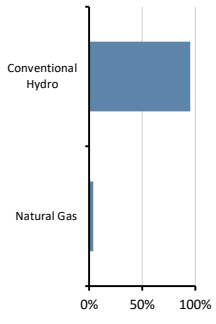
- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

Risk Scenario Summary

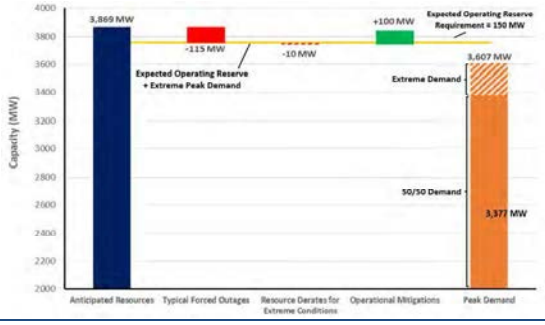
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

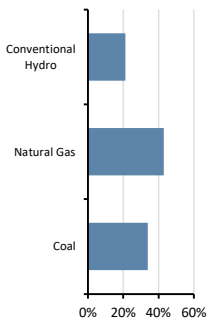
- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

Risk Scenario Summary

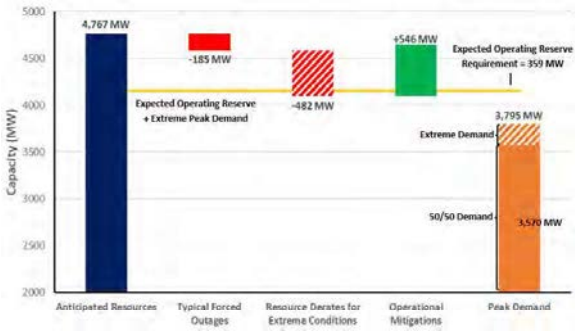
Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice

MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Highlights

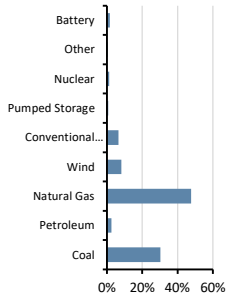
- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

Risk Scenario Summary

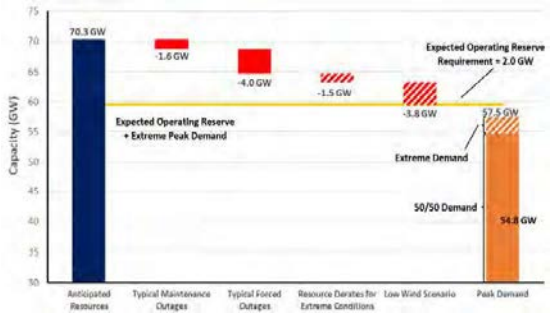
Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

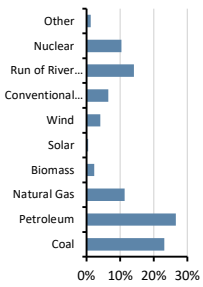
- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

Risk Scenario Summary

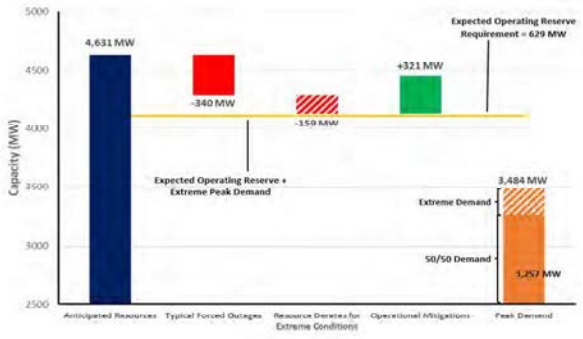
Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)

NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

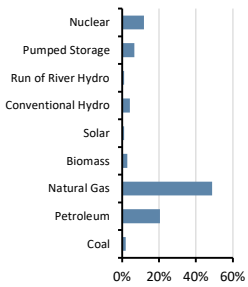
- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

On-Peak Reserve Margin

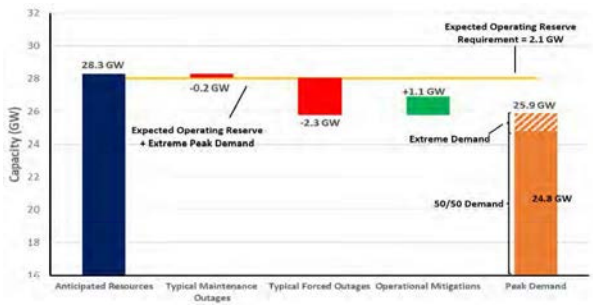
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

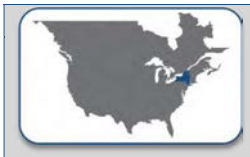
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

Highlights

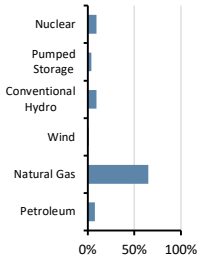
- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

Risk Scenario Summary

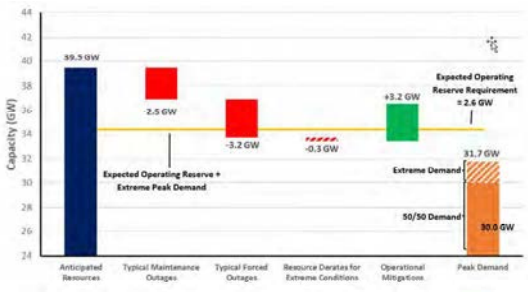
Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual

NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

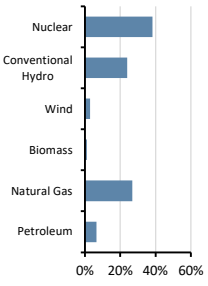
- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

Risk Scenario Summary

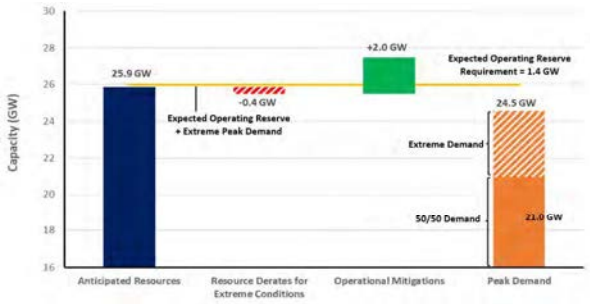
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.

NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

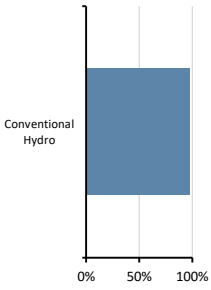
- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

Risk Scenario Summary

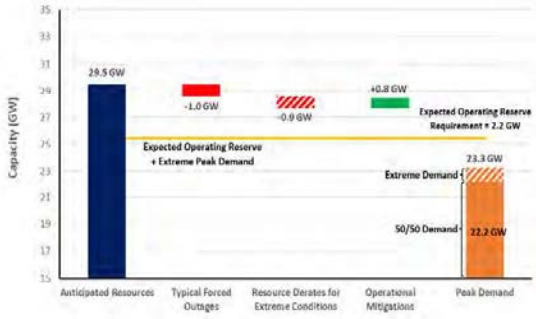
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.

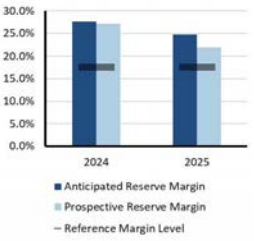
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

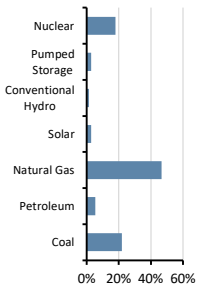
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

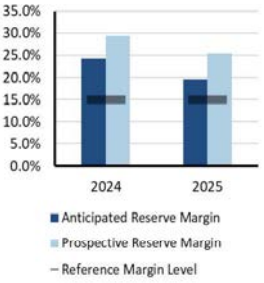
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

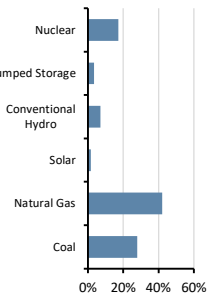
On-Peak Reserve Margin



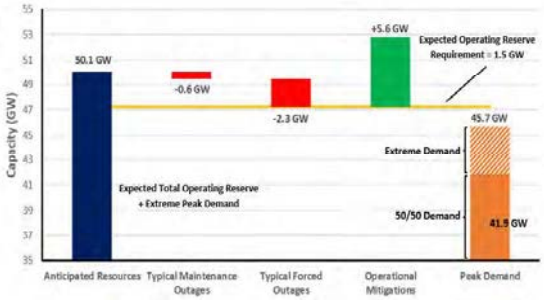
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures

SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

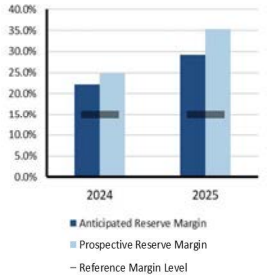
Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

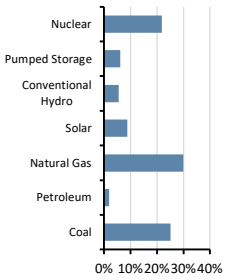
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures

SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

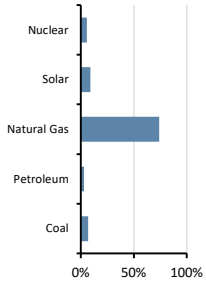
- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

On-Peak Reserve Margin

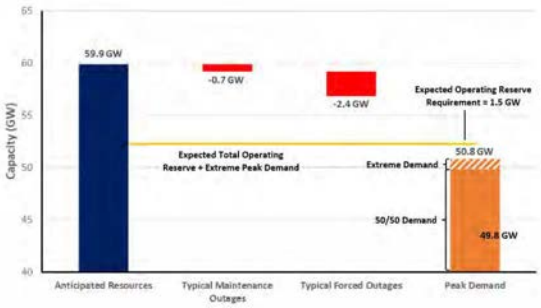
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

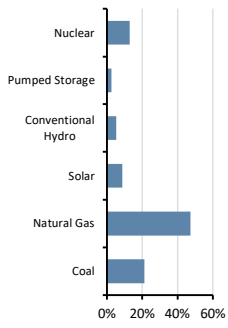
- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

On-Peak Reserve Margin

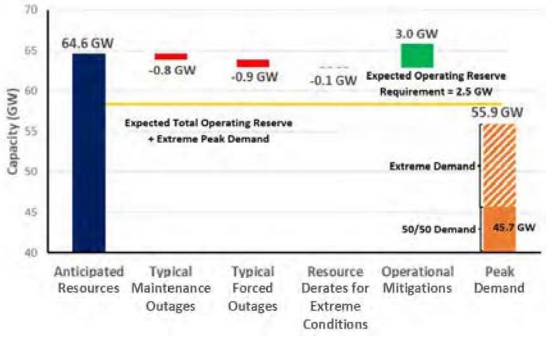
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

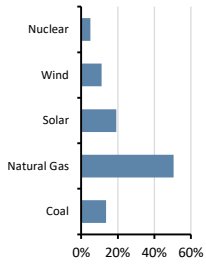
- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

Risk Scenario Summary

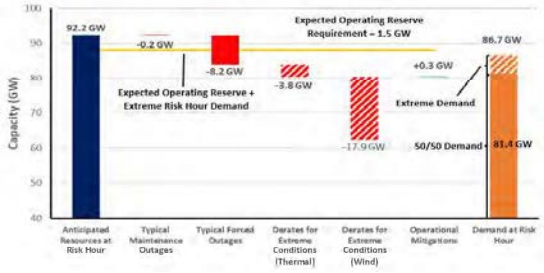
Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports

WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

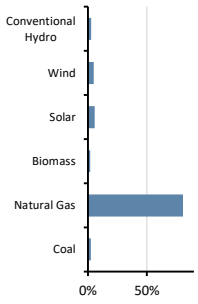
- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

Risk Scenario Summary

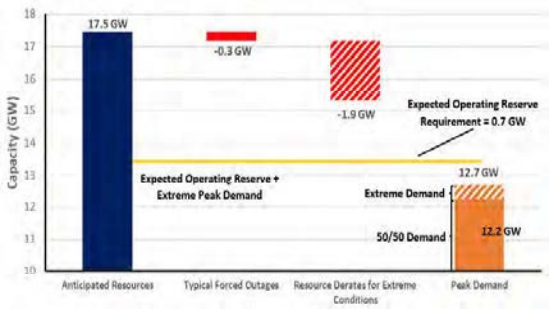
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

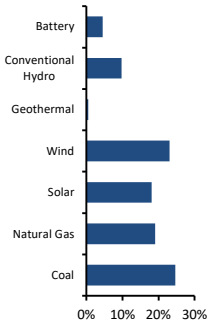
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios with imports.

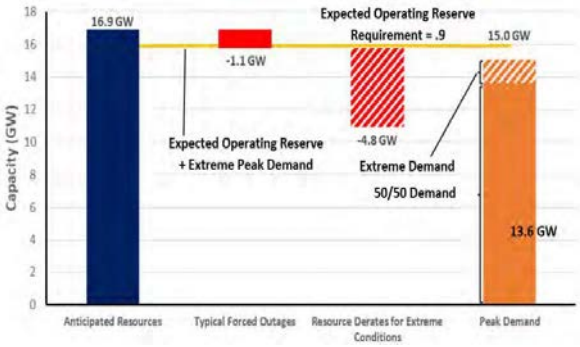
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

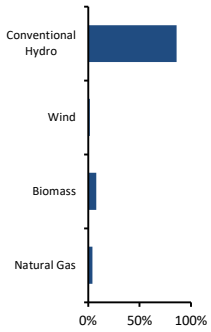
- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

Risk Scenario Summary

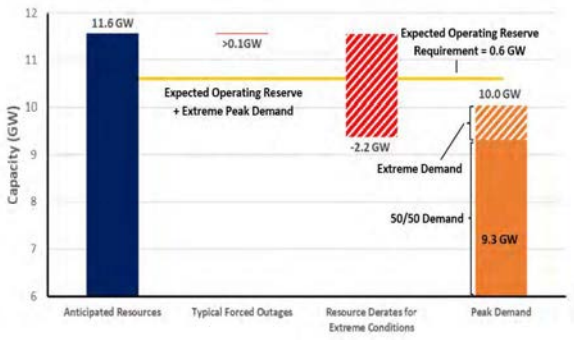
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-California

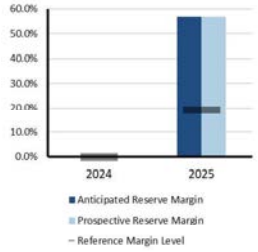
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

On-Peak Reserve Margin

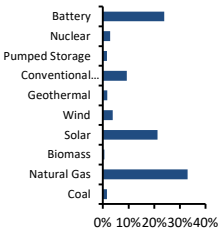
(Note: year comparison not available)



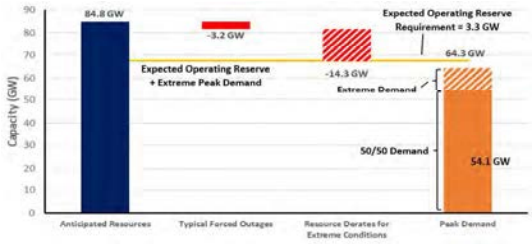
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages

WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

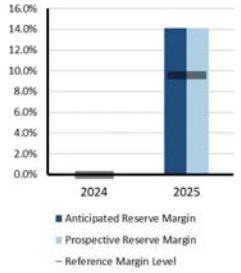
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

Risk Scenario Summary

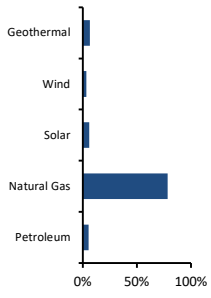
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

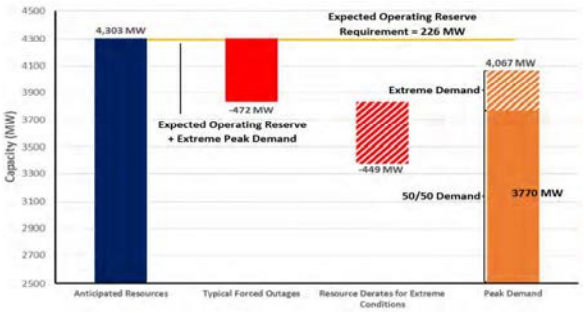
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

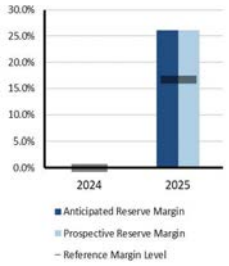
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

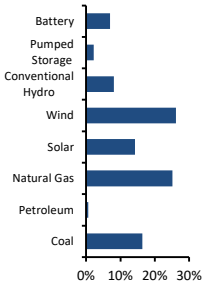
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

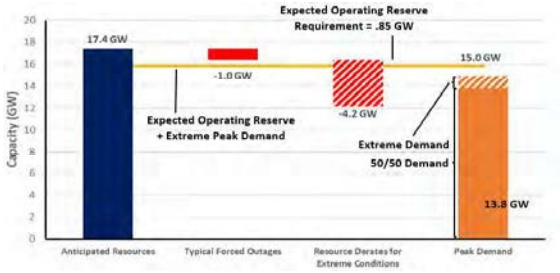


(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA*.

Highlights

- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

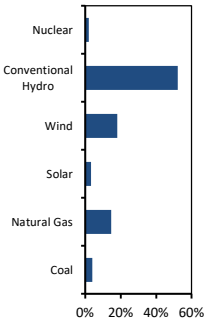
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

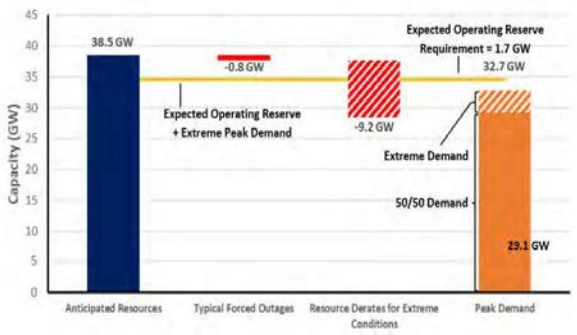
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

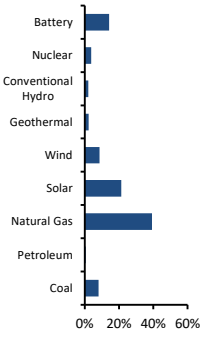
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

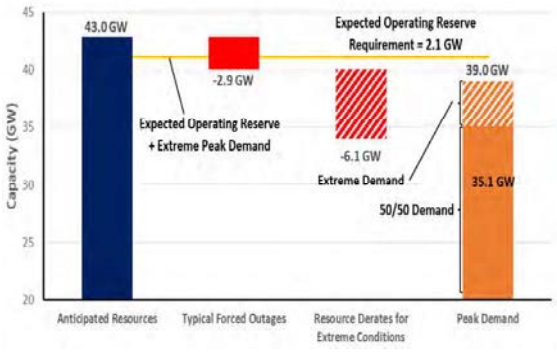
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[12] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[13] The summer season represents June–September and the winter season represents December–February.

[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the summer 2025 as shown in **Figure 4**.

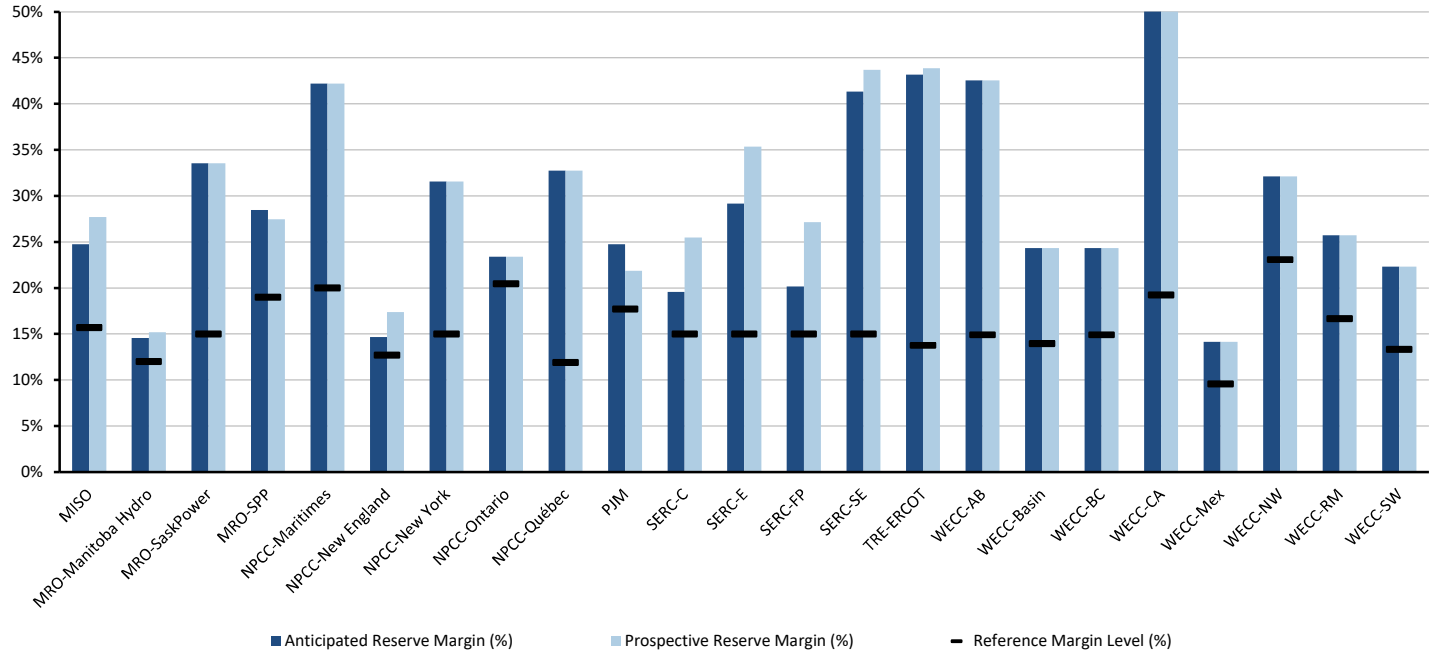


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

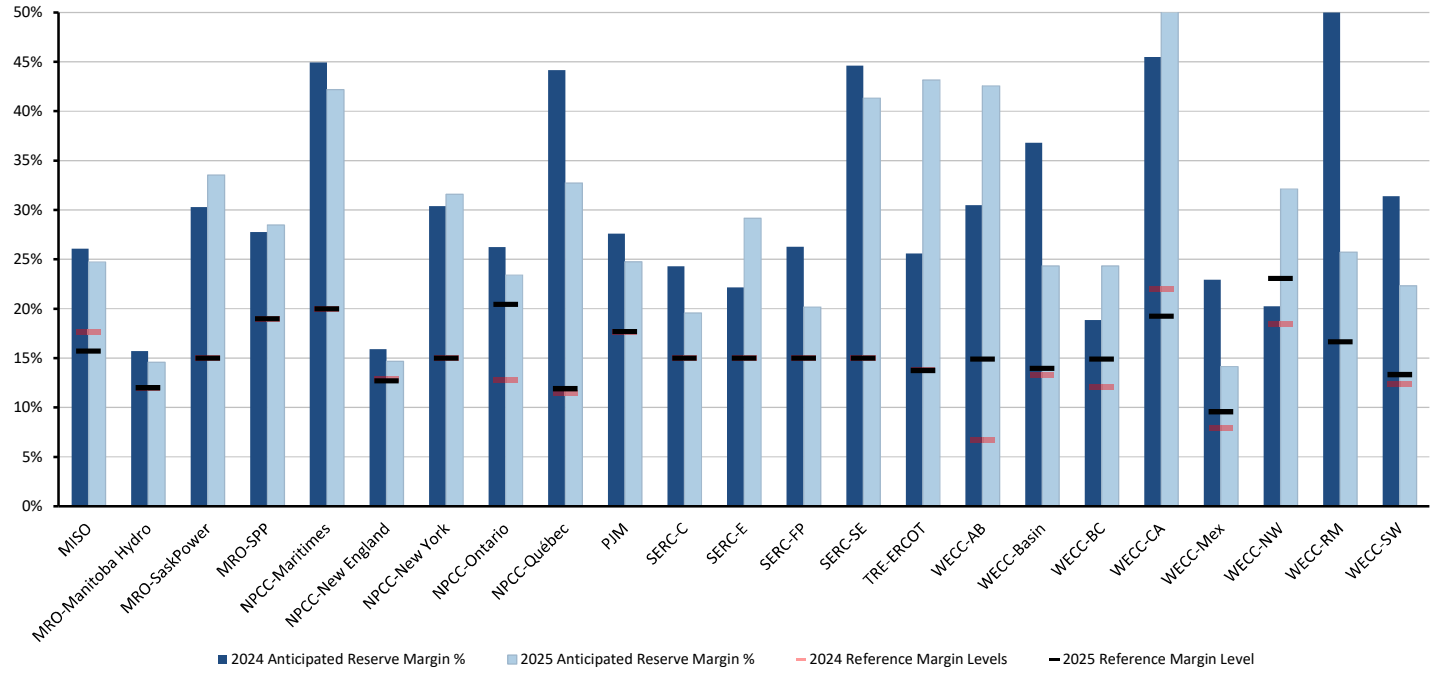


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

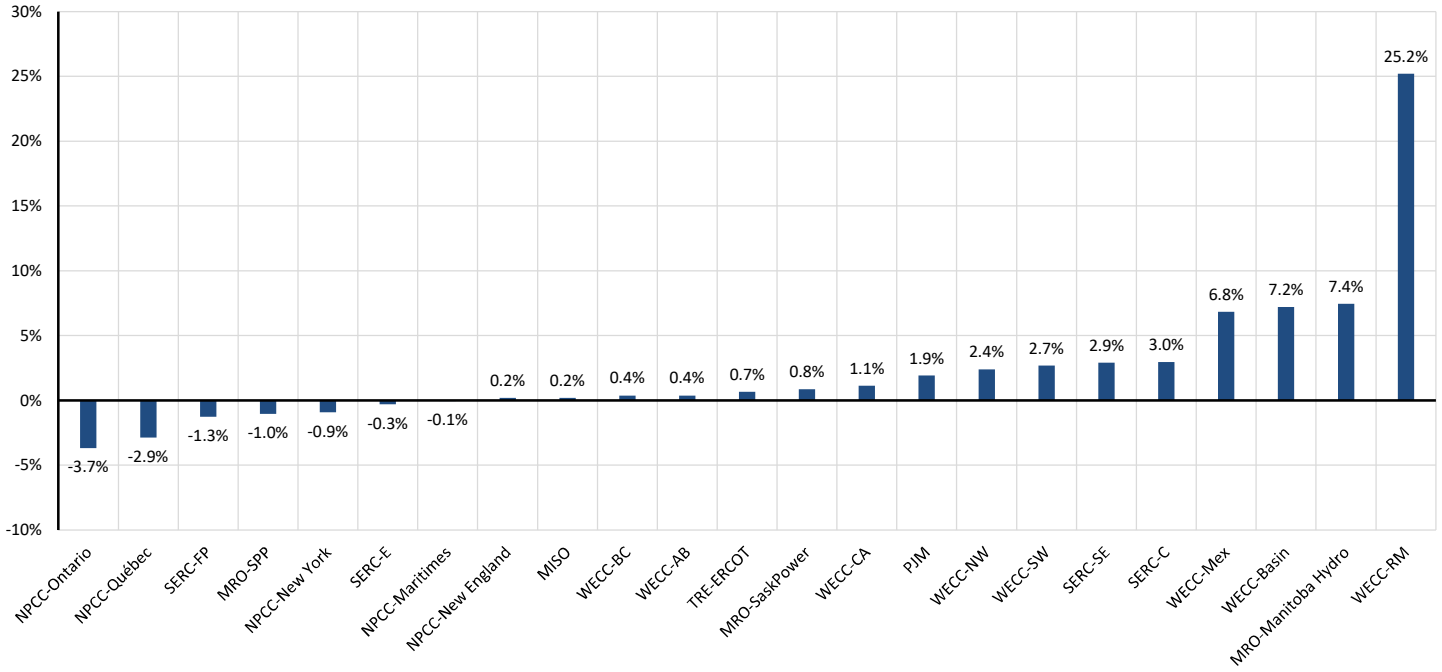


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	175,081	34,774	20%	142,014	86,170	61%	101,959	65,290	64%	36,311	32,298	89%

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta's demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.
[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2024 SRA*.
[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.
*Values include both maintenance and forced outages.
**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Attachment B

MISO 2025 PRA Report

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…

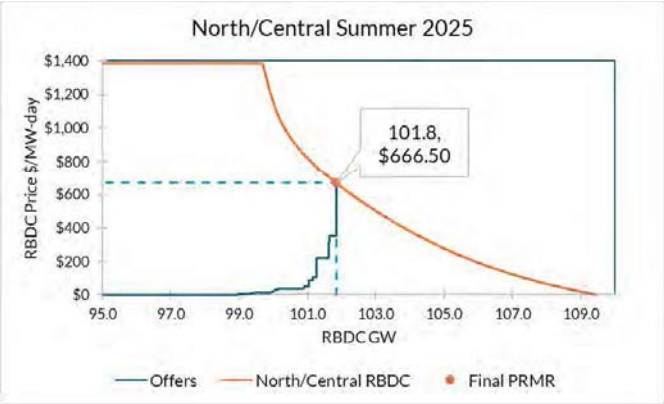
- Delivers competitive prices aligned with seasonal risks and tightening surplus
  - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
  - Clears capacity above target Planning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

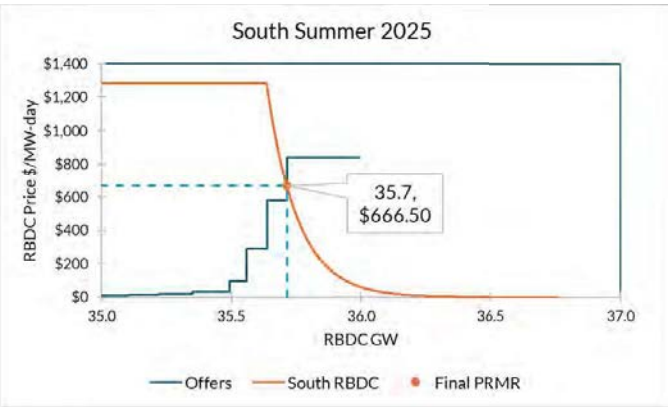
Why it Matters

- 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

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

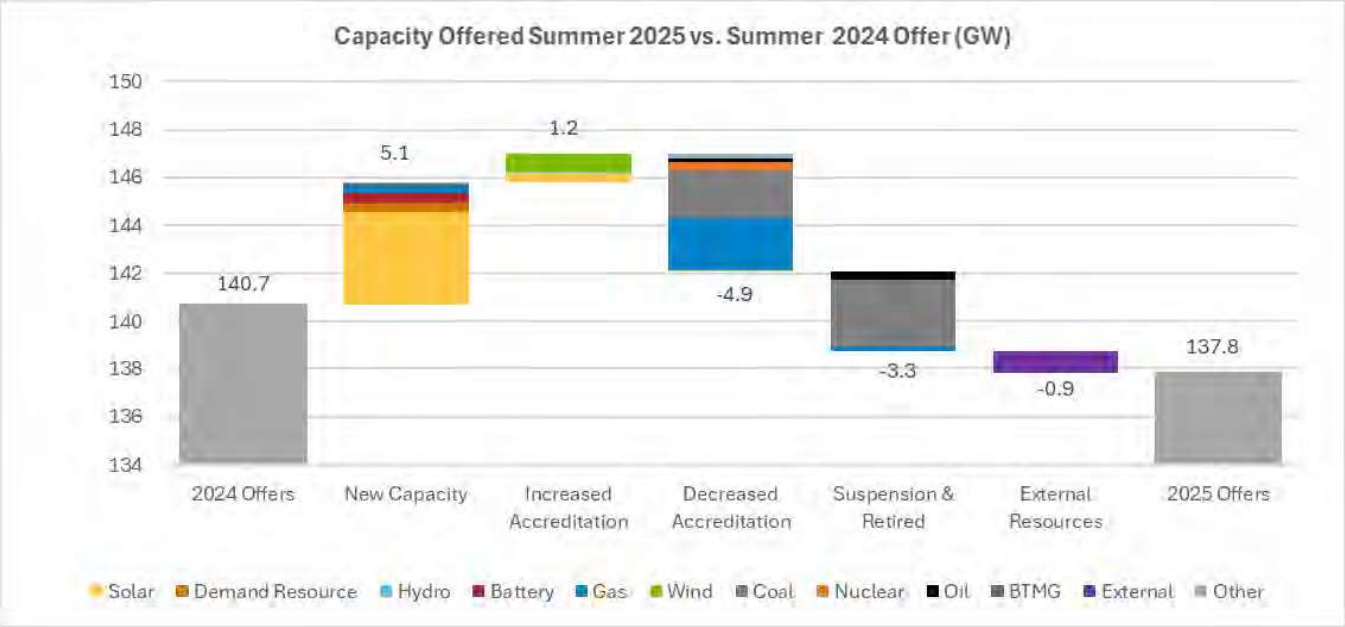
- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

	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

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

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

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

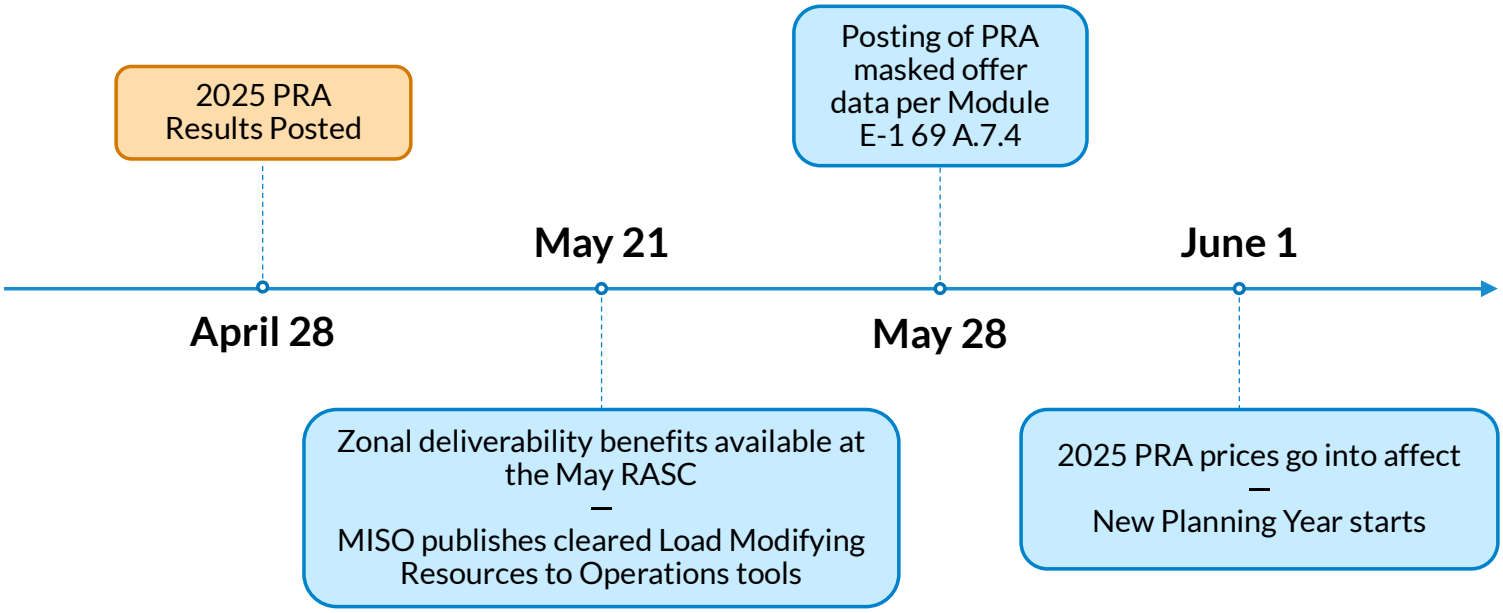
- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025)*
- ✓ Approved over $30 billion in new transmission 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

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

Next Steps


2025 PRA Results Posted
Posting of PRA masked offer data per Module E-1 69 A.7.4
April 28
May 21
May 28
June 1
Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools
2025 PRA prices go into affect
—
New Planning Year starts

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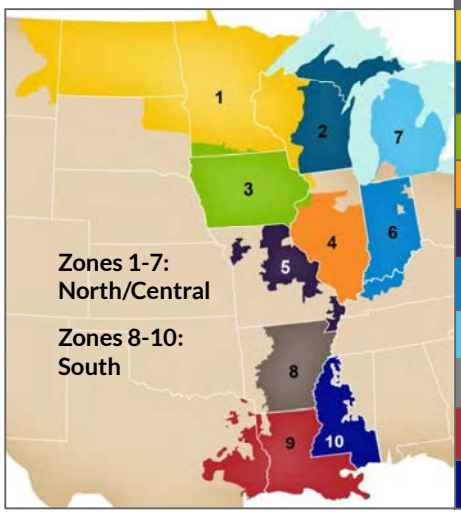
Acronyms

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

2025 PRA Results

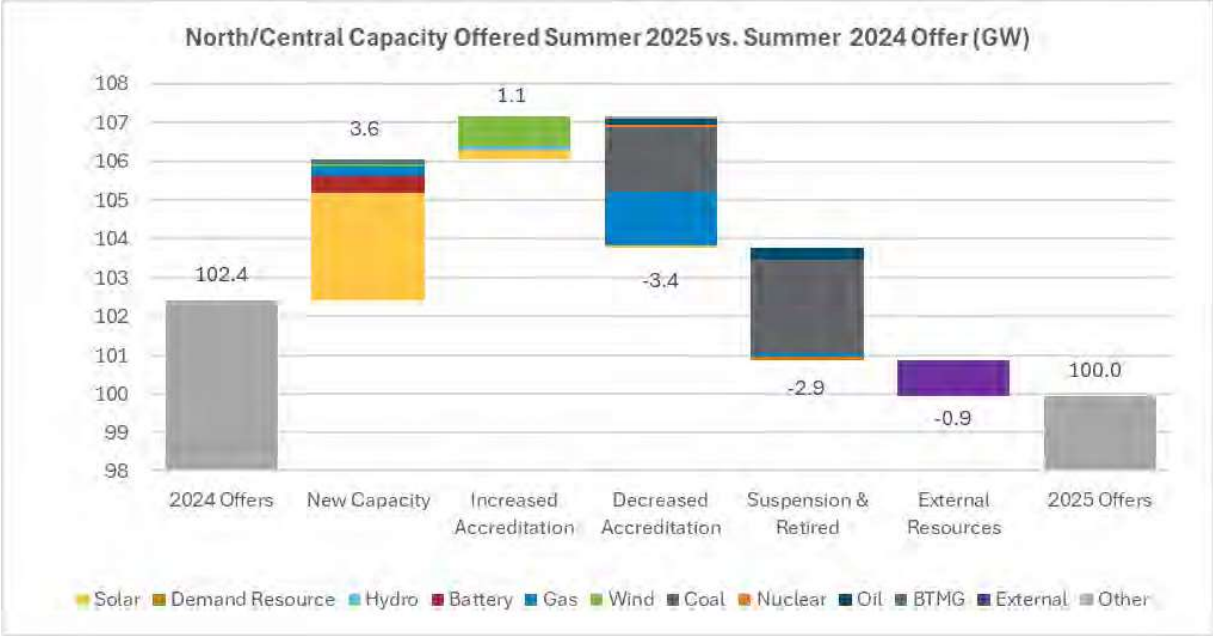
MISO Resource Adequacy Zones



	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	$666.50	$91.60	$33.20	$69.88
2				
3				
4				
5				
6				
7				
8		$74.09		
9				
10				

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

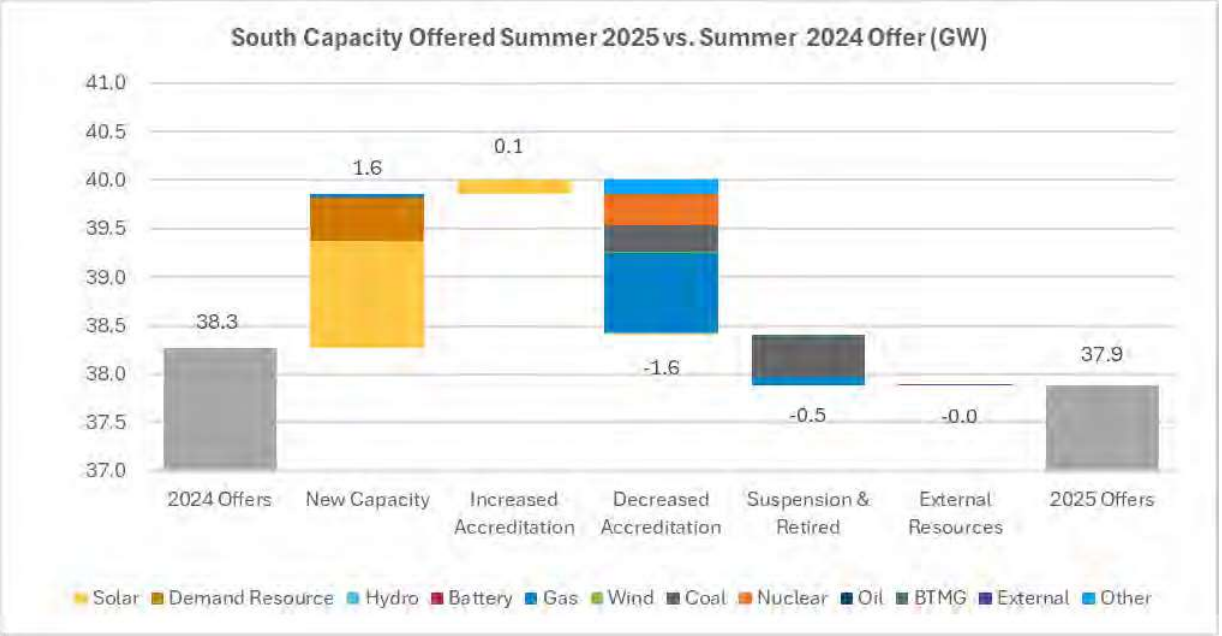
For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



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

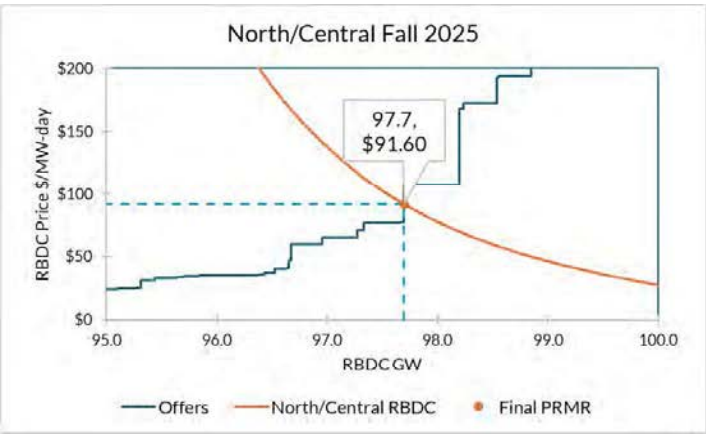
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

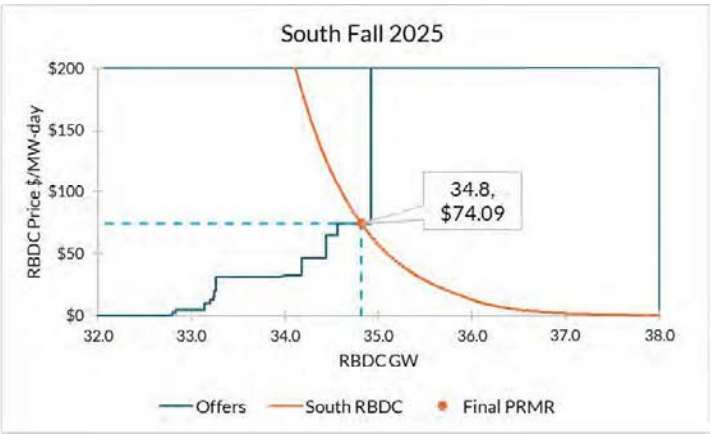
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



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

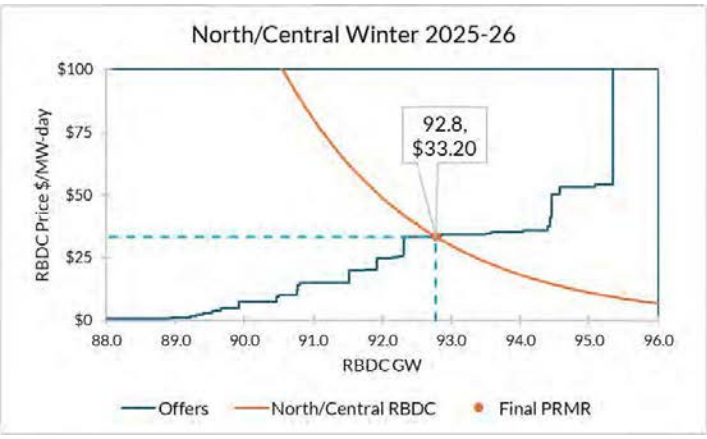
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

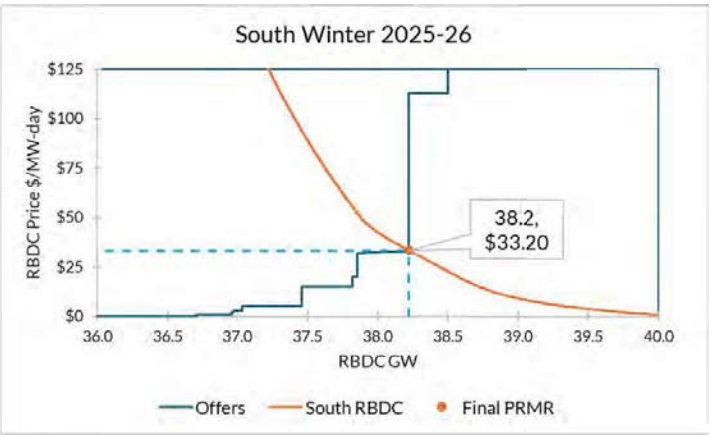




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
  - ACP for North subregion is $91.60, and $74.09 South subregion
  - A marginal 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%

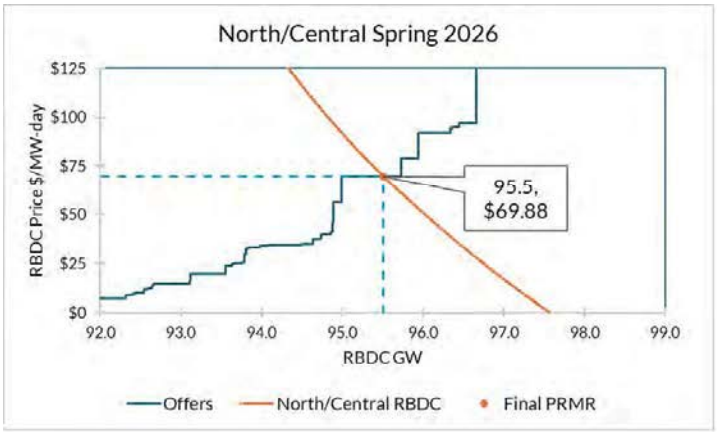
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices





- 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

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

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

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

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

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

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

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

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

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

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
Fall 2025	$91.60							$74.09			$83.24-$91.60

- 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

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

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

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

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

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

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

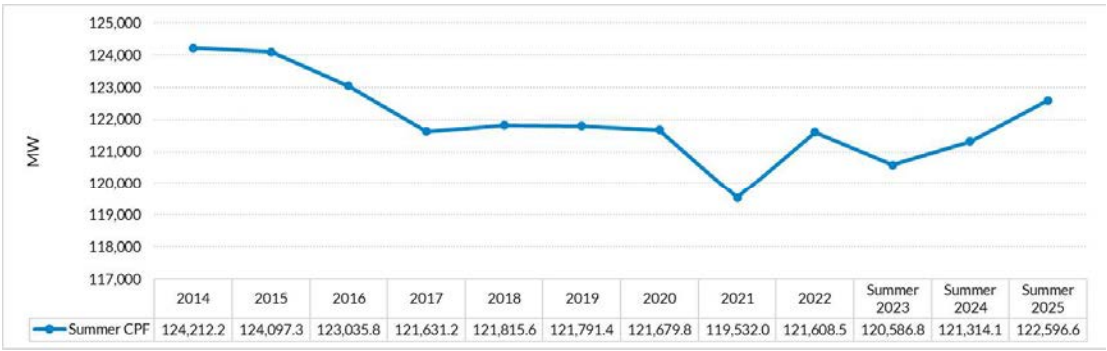
2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)

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

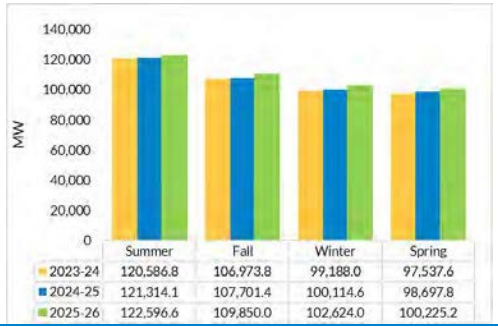
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

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

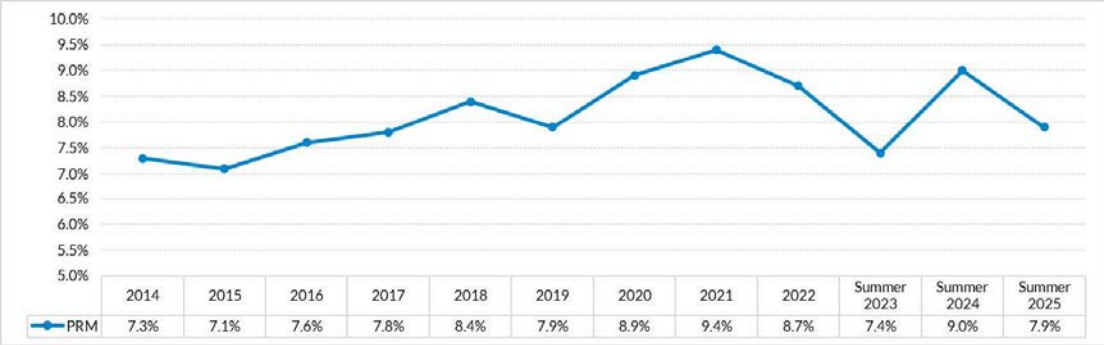


	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

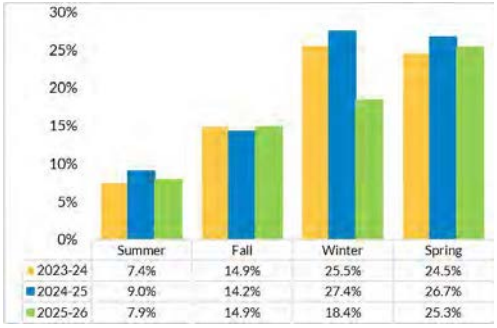
PRMR: Planning Reserve Margin Requirement

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

Planning Reserve Margin (%)

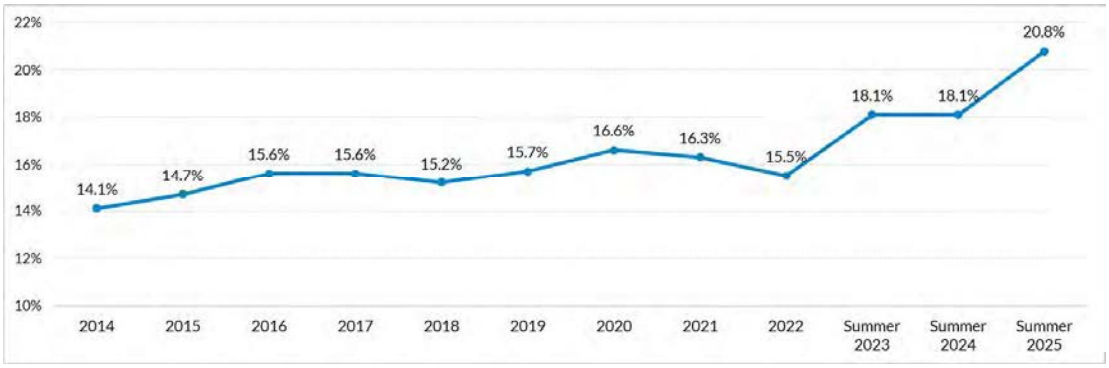


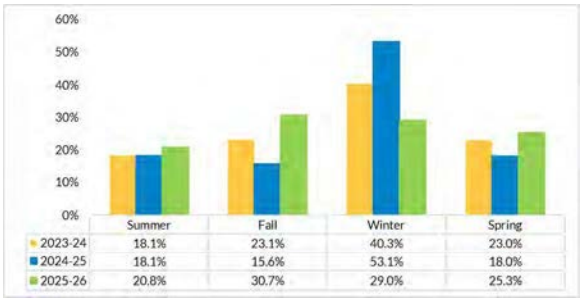
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	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 (%)





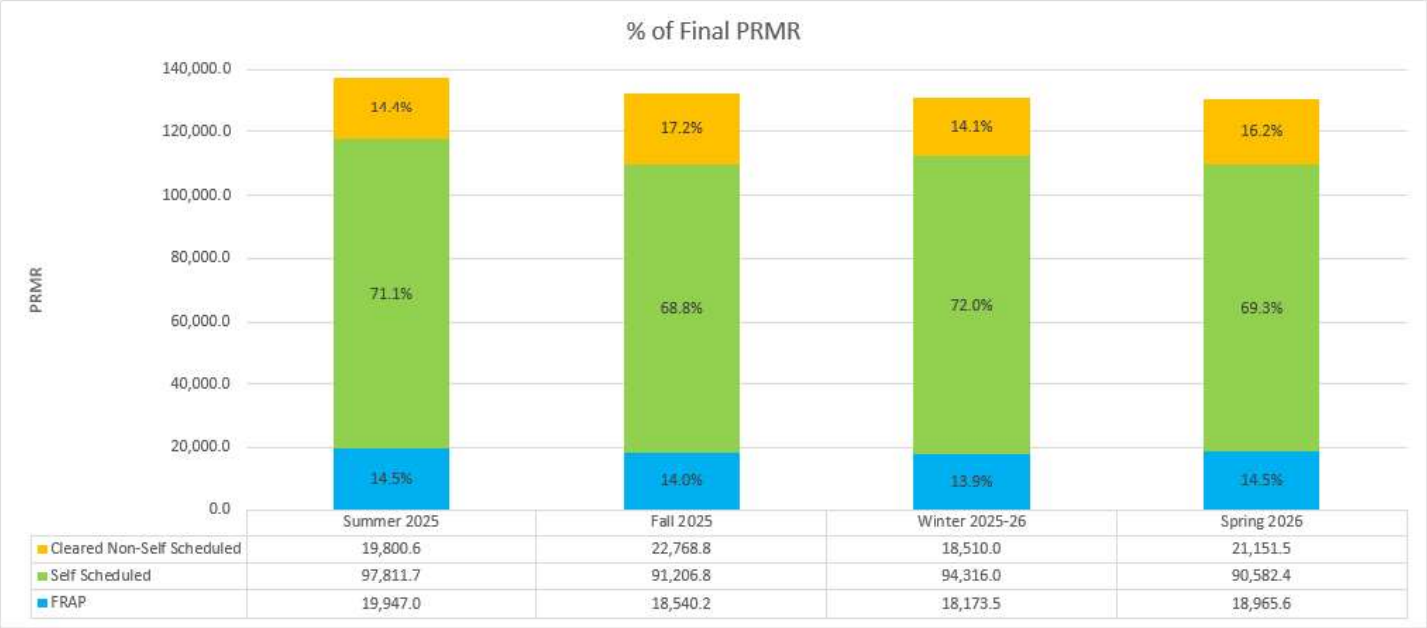
	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%
2025-26	20.8%	30.7%	29.0%	25.3%

- 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

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

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

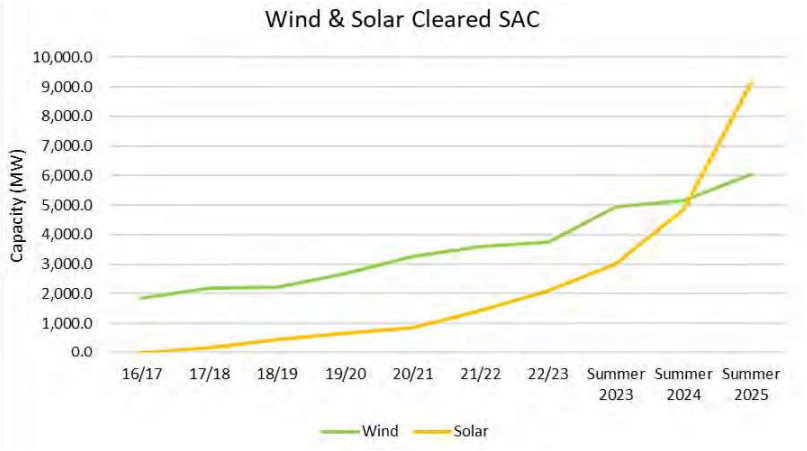


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

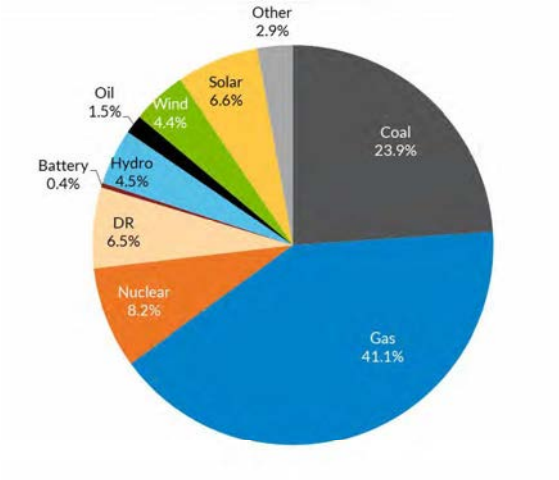
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 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

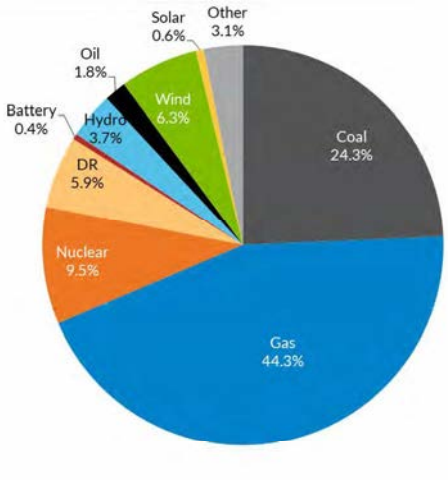
Summer 2025



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

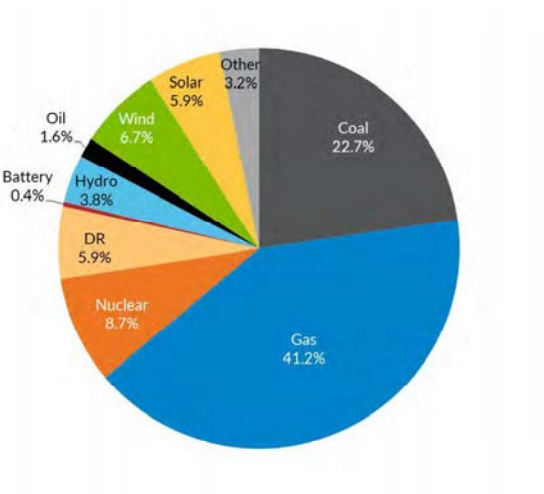


PRMR: Planning Reserve Margin Requirement

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

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

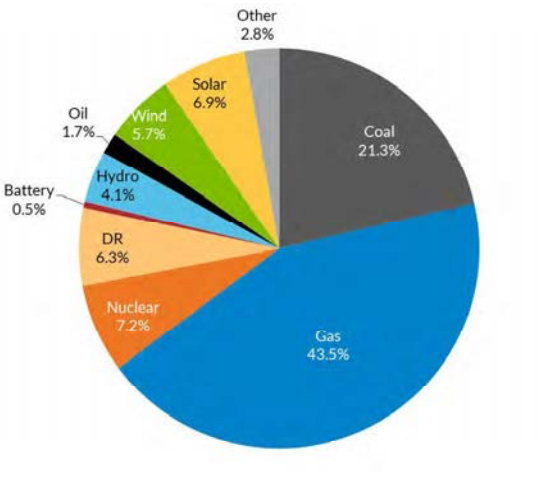
Fall 2025



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

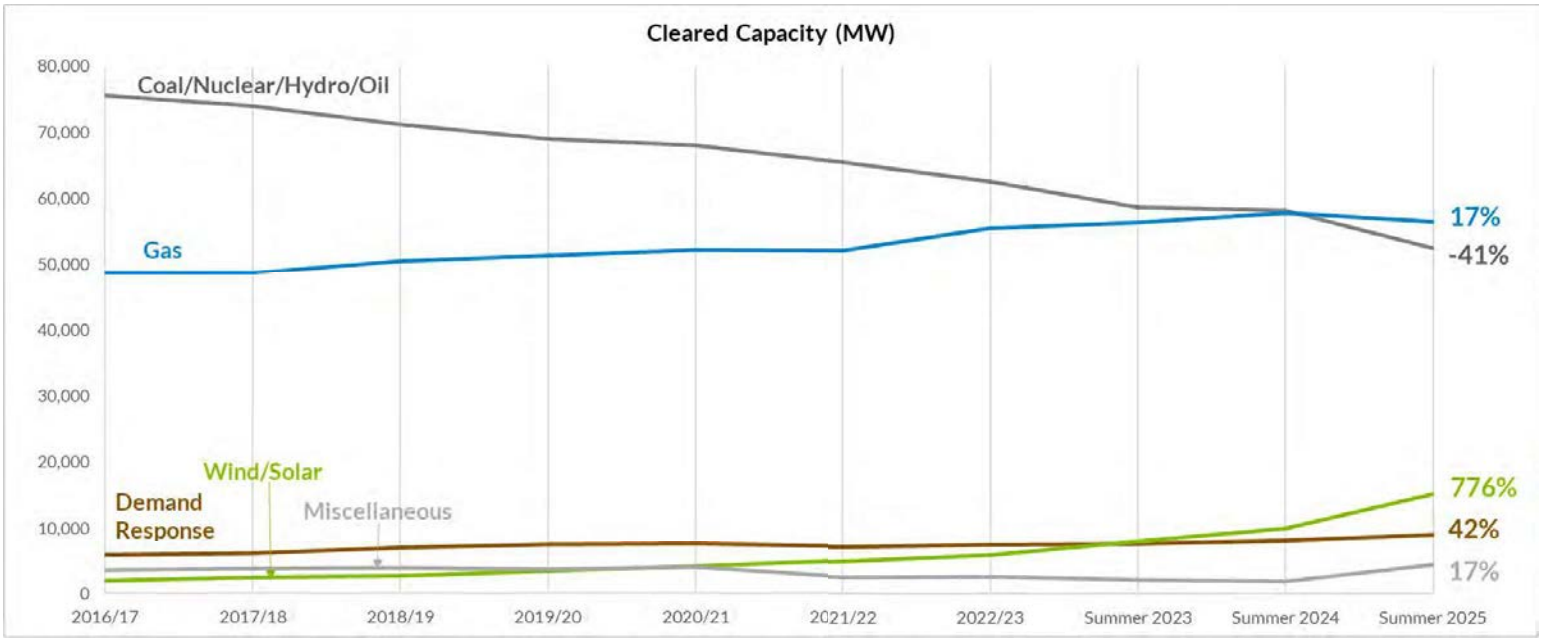
Spring 2026



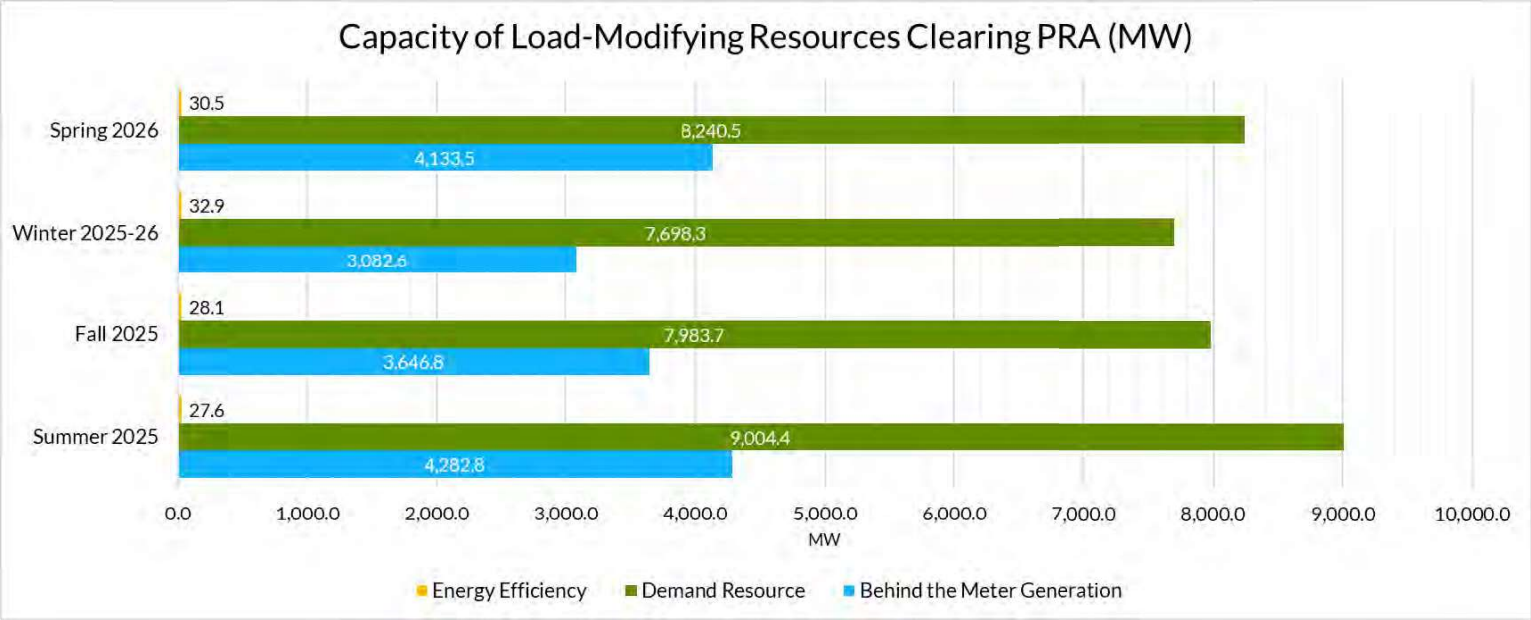
PRMR: Planning Reserve Margin Requirement

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

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/

Attachment C

Collection of MISO Attachment Y materials

Consumers Energy
Count on Us®

A CMS Energy Company

Timothy J. Sparks, P.E.
Vice President Electric Grid Integration

VIA Electronic Mail

December 14,2021

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

Re: Suspension of Campbell Units 1, 2 & 3

Dear Mr. Witmeier:

Consumers Energy Company ("Company") hereby provides notice to the Midcontinent Independent System Operator, Inc. ("MISO") that it intends to suspend Campbell Units 1, 2 and 3 effective June 1, 2025. Attached is the notice of such intent in accordance with Section 38.2.7 and Attachment Y of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

Campbell Unit 3 is jointly owned by the Company (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that, pursuant to the relevant Operating Agreements, it is authorized to submit this Attachment Y notice on behalf of all Campbell Unit 3 owners.

In the event you have any questions regarding this matter, please contact Kathy Wetzel at (517) 788-2039.

Regards,

Timothy J. Sparks
Vice President Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Cc: Kathy Wetzel
Thomas Clark

Electric Supply
Contract/Commitment Cover Sheet

(Note: Contracts, purchase orders, or other commitment instruments will not be signed unless this sheet is completed in full)

Subject/Commitment: MISO Attachment Y Notification of Generating Resources /SCU/ Pseudo-tied Out Generator Change of Status / Including Notification of Rescission Form

Reason: Notice to Suspend Karn Units 3 & 4 effective June 1, 2023.

Check One			
Yes	No*	N/A	
☐	☐	☒	1) Gateway Assessment Tool completed and attached
☒	☐	☐	2) Legal Review / Approval to Form
☐	☐	☒	3) Credit Risk Management Approval
☐	☐	☒	4) Competitive Bid
☐	☐	☒	5) Sole Source Approval completed and attached

*If No is checked or special circumstances apply, please explain:

Legal review by Emerson Hilton.

*Contract Owner: Kathy Wetzel

Department Sign Off
(Signature & Date Required)

ML Metz
Merchant Ops & PSCR

KG Troyer
EGI Contracts & Settlements
Renewables

BD Gallaway
Fuel Supply

TP Clark
Electric Supply

12/14/2021

TJ Sparks
Electric Grid Integration

Form Revised: 04/16/21

*Contract Owner Responsible for Scanning & Placing on SharePoint Site

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic copy of the completed form will be accepted by the Transmission Provider, however, a form will not be considered complete until the original form containing an original signature, including all attachments, is received by the Transmission Provider at the following address: MISO, Attention: Director of Transmission Planning; 720 City Center Drive, Carmel, IN 46032.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re: Campbell Unit 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] CAMPBELL UNITS 1+2: UMBRELLA GIA BETWEEN CONSUMERS, METC + MISO FERC DOCKET ER21-999. CAMPBELL UNIT 3: FERC DOCKET ER06-1441 FOR MISO SERVICE AGREEMENT NO. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 1st [day] of June [month] of 2025 [year]

[ ] Rescind the current notice to SuspendThe facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: TIMOTHY J SPARKS

Title: VP ELECTRIC GRID INTEGRATION

Date:

Contact Information

Email: TIMOTHY.SPARKS@CMSENERGY.COM

Phone: 517 788 1053

Andrew Witmeier
Director, Resource Utilization
317-249-5585
awitmeier@misoenergy.org

VIA OVERNIGHT DELIVERY

March 11, 2022

Timothy J. Sparks
Vice President, Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Subject: **Approval of Campbell Units 1,2 &3 Attachment Y Suspension Notice**

Dear Mr. Sparks,

On December 14, 2021, Consumers Energy Company submitted an Attachment Y Notice to MISO for the suspension of Campbell Units 1,2 & 3, effective June 1, 2025. After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the suspension of Campbell Units 1,2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,2 & 3 may suspend without the need for the generators to be designated as a System Support Resource ("SSR") units as defined in the Tariff.

As there were no reliability criteria violations, MISO will continue to preserve the confidentiality of the Attachment Y Notice.

Please do not hesitate to contact me if you have any questions regarding this matter.

Respectfully,

Andrew Witmeier
Director, Resource Utilization

VIA EMAIL

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

May 28, 2025

Re: Modified Suspension Date for Campbell Units 1, 2, & 3

Mr. Witmeier:

On December 14, 2021, Consumers Energy Company ("Consumers Energy") submitted an Attachment Y Notice to the Midcontinent Independent System Operating, Inc. ("MISO") for the suspension of Units 1, 2, and 3 at the J.H. Campbell Generation Complex ("Campbell Plant"), effective June 1, 2025. After reviewing for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), MISO determined the suspension of Campbell Plant Units 1, 2, and 3, would not result in violations of applicable reliability criteria, as outlined in the Tariff. On March 11, 2022, MISO approved the suspension of Campbell Plant Units 1, 2, and 3 without the need for the generators to be designated as System Support Resource units as defined in the Tariff.

On May 23, 2025, the U.S. Department of Energy ("DOE") issued Order No. 202-25-3 (the "Order"), requiring the Campbell Plant to be available to MISO through August 20, 2025.

In order to comply with the Order, Consumers Energy hereby provides notice to MISO, consistent with Section 38.2.7(d)(ii)(1) of the Tariff, of its intent to modify the current Attachment Y Notice such that the Campbell Plant will now suspend on August 21, 2025.

As noted in Consumers Energy's original Attachment Y Notice, Campbell Unit 3 is jointly owned by Consumers Energy (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that it has notified all Campbell Unit 3 owners of this submittal.

In the event you have any questions regarding this matter, please contact Derek Anspaugh at (517) 788-1869.

Regards,

Sri Maddipati
VP Electric Supply
1945 W. Parnell Rd
Jackson, MI 49901

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic form must be submitted to the Transmission Provider via its online application tool in the manner specified by the Transmission Planning Business Practices Manual (BPM-020), and a form will be considered complete on the date of such online application.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re Campbell 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement]
Campbell Units 1 & 2: Umbrella GIA Between Consumers, METC, and MISO, FERC Docket No. ER24-1359
Campbell Unit 3: FERC Docket No. ER06-1441 for MISO Service Agreement No. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 21 [day] of August [month] of 2025 [year]

[ ] Rescind the current notice to Suspend

The facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: Srikanth Maddipati

Title: VP Electric Supply

Date: May 28, 2025

Contact Information

Email: sri.maddipati@cmsenergy.com

Phone: 517-788-0635

From:	Marc Keyser
To:	Rachael H. Moore; Huaitao Zhang; DEREK S. ANSPAUGH; Adam C. French; NICHOLAS B. TENNEY; Emerson J. Hilton
Cc:	Sumit Pal Brar
Subject:	RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required
Date:	Friday, May 30, 2025 4:05:01 PM

##CAUTION##: This email originated from outside of CMS/CE. Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Rachael: I'm responding back on behalf of the team, after they briefly reviewed with legal here:

we received the Attachment Y, and the new cessation is 8/21/2025. Additionally, you have until 8/21/2027 to submit a new replacement request before the suspension period ends. In other words, the Attachment Y remains as is, still approved, except with a new/different start date.

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Friday, May 30, 2025 12:15 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Warning! This email originated from outside the organization and caution should be used when clicking on links/attachments. If you suspect this email is malicious, use the 'Phish Alert' button.

Thank you, Huaitao. Can you confirm that this modification of the suspension start date provided consistent with Section 38.2.7(d)(ii)(1) of the Tariff does not impact the overall approval of the Attachment Y the Company previously received on March 11, 2022, and that the Company is still approved to enter suspension (now effective 8/21/25)?

Thank you!

Rachael Moore | Senior Attorney
[redacted]

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Wednesday, May 28, 2025 1:47 PM

To: Rachael H. Moore <Rachael.Moore@cmsenergy.com>; DEREK S. ANSPAUGH <DEREK.ANSPAUGH@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

##CAUTION##: This email originated from outside of CMS/CE.
Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Rachael,

Thanks for the quick response, and we are all good.

Thanks,
Huaitao

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Wednesday, May 28, 2025 12:40 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

> **Warning!** This email originated from outside the organization and caution should be used when clicking on links/attachments. If you suspect this email is malicious, use the 'Phish Alert' button.

Huaitao –

Attached is the modified Attachment Y with the amended suspension start date of 8/21/2025. Please let me know if we should send this notice of Modified Attachment Y to anyone else at MISO or if you would like us to mail a physical copy as well.

Thank you,
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Rachael H. Moore
Sent: Tuesday, May 27, 2025 11:52 AM
To: Adam C. French <adam.french@cmsenergy.com>; Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <nicholas.tenney@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Good afternoon,

Yes, I will be working with members of the Company to ensure we have the Attachment Y notice updated by 5/28. Please let me know if there is a specific contact at MISO we should plan to send this to.

Thank you!
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Adam C. French <ADAM.FRENCH@cmsenergy.com>
Sent: Tuesday, May 27, 2025 11:49 AM
To: Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

It is my understanding that is being handled by Rachael Moore
RACHAEL.MOORE@CMSENERGY.COM

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Tuesday, May 27, 2025 11:41 AM
To: NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: FW: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

You don't often get email from hzhang@misoenergy.org. Learn why this is important [aka.ms]

##CAUTION##: This email originated from outside of CMS/CE. Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Nick and Adam,

Marc pointed to me that you are the contact for this request.

Thanks,
Huaitao

From: Huaitao Zhang
Sent: Tuesday, May 27, 2025 11:05 AM
To: KATHY S. WETZEL <KATHY.WETZEL@cmsenergy.com>
Cc: timothy.sparks@cmsenergy.com; Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>; Jagdesh Shivani <JShivani@misoenergy.org>
Subject: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Hi Kathy,

Pertain to the Order from Secretary of Energy regarding the suspension/cessation date of Campbell units 1,2&3, MISO requests Consumer Energy to submit the following application updates to MISO by 5/28/2025:

Attachment Y request with suspension start date as 8/21/2025

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

Thanks,
Huaitao Zhang
Resource Utilization Engineer

Integrity | Collaboration | Commitment | Creativity | Adaptability

Attachment D

Consumers' Responses from June 10, 2025

Question:

23. Absent continued operation of the Campbell Plant, what was Consumers Energy's Zone Resource Credit (ZRC) position for planning year 2025-2026.

Response:

The table below shows our capacity positions using the initial Planning Reserve Margin Requirement (PRMR) for each season of planning year 2025. These numbers do not include any contributions from the Campbell coal-fired generating units.

PY2025	**ZRC**
Summer	272.9
Fall	842.7
Winter	0.0
Spring	4.3

Date: June 10, 2025

Question:

24. How many ZRCs does Consumers anticipate will be accredited for the continued operation of the Campbell Plant?

Response:

At this time we do not anticipate the Campbell units contributing any Zonal Resource Credits to our capacity positions throughout planning year 2025.

Date: June 10, 2025

Attachment Q

Petition for Review - COA DC SOM v USDOE
(DOE Order No. 202-25-3)

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

THE PEOPLE OF THE STATE OF MICHIGAN, *Petitioner*, v. UNITED STATES DEPARTMENT OF ENERGY, and CHRIS WRIGHT, Secretary, UNITED STATES DEPARTMENT OF ENERGY *Respondents*.	)	DOE Order No. 202-25-3

PETITION FOR REVIEW

Pursuant to Rule 15 of the Federal Rules of Appellate Procedure, Circuit Rule 15, and section 313(b) of the Federal Power Act, 16 U.S.C. § 825*l*(b), Michigan Attorney General Dana Nessel, on behalf of the People of the State of Michigan, hereby petitions the Court for review of the Order No. 202-25-3 of Respondents, Chris Wright, Secretary, United States Department of Energy, and the United States Department of Energy, issued on May 23, 2025 (the "Campbell Order," attached as Exhibit A). The Department of Energy issued the Campbell Order pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), a provision initially vested in the Federal Power Commission that was assigned to the Department through the Department of Energy Organization Act, 42 U.S.C. § 7151(b). As an order issued under the Federal Power Act, the Campbell Order is subject to the

rehearing and judicial review provisions of 16 U.S.C. § 825*l*. *See* 42 U.S.C. § 7192(a) ("Judicial review of agency action taken under any law the functions of which are vested by law in, or transferred or delegated to the Secretary [of Energy] . . . shall, notwithstanding such vesting, transfer, or delegation, be made in the manner specified in or for such law.").

On behalf of the People of the State of Michigan, the Michigan Attorney General participated in the proceedings before the Department of Energy and timely filed a request for rehearing of the Campbell Order. That rehearing request may be deemed denied by operation of law because the Department did not act upon it within 30 days. *See* 16 U.S.C. § 825*l*(a); Allegheny Def. Project v. FERC, 964 F.3d 1, 18-19 (D.C. Cir. 2020). Therefore, the Michigan Attorney General may file this petition for review under 16 U.S.C. § 825*l*(b). This Court has jurisdiction, and venue in this Court is proper, under 16 U.S.C. § 825*l*(b). The Michigan Attorney General respectfully requests that this Court hold unlawful, vacate, and set aside the Campbell Order, and grant such further relief as may be deemed just and proper.

Dated: July 24, 2025

Respectfully submitted,

Dana Nessel,
Michigan Attorney General

/s/ Michael Moody
Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

CC:
DOE:
AskCR@hq.doe.gov
The.secretary@hq.doe.gov

CECo:
Bret.totoraitis@cmsenergy.com
Kelly.hall@cmsenergy.com

Earthjustice:
mlenoff@earthjustice.org
sfisk@earthjustice.org
msoules@earthjustice.org
lpiette@earthjustice.org
sdoshi@earthjustice.org
cpowell@earthjustice.org
atom@earthjustice.org
astatler@earthjustice.org

MEC:
charlotte@environmentalcouncil.org

Sierra Club:
greg.wannier@sierraclub.org
sanjay.narayan@sierraclub.org
elena.saxonhouse@sierraclub.org

NRDC:
creiser@nrdc.org
gmccabe@nrdc.org

ELPC:
bklein@elpc.org

Clean Air Task Force:
dfidler@catf.us
fsturges@catf.us

Public Citizen, Inc.:
tslocum@citizen.org

Ecology Center:
alexis@ecocenter.org

Union of Concerned Scientists:
jgignac@ucs.org

UCC:
sergio@uccgr.org

Environmental Defense Fund:
tekelly@edf.org
tcarbonell@edf.org

Vote Solar:
will@votesolar.org

Midcontinent Independent:
tcaister@misoenergy.org
mkessler@misoenergy.org
jholsclaw@calfee.com
tcarpenter@calfee.com

Michigan Public Power:
arobbins@washingtonenergylaw.com
droby@washingtonenergylaw.com
tsteiger@washingtonenergylaw.com

Maryland Office of People:
William.fields@maryland.gov
Philip.sussler@maryland.gov
Alexis.lewis@maryland.gov

MISO States:
brad@misostates.org
tricia@misostates.org

Order No. 202-25-3

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 for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States 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

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[1] In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.[2]

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[3] Additionally EIA stated, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[4] The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to "speed closure" of Campbell in 2025, several years before the end of its scheduled design life.[5] Although MISO and Consumers have

[1] 2025 summer reliability assessment. (May 14, 2025). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf
[2] *Id*.
[3] U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: https://www.eia.gov/state/print.php?sid=mi.
[4] *Id.*
[5] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."

MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and the results "reinforce the need to increase capacity."[6]

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) 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.

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

A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

[6] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant 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.

D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also 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 of Energy from time to time.

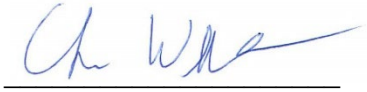
E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.

I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Order No. 202-25-3

REQUEST FOR REHEARING BY MICHIGAN ATTORNEY GENERAL DANA NESSEL

Dana Nessel
Michigan Attorney General

Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

Dated: June 18, 2025

Pursuant to section 313*l* of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Michigan Attorney General Dana Nessel, on behalf of the people of the State of Michigan, requests that the Department of Energy (Department or DOE) grant rehearing of Order No. 202-25-3 (May 23, 2025) ("Order"). The Order invoked the Department's emergency authority under section 202(c) of the Act to prevent the scheduled retirement of the J.H. Campbell power plant (J.H. Campbell) in West Olive, Michigan.

The Order is an unlawful abuse of the Department's emergency authority. Until now, the Department has reserved section 202(c) for real emergencies like natural disasters and extreme weather and has typically acted at the behest of grid operators or governmental bodies. In the Order, acting on its own motion and without notice, the Department declares that the retirement of J.H. Campbell presents an emergency. But the Order's emergency determination cannot bear even the mildest scrutiny.

The scheduled retirement of J.H. Campbell was the culmination of a carefully planned process that unfolded over four years. Under the oversight of the Michigan Public Service Commission (MPSC), Consumers Energy (Consumers) executed a plan to retire an old and inefficient facility, J.H. Campbell, and replace it largely with newer resources that would both increase Consumers' available generation capacity and save its ratepayers money. J.H. Campbell's proposed retirement was also studied carefully by the Midcontinent Independent System Operator (MISO), the regional

grid operator, which determined that the facility could retire without causing reliability issues.

In the Order, the Department uses its authority under section 202(c) in a manner untethered from the need to identify a real emergency and unhindered by the statutory requirement that the actions it orders go no further than necessary to address the emergency. The result of this overreach will be unnecessary costs imposed on already-overburdened ratepayers, needless pollution emitted into Michigan and its neighboring states, and an unprecedented intrusion into the authority of states and the Federal Energy Regulatory Commission to regulate the resource adequacy of our electric grid.

I. MOTION TO INTERVENE

The Michigan Attorney General,[1] on behalf of the people of the State of Michigan, moves to intervene in this proceeding and thereby to become a party for purposes of Section 313*l* of the Act, 16 U.S.C. § 825*l*. The People of the State of Michigan have an interest in and are aggrieved by the Order in several ways. First, households and businesses in Michigan will pay higher electricity bills as a result of the Order. The retirement of J.H. Campbell and its replacement with more cost-effective resources were elements of a careful plan expected to save Michigan

[1] *See* MCL 14.28 ("The attorney general . . . may, when in [her] own judgment the interests of the state require it, intervene in and appear for the people of this state in any other court or tribunal, in any cause or matter, civil or criminal, in which the people of this state may be a party or interested."). *See also In re Certified Question*, 465 Mich 537, 543-545; 638 NW2d 409 (2002), *Gremore v Peoples Community Hospital Authority*, 8 Mich App 56; 153 NW2d 377 (1967), and *People v O'Hara*, 278 Mich 281; 270 NW2d 298 (1936).

ratepayers nearly $600 million.[2] By ordering the continued operation of J.H. Campbell, the Order ensures that Michigan ratepayers will pay higher costs. Although the precise amounts of costs are not yet known, it is certain that Michigan ratepayers will be stuck with substantial new costs in excess of what they would have paid absent the Order.

Second, the People of the State of Michigan will suffer environmental harms as a result of the Order. J.H. Campbell is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[3] among other pollutants. By prolonging the operations of J.H. Campbell beyond its planned retirement date, the Order will increase the amount of pollution emitted in the state of Michigan, causing harms to the public health and welfare.

Third, the retirement of J.H. Campbell on May 31, 2025, was a provision agreed to as part of a settlement agreement in Michigan Public Service Commission Case (MPSC) No. U-21090, to which the Michigan Attorney General was a party. Because the Order deprives the Michigan Attorney General of the benefit of her bargain under the settlement agreement, the Michigan Attorney General will suffer a discrete and separate harm as a result of the Order.

II. BACKGROUND

A. DOE's Historical Use of Section 202(c).

[2] *See* Michigan Public Service Commission Case No. U-21090-0867, Reply Brief of Consumers at 1 – 2, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y0000032ZSXAA2.
[3] *See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).

In the past, the Department has used section 202(c) sparingly. The Department has used this authority only in response to concrete, particularized emergencies, and subject to limitations to ensure that the Department's reach extends no further than necessary to address the emergency at hand.

Between enactment of the Department of Energy Organization Act in 1977, Pub. L. No. 95-91, and the end of last year, the Department appears to have used section 202(c) nineteen times, not counting amendments and extension orders. DOE's first usage of section 202(c) came in response to the California Energy Crisis in 2000.[4] That order was followed by two others directing the operation of the Cross-Sound Cable, a submarine transmission line connecting New York and Connecticut that was complete but that had been delayed from entering service due to environmental permitting issues.[5] But by far the most common usage – comprising 13 of 19 instances – has been in response to extreme weather events such as hurricanes,[6] extreme cold,[7] and extreme heat.[8] In each of these weather-driven cases, the exercise of emergency power was requested by the relevant system operator or responsible utility, or both.

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[4] DOE, *Order Pursuant to Section 202(c) of the Federal Power Act* (Dec. 14, 2000). Section 202(c) was used by the Federal Power Commission prior to the Department of Energy Organization Act's creation of DOE. Those uses were generally limited to orders directing interconnection as a result of discrete and sudden emergencies or war. *See* Benjamin Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. 789, 822 (2025).

[5] *See* DOE Order No. 202-02-1 (Aug. 16, 2002); DOE Order No. 202-03-01 (Aug. 14, 2003).

[6] *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (response to Hurricane Rita); DOE Order No. 202-08-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton).

[7] *See* DOE Order No. 202-21-1 (Feb. 14, 2021); DOE Order No. 202-22-3 (Dec. 23, 2022); DOE Order No. 202-22-4 (Dec. 24, 2022).

[8] *See* DOE Order No. 202-20-2 (Sept. 6, 2020) (responding to extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 202-22-1 & 2 and amendments (same).

And in each, DOE carefully limited its remedy to ensure that generation facilities were only ordered to run in circumstances necessary to address the emergency and in a manner so as to minimize any conflict with environmental requirements.[9] DOE also limited the duration of those orders to the minimum period necessary to address the emergency, often shorter than 10 days.[10]

Prior to the Order, DOE had used section 202(c) on three occasions to delay the retirement of generation facilities.[11] These cases had key features in common. In each: (i) the order was requested by a system operator or governmental body; (ii) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (iii) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and, (iv) DOE tailored its order to go no further than necessary to address the emergency.

The first such instance came in 2004, when the District of Columbia's Public Service Commission requested an order directing the continued operation of a power plant located in Alexandria, Virginia, owned by the Mirant Corporation (Mirant). After its state regulator found the plant to be out of compliance with its air permit, Mirant abruptly announced that the plant would close.[12] The D.C. Public Service Commission, supported by the local utility, PEPCO, explained that the Mirant facility

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[9] *See supra* notes 3 – 5.
[10] *Id*.
[11] Nor did the DOE's predecessor agency, the Federal Power Commission, use section 202(c) to delay retirement of any generation units between the section's enactment in 1935 and the formation of DOE in 1977. *See* Rolsma, 57 U. Conn. L. Rev. at 843-46.
[12] DOE Order No. 202-05-3 (Dec. 20, 2005) at 1 (explaining that Mirant provided emissions information to its state regulator on August 19, 2005, the regulator demanded immediate action that same day, and Mirant decided to cease operations on August 24).

directly powered downtown D.C. and that, without it, critical federal infrastructure faced an unacceptable risk of blackout.[13] Before acting on the request, the Department commissioned an analysis from the Oak Ridge National Laboratory that confirmed the threat that the plant's closure would pose to reliability in D.C.[14] Based on that study, and based on the severity of the harm that could result from a prolonged power outage to downtown D.C., the Department issued an order directing the continued operation of the Mirant facility.[15] The Department took pains, however, to limit its order to go no further than necessary to address the emergency. The Department directed Mirant to maintain the facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[16]

Twelve years later, in 2017, the Department received a request from the Grand River Dam Authority (GRDA), an Oklahoma state agency, to direct the continued operation of Unit No. 1 at the Grand River Energy Center. GRDA explained that the Grand River Energy Center was needed to provide dynamic reactive power support to the local grid, a fact confirmed by the region's Reliability Coordinator, the Southwest Power Pool (SPP). GRDA explained, however, that it would be unable to provide reactive power without action from DOE. Unit No.1, the subject of the request, had been ordered to close by an Administrative Order of the Environmental Protection Agency. Unit No. 2 had been struck by lightning and was under repair.

[13] *Id*. at 2.
[14] *Id*. at 3 – 4.
[15] *Id*. at 5 – 8.
[16] *Id*. at 10 – 11.

And, construction of the new Unit No. 3 had been delayed because flooding in Louisiana interfered with the fabrication of essential project materials.[17] The Department granted GRDA's request, ordering Unit No. 1 to remain in operation for 90 days or until Unit No. 2 or Unit No. 3 were brought online, whichever came first.[18] The Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[19]

Later that year, the Department received a pair of requests from PJM and Dominion Virginia (Dominion) to direct the continued operation of Units 1 and 2 of the Yorktown Power Station. PJM and Dominion explained that, based on PJM load flow studies, these units were necessary to prevent uncontrolled power disruptions and shedding of critical loads in the North Hampton Roads area east of Richmond.[20] DOE issued an order directing Dominion to maintain operation at the two units, but to dispatch those units "only when called upon by PJM for reliability purposes."[21] DOE later extended the order several times due to the delayed completion of the transmission line needed to resolve the reliability issue. In doing so, DOE cited the "imminent" risk of load-shedding in the North Hampton Roads area absent extension of the order.[22] In its extension order, the Department continued to limit dispatch of

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[17] Letter Request of Grand River Dam Authority, April 11, 2017. Available at https://www.energy.gov/sites/default/files/2017/05/f34/GRDA%20public%20202%28c%29%20letter.pdf.
[18] DOE Order No. 202-17-1 at 2.
[19] *Id*.
[20] DOE Order No. 202-17-2, at 1.
[21] *Id*. at 2.
[22] DOE Order No. 202-17-4, Summary of Findings, Sept. 14, 2017.

the units only when called upon by PJM for reliability purposes and, further, directed PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating the units.[23]

B. Executive Order 14262 and the White House Strategy to Prop Up the Coal Industry.

Over the past several months, the White House and the Department have sought to radically transform how section 202(c) of the Federal Power Act is applied, departing in almost every material respect from the longstanding approach described above. As shown below, the Order cannot be understood intelligibly as a response to a discrete event or emergency akin to past orders under section 202(c). Rather, it can only be understood as part of a long-term and multi-part strategy to preserve coal and other fossil fuel generation under the guise of grid reliability concerns.

On April 8, 2025, President Trump issued Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*.[24] The Executive Order was issued concurrently with three other executive actions aimed at supporting the coal industry that were announced at a White House political event explicitly focused on that objective.[25] This event, and the related Executive Order, are one of several in a series of public actions by the Administration aimed at reversing coal plant retirements and promoting fossil fuel generation.

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[23] DOE Order No. 202-17-4 at 2.
[24] Executive Order 14262, 90 Fed. Reg. 15521 (April 14, 2025).
[25] New York Times, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry* (April 8, 2025); Executive Order 14261, *Reinvigorating Americans Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15517 (April 14, 2025); Executive Order 14260, *Protecting American Energy from State Overreach*, 90 Fed. Reg. 15513 (April 14, 2025); *Regulatory Relief for Certain Stationary Sources To Promote American Energy*, 90 Fed. Reg. 16777 (April 21, 2025).

Executive Order 14262 directs DOE to, among other things, streamline and expedite the issuance of emergency orders under section 202(c), specifically in order to "safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply [that] is necessary to prevent a complete grid failure."[26] It also directs DOE to take a subsequent series of actions related to national resource adequacy, including mandating:

- the development of a uniform methodology for assessing reserve margins and identifying "at-risk" regions;
- establishment of a process by which the developed methodology and any analysis results are regularly assessed; and,
- establishment of a protocol to identify generation resources within a region that are critical to system reliability, a mechanism under section 202(c) to ensure such generation resources are appropriately retained and, for resources over 50MW, are prevented from leaving the bulk-power system or converting their source of fuel.[27]

DOE has not yet published the analysis or protocols—the deadline provided in Executive Order 14262 is July 7.

Executive Order 14262 states that it is intended to help address the national energy emergency declared in the earlier-issued Executive Order 14,156, *Declaring a National Energy Emergency*.[28] In fact, this order is part of a broader pattern in which the Administration has expansively invoked emergency powers to achieve long-standing political objectives, rather than respond to genuine, unforeseen crises. The

[26] Executive Order 14262 section 3(a).
[27] Executive Order 14262 section 3(b), (c).
[28] Executive Order 14262, section 2.

President has declared eight national emergencies in 2025 alone—more than any other President in the first 100 days of an administration.[29]

C. The Planned Retirement of JH Campbell.

i. Description of J.H. Campbell

J.H. Campbell is a three-unit coal-fired power plant with a total rated net generating capability of approximately 1,450 megawatts (MW).[30] (The Order incorrectly states that J.H. Campbell has a capacity of 1,560 MW). In its current degraded condition, however, J.H. Campbell has a maximum capacity of 920 MW.[31] Part of that difference comes from the fact that Unit 2 is not operational, nor was it operational when the Order was issued. When Unit 2 comes back on-line later this month, the maximum capacity of the facility will be 1,180 MW. J.H. Campbell Unit 1 is 63-years-old and has a rated net generating capability of 261 MW, but now has an effective maximum output of 220 MW.[32] Unit 2 is 58-years-old and has a rated net generating capability of 356 MW. Currently out of service, when Unit 2 comes back online it will have a maximum capacity of 260 MW.[33] Unit 3 is 45 years old and has a rated net generating capability of 843 MW. The current maximum capacity of Unit 3 is 700 MW.[34] Consumers operates the entire J.H. Campbell plant and is the sole

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[29] *See* https://www.brennancenter.org/our-work/research-reports/declared-national-emergencies-under-national-emergencies-act.

[30] Michigan Public Service Commission (MPSC) Case No. U-21585, Direct Testimony of Richard Blumenstock, p. 7, Table 1 (5 Tr 1394-95); see also, https://www.consumersenergy.com/about-us/electric-generation/campbell-complex-retirement, last checked June 11, 2025 (reporting 1,450 MW of capacity).

[31] Conversation between representatives of Consumers and the undersigned counsel, June 12, 2025.

[32] *Id.*

[33] *Id.*

[34] *Id.*

owner of Units 1 and 2. Consumers owns about 93% of Unit 3, the Michigan Public Power Agency owns 4.8% of Unit 3, and Wolverine Power Supply Cooperative owns less than 2% of Unit 3.[35]

J.H. Campbell and Consumers' service territory are located within MISO Local Resource Zone 7. Most of the lower peninsula of Michigan is in MISO Zone 7, except for a small area in the southwest portion of the State, which is in PJM.

ii. State proceeding approving the retirement of J.H. Campbell

In 2021, Consumers proposed to retire J.H. Campbell in 2025 for economic reasons. The MPSC thoroughly reviewed the proposed retirement for a year in an integrated resource plan (IRP) proceeding governed by Michigan statute.[36] No party in the case opposed the retirement of Units 1 and 2; and only a few opposed the retirement of Unit 3.[37] The MPSC ultimately approved Consumers' proposed retirement of J.H. Campbell in a settlement joined by most of the parties to the case. A single party appealed the MPSC's decision to approve the retirement of Unit 3, but the Michigan Court of Appeals affirmed that decision in 2023.[38] Both the MPSC and the appeals court found that Michigan would still have more than enough generating capacity to serve demand after J.H. Campbell retired.[39]

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[35] MPSC Case No. U-21090 (Kapala Direct, 7 Tr 1739); Ex. WPSC-1, p. 19 (Agreement, p. 11), section 2.1, available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001QqldAAC.

[36] MCL 460.6t.

[37] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 8.

[38] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[39] *Id.*

Michigan's IRP statute requires electric utilities whose rates are regulated by the MPSC to periodically file an integrated resource plan. The IRP is a projection of the utility's load obligations and a plan to meet those obligations.[40] The IRP statute directs the MPSC to approve a plan if the MPSC determines that it "represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."[41] To make that decision, the statute instructs the MPSC to consider whether the IRP appropriately balances seven statutory factors: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective.[42]

The IRP statute also directs the MPSC to establish – among other things – computer modeling scenarios that must be used to analyze the costs of possible plans in an IRP, including costs associated with plant retirement dates.[43] In the modeling used to prepare its 2021 IRP, Consumers determined that it would be most cost-effective to retire the entire J.H. Campbell plant in 2025.[44] Later in the proceeding, Consumers conducted more modeling that compared other possible retirement dates

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[40] MCL 460.6t(3).

[41] MCL 460.6t(8)(a).

[42] *Id.*

[43] MCL 460.6t(1).

[44] MPSC Case No. U-21090 (Blumenstock Direct, 3 Tr 99 and 147-49), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001OEXnAAO.

to a 2025 retirement and again concluded that the most cost-effective retirement date was 2025.[45] Among other things, parties to the IRP case noted that the 2025 retirement of J.H. Campbell would save ratepayers $150 million in avoidable capital expenditures.[46]

After months of litigation, most of the parties reached a settlement agreement, which Consumers filed with the MPSC on April 20, 2022.[47] The settlement agreement approved the retirement of J.H. Campbell – but it also approved the construction, procurement, and extension of other major generating resources. The net effect of these changes was to substantially increase the total generating resources available to MISO Zone 7.

iii. Effect of Consumers' overall plan on resource adequacy

MISO measures capacity for resource adequacy purposes in zonal resource credits (ZRCs). One ZRC is equal to one MW of deliverable seasonal accredited capacity, which is the net amount of capacity MISO calculates it can reasonably expect from a resource.[48]

Consumers' IRP projected that the entire J.H. Campbell plant would provide 1,346 ZRCs in 2024, its last full year of planned operation.[49] In recognition of the

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[45] *Id*. (Walz Rebuttal, 3 Tr 364-73 & Ex A-123; Blumenstock Rebuttal, 3 Tr 178-79).

[46] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, pp. 48, 55.

[47] MPSC Case No. U-21090-0777 (Settlement Agreement), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002gLkGAAU.

[48] MISO Knowledge Base, KA-01402, available at https://help.misoenergy.org/knowledgebase/article/KA-01402/en-us#:~:text=Zonal%20Resource%20Credits%20(ZRC)%20are,Seasonal%20Accredited%20Capacity%20(SAC); MISO, Resource Adequacy, available at https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc.

[49] MPSC Case No. U-21090, Order approving contested settlement, June 23, 2022, p. 33.

reduced capacity that would result from the retirement of J.H. Campbell, the settlement authorized Consumers to acquire the Covert gas plant, which Consumers has done.[50] At the time, the Covert plant was in the PJM regional transmission organization – but after acquiring it, Consumers redesignated the Covert plant as part of MISO Zone 7.[51] This action added 1,114 ZRCs to Zone 7 – almost enough by itself to offset the ZRCs removed by the Campbell retirement.[52]

The settlement also authorized Consumers to continue operating Units 3 and 4 of the Karn plant – peaking units that burn natural gas and oil – until 2031, rather than retire them in 2023 as originally planned.[53] This action maintained another 784 ZRCs in Zone 7 beyond what was in Consumers' original plan.[54] The settlement agreement also authorized Consumers to develop or acquire 250 ZRCs of new solar generation by mid-2025, increasing to 852 ZRCs by mid-2028; added 94 ZRCs of demand response and energy waste reduction by mid-2025; and added 71 ZRCs of new battery storage in 2024-2027.[55] The settlement also provided that Consumers would issue a solicitation for power purchase agreements (PPAs) that would provide capacity beginning in 2025/2026, right after J.H. Campbell's retirement.[56] The PPA solicitation would seek up to 500 MW of dispatchable generation, and up to 200 MW of clean energy resources.[57]

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[50] *Id*. at 5.
[51] *Id*. at 91.
[52] *Id*. at 50.
[53] *Id*. at 11.
[54] *Id*.
[55] *Id*. at 23.
[56] *Id*. at 6 – 7. In MISO, the planning year runs from June 1 through May 31.
[57] *Id*.

Overall, the plan approved in the settlement was projected to increase Zone 7's capacity by at least 127 ZRCs by June 2025 – an increase that will grow to at least 923 ZRCs by 2028, not including the 700 MW of additional capacity sought in the PPA solicitations.[58]

iv. MPSC approval of the settlement and affirmance on appeal

Consumers' IRP settlement agreement was supported by most parties in the case, including Consumers, Staff, the Attorney General, consumer advocates, a transmission company, commercial and industrial customers, businesses in the advanced energy sector, environmental groups, and third-party energy developers.[59] The MPSC approved the Settlement Agreement on June 23, 2022.[60] The state commission found that the plan embodied in the settlement "is the most reasonable and prudent means of meeting Consumers' energy and capacity needs."[61]

In reaching these conclusions, the MPSC specifically addressed resource adequacy.[62] After discussing the record evidence regarding the Covert plant, Karn units 3 and 4, new battery storage, and ongoing investments in solar, energy waste reduction, and demand response,[63] the MPSC concluded that "the approval of the settlement agreement will enhance resource adequacy in Zone 7 in both the near-term and long-term."[64] One party, Wolverine Power Supply Cooperative, appealed

[58] *Id.* at 24.
[59] *Id.* at 30 – 31.
[60] *Id.* at 87-93.
[61] *Id.* at 95.
[62] *Id.* at 90-93.
[63] *Id.*
[64] *Id.* at 92.

the MPSC's decision to approve the Campbell plant retirement. The Michigan Court of Appeals affirmed the MPSC. The court specifically addressed resource adequacy, quoted the MPSC's findings about the generating resource additions, and found that the state commission's decision was based on substantial evidence.[65]

v. Subsequent proceedings before the MPSC show that both Consumers' service territory and Michigan as a whole will have sufficient capacity this summer and for years to come

Filings in MPSC proceedings regarding capacity supply and resource adequacy demonstrate that there is no capacity shortfall. To the contrary, the most current available information is that both Consumers and MISO Zone 7 will have sufficient capacity this summer and for years to come. On June 10, 2025, Consumers reported that it now has a surplus of 273 ZRCs for this summer.[66] Consumers further reported that it expects J.H. Campbell will not contribute any ZRCs to the Company's summer position.[67]

Consumers' ZRC projections compare Consumers' available resources not just to projected actual demand but to the planning reserve margin requirement (PRMR). MISO establishes the PRMR as the amount of reserve margin target necessary to meet NERC's Loss of Load Expectation (LOLE) standard of 1 day in 10 years.[68] NERC

[65] *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*, 2023 Mich. App. LEXIS 2045; 2023 WL 2620437 (March 23, 2023).

[66] *See* Attachment D, Consumers' Responses from June 10, 2025.

[67] *Id*.

[68] MISO Resource Adequacy Business Practices Manual, BPM-011-r31, p. 27, Section 3.4.2 LOLE Analysis; MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 9.

defines the LOLE as "the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand."[69]

For Michigan as a whole, the MPSC Staff finds in its annual capacity demonstration report that – except for one small municipal utility – all Michigan load serving entities "were able to procure the necessary capacity to demonstrate compliance for the current planning year in all four seasons" in Planning Year 2025-26.[70] The Staff Report also finds that there are more than enough resources in Zone 7 to meet the MISO Local Clearing Requirement (LCR) – which is the minimum amount of resources that must be located within a MISO local resource zone to meet the reliability standard.[71] While Zone 7 did not have enough internal resources to meet its entire PRMR, it is not required to do so under MISO rules, and the zone is able to import 785.5 ZRCs of external resources to meet its PRMR for the current planning year.[72]

Looking ahead, the Staff Report projects that Zone 7 will have more than enough resources to meet both its LCR and the PRMR in each of planning years 2026, 2027, and 2028.[73] Zone 7's LCR surplus will increase each year to reach 4,975 ZRCs by Planning Year 2028, and its PRMR surplus will increase each year to reach 3,428 ZRCs by Planning Year 2028.[74]

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[69] NERC Probabilistic Assessment Technical Guideline, August 2016, p. 2.
[70] MPSC Case No. U-21775, Capacity Demonstration Results Report, May 12, 2025, p. 6.
[71] *Id*. at 16.
[72] *Id*.
[73] *Id*. at p. 26, Appendix C.
[74] *Id*.

vi. MISO approved the retirement of J.H. Campbell after a detailed study process governed by MISO's FERC-approved tariff

More than three years before the Secretary issued Order 202-25-3, MISO determined via a detailed technical study that retirement of J.H. Campbell would not materially impact reliability in MISO. That determination remains in effect.

Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires that the owner of a Generation Resource that is planning to suspend operations of all or a portion of that resource must notify MISO at least 26 weeks in advance by submitting a completed Attachment Y Notice.[75] The Tariff states that MISO will perform an Attachment Y Reliability Study to determine whether the Generation Resource is necessary for the reliability of the Transmission System based on analyses described in the Tariff and criteria in the MISO Business Practices Manuals.[76]

On December 14, 2021, Consumers submitted to MISO an Attachment Y notice of intent to suspend J.H. Campbell Units 1, 2, and 3 effective June 1, 2025.[77] After more than a year of study, MISO approved the suspension on March 11, 2022.[78] MISO stated that after reviewing the J.H. Campbell suspension for power system reliability impacts, MISO had determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,

[75] MISO Tariff, Section 38.2.7(a)(i).
[76] MISO Tariff, Section 38.2.7(c).
[77] Attachment C (Letter dated December 14, 2021, from Timothy J. Sparks, Consumers Energy, to Andrew Witmeier, MISO, and Attachment Y Notification of Generating Resources Change of Status).
[78] Attachment C (Letter dated March 11, 2022, from Andrew Witmeier, MISO, to Timothy J. Sparks, Consumers Energy, re: Approval of Campbell Units 1, 2 & 3 Attachment Y Suspension Notice).

2 & 3 may suspend without the need for the generators to be designated as a System Support Resource ('SSR') units as defined in the Tariff."[79]

On May 27, 2025, MISO requested that Consumers submit a modified Attachment Y request with a new suspension start date of August 21, 2025, consistent with the date in Order 202-25-3.[80] Consumers submitted the modified Attachment Y notice with the new date on May 28, 2025.[81] On May 30, 2025, MISO notified Consumers that with the modification, "the Attachment Y remains as is, still approved, except with a new/different start date."[82]

D. The Order

On May 23, 2025, the Secretary of Energy issued the Order pursuant to section 202(c) of the Federal Power Act, determining that an emergency exists in the region of the country served by MISO "due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" and ordering Consumers and MISO to ensure the continued operation of J.H. Campbell for at least 90 days notwithstanding the longstanding plan to retire the facility on May 31, 2025. In issuing the Order, the Department issued a press release that, like Executive

[79] *Id*.
[80] Attachment C (Email dated May 27, 2025, from Huaitao Zhang, MISO, to Kathy Wetzel, Consumers Energy).
[81] Attachment C (Email dated May 28, 2025, from Rachael Moore, Consumers Energy to Huaitao Zhang, MISO).
[82] Attachment C (Email dated May 30, 2025, from Marc Keyser, MISO, to Rachael Moore, Consumers Energy).

Order 14262, states the Order "is in accordance with President Trump's Executive Order: Declaring a National Energy Emergency."[83]

Over four short paragraphs, the Order outlines the "emergency situation" allegedly necessitating invocation of section 202(c) authority. It points primarily to "*potential* tight reserve margins during the summer 2025 period," citing to the North American Electric Reliability Corporation (NERC) 2025 Summer Reliability Assessment, including the statement that MISO is "at elevated risk of operational reserve shortfalls during periods of high demand or low resource output."[84] The Order then describes the retirement of thermal generation capacity including the retirement of approximately 2,700 MW of coal-fired capacity in Michigan since 2020 and the scheduled May 31, 2025, retirement of J.H. Campbell.[85] The Order acknowledges Consumers' acquisition of 1,200 MW of replacement natural gas capacity and MISO's April 2025 conclusion that its auction resulted in "demonstrated sufficient capacity,"[86] but does not reference, let alone consider, the extensive processes that MISO and the MPSC undertook to evaluate and mitigate any reliability or resource adequacy risk that would be caused by the retirement of J.H. Campbell.[87] Nor does the Order describe any actions that MISO or Consumers have taken or could take to mitigate any alleged emergency conditions short of ordering the continued operation of the plant. Rather, it relies almost exclusively on:

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[83] DOE Press Release (May 23, 2025) available at https://www.energy.gov/articles/energy-secretary-issues-emergency-order-secure-grid-reliability-ahead-summer-months.
[84] DOE Order 202-25-3 at 1 (emphasis added).
[85] *Id.* at 1.
[86] *Id.* at 2.
[87] *See* Section II.C *supra*.

- The general statement in NERC's 2025 Summer Reliability Assessment that there is anticipated to be "elevated risk of operating reserve shortfalls"
- Language in MISO's Planning Resource Auction Results for Planning Year 2025-26 that, "for the northern and central zones, which includes Michigan, 'new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources,'" and that the results "reinforce the need to increase capacity" and,
- Language from the MISO Auction Results that the summer months have, relative to other times, the "highest risk and tighter supply-demand balance."[88]

The Order concludes that "additional dispatch of the Campbell Plant," for the 90-day duration of the order and on conditions contained in the order, "is necessary to best meet the emergency and serve the public interest."[89] As a result, the Order mandates that:

- MISO and Consumers Energy take all necessary steps to ensure the Campbell Plant is available for dispatch;[90]
- MISO employ economic dispatch of the plant, and that Consumers comply with all such dispatch orders;[91]
- All operation of J.H. Campbell "must comply with applicable environmental requirements . . . to the maximum extent feasible while operating consistent with the emergency conditions."[92]
- MISO submit reports to DOE on plant operations, environmental impacts, and actions taken to comply with the Order.[93]
- "Relevant governmental authorities" take such action as necessary to enable MISO to effectuate the dispatch and operation of the units.[94]
- Consumers request any necessary revisions or waivers to effectuate the order with FERC.[95]

III. STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

[88] DOE Order 202-25-3 at 2.
[89] DOE Order 202-25-3 at 2.
[90] *Id.* at 2 (Ordering Paragraph A).
[91] *Id.* (Ordering Paragraph A).
[92] *Id.* at 3 (Ordering Paragraph C).
[93] *Id.* at 3 (Ordering Paragraph B, D).
[94] *Id.* at 3 (Ordering Paragraph E).
[95] *Id.* at 3 (Ordering Paragraph F).

As explained in Section IV below, the Michigan Department of Attorney General submits the following statement of issues and specifications of error:

1. The Order is contrary to law because it fails to establish the existence of an emergency under section 202(c) or the Department's regulations implementing section 202(c). The statutory text, legislative history, judicial construction and DOE's regulations all confirm that an "emergency" is an occurrence that is sudden, unexpected and requiring immediate action. The Order introduces no facts that would satisfy that definition. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371; *Richmond Power and Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978); *Otter Tail Power Co. v. Fed. Power Comm*., 429 F.2d 232, 233-34 (1970).

2. The Order is contrary to law because it exceeds the Department's statutory authority. Abusing a statute meant only for emergencies, the Order intrudes on authority reserved to States and to other federal regulators to regulate resource adequacy. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy, or the authority to decide which power plants may retire except for so long as a true emergency exists. The Department may not "discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority." *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

3. The Order fails to present substantial evidence for its emergency determination and fails to exercise reasoned decision-making by ignoring critical facts and shortcomings in its analysis. Specifically, the Order: (i) presents a discussion of the NERC 2025 Summer Reliability Assessment that is unreasoned, incomplete, and that fails to substantiate the existence of an emergency; (ii) the Order's apparent reliance on generator retirements in Michigan as evidence of an emergency is unreasonable; (iii) the Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless, (iv) the Order fails even to acknowledge that MISO approved the retirement of J.H. Campbell through the study process governed by its FERC-approved tariff; (v) the Order makes no effort to review the proceedings before the MPSC, or to note any consultation with Michigan officials as required by 42 U.S.C. § 7113; (vi) the Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate. *E.g. Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017) (order under the Federal Power Act must reflect "a principled and reasoned decision supported by the evidentiary record" (quotation marks omitted)); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (agency must examine the relevant data and articulate a satisfactory

explanation for its action including a rational connection between the facts found and the choice made); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962) (an "agency must make findings that support its decision, and those findings must be supported by substantial evidence").

4. The Order is arbitrary and capricious and contrary to law because section 202(c) provides no authority for the Department to command a generator to engage in "economic dispatch." 16 U.S.C. § 824a(c); *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001) (absent statutory authorization, an agency's "action is plainly contrary to law and cannot stand").

5. The Order is arbitrary and capricious and contrary to law because the Department failed to limit its remedy as required by section 202(c)(2). The Order adheres to neither the temporal constraint nor the environmental constraints imposed by section 202(c)(2). 16 U.S.C. § 824a(c)(2).

6. The Order violates the National Environmental Policy Act because it fails to assess the environmental consequences of a major federal action significantly affecting the human environment. 42 U.S.C. § 4321; *et seq*.

IV. REQUEST FOR REHEARING

A. The Department Has Failed to Establish the Existence of an Emergency under Section 202(c) or the Department's Regulations Implementing Section 202(c).

i. Congress limited DOE's authority under section 202(c) to the unique circumstances of war or emergency

Section 202(c) confers an extraordinary power. Enacted in 1935, section 202(c) empowered the Federal Power Commission to command action from market participants and – crucially – to do so freed from most of the core procedural safeguards, jurisdictional boundaries, and substantive limitations that undergird the rest of the Federal Power Act. While the rest of the Act authorizes Commission action

only after opportunity for hearing,[96] section 202(c) allows the Commission (now the Department) to act on its own motion and without prior notice. And in profound contrast to the rest the Federal Power Act and general utility law principles,[97] section 202(c) empowers the Department to require utilities to incur costs – through a command to provide generation or transmission service – without first considering the impact to ratepayers or whether the resulting rates will be just and reasonable.

It comes as no surprise, therefore, that when Congress granted the Commission this extraordinary power, Congress restricted its use to extraordinary circumstances. Section 202(c) authorizes action only "[d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." The Act permits some measure of flexibility with respect to what type of events may cause the emergency, allowing for "other causes" beyond those enumerated. But the Act is clear that any such event, including a "shortage of electric energy," must be one that constitutes an "emergency."

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[96] *See e.g.*, 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o & 824p.

[97] Two cornerstones of the law of regulated utilities are the filed rate doctrine and the rule against retroactive ratemaking. As FERC has explained, "a central purpose of the filed rate doctrine and the rule against retroactive ratemaking is to protect ratepayers from being subjected to an additional surcharge above the rate on file for service already performed." *Old Dominion Elec. Coop.*, 154 FERC ¶ 61,155 (2016). In its June 6, 2025, complaint filed in FERC Docket No. EL25-90, Consumers asserts that the filed rate doctrine and the rule against retroactive ratemaking are inapplicable in the context of an order under section 202(c).

Because the Act does not define "emergency," the Department must look first to the public meaning of that word at the time of enactment. Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "sudden or unexpected appearance or occurrence . . . . An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency." Contemporary dictionaries likewise define "emergency" to refer to a circumstance that is "unexpectedly arising, and urgently demanding immediate attention."[98]

These definitions accord with the legislative history of the Federal Power Act, which characterized section 202(c) as an authority to be used in response to "crises":

> This is a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose. Drought and other natural emergencies have created similar crises in certain sections of the country; such conditions should find a federal agency ready to do all that can be done in order to prevent a break-down in electric supply.[99]

The few courts that have had occasion to opine on the meaning of "emergency" in section 202(c) have likewise emphasized that the provision applies in very limited circumstances, and not as a tool to address longer-term, structural concerns. In *Richmond Power and Light v. FERC*, the D.C. Circuit upheld the Commission's judgment that the dependence on foreign oil occasioned by the 1973 oil embargo was

[98] *See Acuity Ins. Co. v. McDonald's Towing & Rescue, Inc.,* 747 F. App'x 377, 380–81 (6th Cir. 2018) (addressing a statute that leaves "emergency" undefined and quoting 7 Oxford English Dictionary 231 (2012) among others to supply a definition).
[99] S. Rep. No. 74-621 at 49 (1935).

not an "emergency" under the Act, noting that section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[100]

In *Otter Tail Power Co. v. Fed. Power Comm'n,* the U.S. Court of Appeals for the Eighth Circuit described section 202(c) as enabling the Commission to "react to a war or natural disaster." The court also distinguished section 202(c) from section 202(b), under which the Commission may also order interconnections, but only after a hearing. The court explained that, in contrast to section 202(c), which "enables the Commission to proceed without notice or hearing" to address immediate crises, section 202(b) "applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[101]

Through its regulations, the Department has also interpreted "emergency" for purposes of section 202(c) to mean circumstances that arise suddenly and unexpectedly:

> "Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities.[102]

In summary, the plain meaning of the statutory text, its legislative history, judicial construction, and the Department's own regulations all establish that an

[100] 574 F.2d 610, 615 (D.C. Cir. 1978).
[101] 429 F.2d 232, 234 (8th Cir. 1970).
[102] 10 C.F.R. § 205.371.

"emergency," including one occasioned by a "shortage of electric energy," must be sudden, unexpected, and demanding of "immediate action."

ii. The Order fails to present facts establishing an emergency under section 202(c) or the Department's regulations

Even taken as complete and accurate claims (which they are not), the factual assertions made in the Order fail to describe an "emergency." The Order does not claim that the retirement of J.H. Campbell was sudden or unexpected. Nor could it. The retirement of J.H. Campbell was carefully planned over a period of years and was approved by the MPSC through a public proceeding. Further, Consumers' plan to retire J.H. Campbell included a commitment to procure replacement resources that improved its capacity position. And Consumers' proposal to retire J.H. Campbell was approved in advance by MISO after a thorough review of its impact on reliability.

Nor did the publication of NERC's 2025 Summer Reliability Assessment in May 2025 transform a long-planned retirement into an event with sudden or unexpected implications requiring immediate action. The Order notes that the 2025 NERC Summer Reliability Assessment characterizes MISO as being at an "elevated risk of operating reserve shortfalls." But NERC's "elevated risk" designation in no way signifies an emergency condition. "Elevated risk," it should be emphasized, falls *below* NERC's highest risk designation: that of "high" risk.[103] NERC's decision not to place MISO in the highest risk category in its Summer Reliability Assessment is

[103] The "High" risk designation refers to a risk of shortfall during normal peak conditions, whereas the "Elevated" risk designation refers to a risk of shortfall during above-normal peak conditions. See Attachment A, NERC, 2025 Summer Reliability Assessment at 6.

in itself powerful evidence that there is no "emergency" stemming from a lack of operating reserves.

The "elevated risk" designation is also far from unusual. In the same report, NERC also designated the systems overseen by SPP, the Electric Reliability Council of Texas (ERCOT), and the New England Independent System Operator (ISO-NE) as at "elevated risk."[104] Except for 2022, when it was designated as "high" risk, MISO has been designated as "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[105] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021.[106] In effect, what the Order implies through its reliance on the NERC report's "elevated" risk designation, is that the fifteen states of MISO – along with large swaths in the rest of the United States – have been in an uninterrupted state of emergency for many years on end. This interpretation, if credited, would effectively read the word "emergency" out of section 202(c).

The Order's hand-waving reference to "potential tight reserve margins" identified in the 2025 NERC Summer Reliability Assessment likewise fails to describe an emergency. The very fact that the Order attempts to rely on "potential" future conditions itself contradicts the notion that MISO is presently facing an

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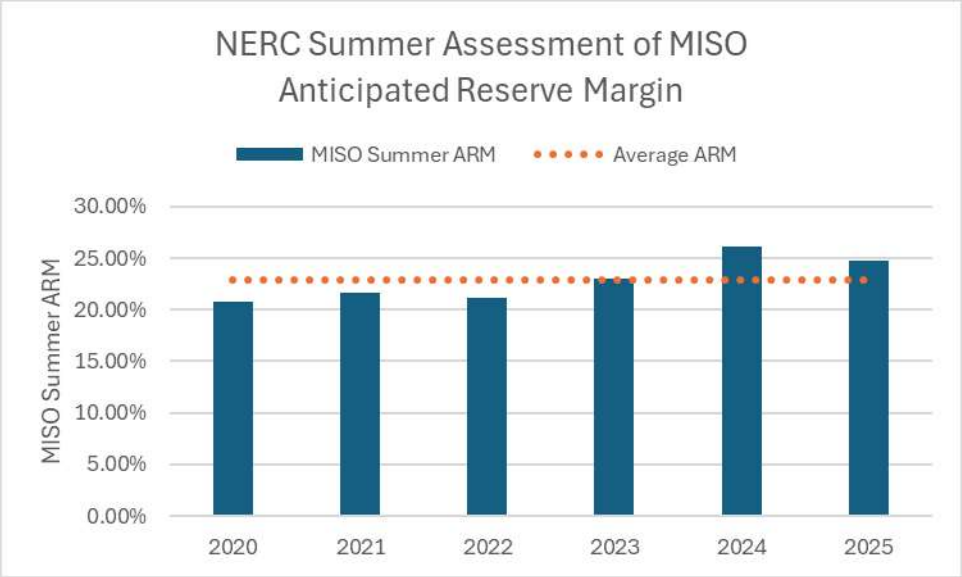
[104] *Id*.

[105] *See* NERC Summer Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

[106] *See* NERC Winter Reliability Assessments years 2021 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

emergency as conceived under section 202(c). Moreover, the actual reserve margins in MISO this summer do not support an emergency determination. The NERC report calculated MISO's anticipated reserve margin for Summer 2025 as 24.7%.[107] This figure substantially exceeds NERC's "Reference Margin Level" for MISO of 15.7%,[108] which is the level that NERC has "established for the areas to meet resource adequacy criteria."[109] MISO's anticipated reserve margin of 24.7% is also *higher* than its average of recent years. The chart below shows the anticipated reserve margin for MISO as calculated in the NERC Summer Reliability Assessment for each year.[110] The chart shows that the 2025 anticipated reserve margin of 24.7% exceeds the 2020-2025 average of 22.9%. Again, the Order has failed to describe a circumstance that is "unexpected," "sudden" or "demanding of immediate attention."



[107] Attachment A, NERC, 2025 Summer Reliability Assessment at 10.
[108] *Id*. at 44.
[109] *Id*. at 15.
[110] *See* NERC Summer Reliability Assessments years 2020 – 2025, available at https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

The other factual assertions in the Order likewise fail to describe an emergency. The Order devotes one of its few substantive paragraphs to explaining that various generation units have retired in Michigan, reaching back as far as 1997.[111] But generation units retire everywhere as part of the normal, continuous cycle through which old units are replaced with new ones. The unsurprising fact that generation units have retired in Michigan over the last 28 years says nothing about whether there is presently adequate generation in the State, and even less about whether an emergency exists in the region as a whole.

The Order then points to the results of the April 2025 MISO Planning Resource Auction. But these results explicitly contradict the claim that an emergency exists in MISO. The Order acknowledges MISO's conclusion that the auction "demonstrated sufficient capacity." In fact, the Order truncates this quote, which stated in full that: "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."[112] Remarkably, the Order attempts to brush aside the obvious import of this conclusion, preferring instead to focus on the second half of the sentence. But the second half of that sentence merely refers to the fact that the summer price for capacity in MISO, which separates the auction results by season, is high*er* and has a tight*er* supply/demand balance than those of the fall, winter and spring seasons (a fact illustrated by the chart below the header text).

[111] Order at 1.
[112] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 12.

This sentence does not indicate any kind of shortfall in the summer season, much less an emergency shortfall.

The Order also quotes from a slide that states "for North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[113] But this slide is simply noting that the total capacity of resources *offered* into the 2025 auction in the North/Central region was lower than what was offered into the 2024 auction. This slide does not say that the total amount of capacity *procured* in the North/Central region through the auction was inadequate. In other words, this slide is in no way inconsistent with the conclusion in the same report that the "2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels."[114] Further, even as a characterization of the total capacity offered into the auction, the Order ignored a crucial fact in this slide. The slide shows that the reason for the decrease in capacity offered was not because of a decrease in physical generating capacity, but because of a change in the capacity accreditation of various resources—most notably, the very "dispatchable generation" that the order prioritizes. This change in MISO's capacity accreditation methodology occurred over the previous year.[115] The bar chart in Attachment B shows a reduction in accredited capacity for gas and coal of 3.4 GW, which is greater than the overall reduction in offered

[113] *Id*. at 13.
[114] *Id*. at 12.
[115] *Midcontinent Independent System Operator, Inc*., 189 FERC ¶ 61,065 (Oct. 25, 2024).

capacity.[116] In other words, MISO concluded that coal (and gas) resources, such as J.H. Campbell, should be deemed to contribute less to capacity requirements than it had previously assumed.

B. Abusing an Authority Meant for True Emergencies, the Order Intrudes on Authority Reserved to States and to Other Federal Regulators.

i. Resource adequacy is regulated by the states, and by FERC under other provisions of the Federal Power Act

Resource adequacy refers to the capacity of an electric power system to meet demand reliably at all times, including during system peaks and through potential outages. Resource adequacy is "measured at the system level to capture the overall impact of outages of individual components including generators and transmission."[117] Resource adequacy planning is the process by which utilities and system operators, under regulatory supervision, ensure resource adequacy. Resource adequacy planning involves technical and economic considerations that go into determining what resources are added to the grid and which resources should retire and when.

With respect to regulatory oversight for resource adequacy, section 201 of the FPA, 16 U.S.C. § 824(b)(1), reserves authority over generation facilities to the states. It states in pertinent part: "The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over*

[116] Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 13.
[117] NREL, Resource Adequacy Basics, available at https://www.nrel.gov/research/resource-adequacy.

facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[118]

Some states have retained this authority over resource adequacy in its entirety.[119] Others have directed their utilities to join RTO/ISOs that, through their tariffs, impose resource adequacy requirements. Those RTO/ISOs also generally establish markets that allow market participants to buy and sell capacity and thereby to facilitate market entry and exit decisions based on price signals. Resource adequacy requirements in RTO/ISO tariffs have been held to be practices affecting wholesale rates subject to the jurisdiction of FERC under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d & 824e.[120]

In Michigan, the regulation of resource adequacy planning has both a state and federal aspect. As a member of MISO, Consumers has a capacity obligation under the MISO tariff. MISO's resource adequacy requirements, however, are designed to be complementary to the primary role of the states in ensuring resource adequacy.[121]

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[118] *Id*. (emphasis added).

[119] *See Devon Power LLC et al.,* 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[120] *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).

[121] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, 62,606 at P 13 (2020) ("approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities ... within the [MISO] region."); *see also id*. ("MISO's proposed Tariff language

Consumers' investment decisions are regulated by the MPSC. Through the state IRP process (described in Section II.C above), the MPSC exercises regulatory authority over Consumers in order to ensure that the utility obtains the amount of capacity it needs to meet its obligations under the MISO tariff, and that it does so at the best value to ratepayers, and with a composition of resources that otherwise complies with state law, including state environmental requirements.

ii. Section 202(c) does not vest DOE with general regulatory authority over resource adequacy

The Order indicates that the Department believes it has the authority to decide which power plants may retire and when, not based on the kind of real emergency that has justified past action, but rather based on its own policy preferences. The Department appears to want to place its own judgment about operating reserve margins ahead of MISO's, and its own preference for which resources are employed to maintain resource adequacy ahead of Michigan's. In effect, the Department appears to read section 202(c) so as to give itself authority to regulate resource adequacy. Any ambiguity on this point was put to rest by the Department's June 13 letter referring cost recovery issues for J.H. Campbell to FERC. In that letter, the Department, through counsel, acknowledged that resource adequacy concerns

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explains that the resource adequacy requirements 'are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction.' In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's Auction is not—*and has never been*—the primary mechanism for its [Load Serving Entities] to procure capacity."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]").

motivated the Order and went so far as to purport to dictate whether J.H. Campbell would be counted as a capacity resource pursuant to the MISO tariff.[122]

Section 202(c) does not provide the Department with the authority it claims. Had Congress intended to vest regulatory authority over resource adequacy in section 202(c), – displacing both state law and sections 205 and 206 of the Federal Power Act, – it would have stated so clearly. But of course it did not. The authorizing language says no more than that DOE may "require by order . . . such generation . . . of electric energy as in its judgment will best meet the emergency and serve the public interest." Indeed, it defies logic that, had Congress intended to empower DOE to be the general decider of which power plants may retire across every utility and independent power producer across the entire country – a function with profound implications for rates, state sovereignty, and a broad array of other stakeholder interests – that Congress would have done so through what may be the only provision in the Federal Power Act that empowers the regulator to act without first assessing the effect on ratepayers or seeking public input, and one of the only provisions that extends to otherwise non-jurisdictional utilities such as public power entities and those in ERCOT.

But even if the text of section 202(c) could, theoretically, be stretched to such an expansive reading (which it cannot), the United States Supreme Court has emphatically rejected statutory interpretations whereby an agency "claim[s] to discover in a long-extant statute an unheralded power representing a transformative

[122] FERC Docket No. EL25-90, submission of Dep't of Energy, June 13, 2025 ("Because the May 23, 2025 Order is predicated on the shortage of facilities for the generation of electric energy and other causes, such as resource adequacy concerns, the Campbell plant shall not be counted as a capacity resource.").

expansion in its regulatory authority."[123] That is exactly what the Department seeks to do here. It seeks to discover in a 90-year-old statute a basis to exercise much broader regulatory authority than it ever has in the past. While it is true, as we explain above in section II.A, that the Department has used section 202(c) to delay power plant retirements on three occasions over the 90-year history, it has always done so at the request of a system operator or governmental body and in a manner narrowly tailored to prevent a concrete and particularized emergency. It has never done so simply to impose its policy preferences ahead of the judgment of those bodies responsible for resource adequacy.

C. The Order Fails to Present Substantial Evidence for its Emergency Determination and Fails to Exercise Reasoned Decision-making by Ignoring Critical Facts.

The Order relies on three sources of evidence for its emergency determination: the NERC 2025 Summer Reliability Assessment, generator retirements in Michigan, and the results of MISO's 2025 Planning Resource Auction. None of these three sources provide evidence that an emergency exists. By relying on these sources, and by misconstruing each of them, the Order fails to exercise reasoned decision-making.

The Order also entirely ignores several other critical facts and considerations. The Order ignores the fact that MISO approved the deactivation of J.H. Campbell. The Order ignores the conclusions of the MPSC proceeding that approved the retirement of J.H. Campbell. And even if it were correct that a capacity shortfall

[123] *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724–25, (2022) (quoting *Util. Air Regul. Grp. v. E.P.A.*, 573 U.S. 302, 324 (2014))(internal quotations omitted).

exists in MISO, the Order fails to explain why preventing the retirement of J.H. Campbell through an emergency measure is necessary to address the shortfall.

i. The Order's discussion of the NERC 2025 Summer Reliability Assessment is unreasoned and incomplete

As explained above in Section IV.A, the Order's discussion of the NERC 2025 Summer Reliability Assessment is both incomplete and unreasoned. Specifically, the Order fails to explain (i) why the NERC report supports an emergency finding for MISO given that NERC did not put MISO in the "high" risk category, (ii) why NERC's designation of MISO as at "elevated" risk provides evidence of a "sudden" or "unexpected" circumstance given that MISO has been at this risk level or higher for years running, and (iii) why the "potential tight reserve margins" identified in the NERC report constitute an emergency given that MISO well exceeds the NERC reference margin level and even exceeds its own average Summer anticipated reserve margin over the 2020 – 2025 period.

ii. The Order's apparent reliance on generator retirements in Michigan is unreasonable

The Order attempts to support its emergency finding by recounting the fact that various power plants have retired in the state of Michigan.[124] As explained above, because power plant retirements are a regular occurrence in the electric power sector, the Order's discussion of this topic fails to present even *prima facie* evidence of an emergency. It also fails to exhibit reasoned decision-making in two key respects. First, it is unreasonable to point to capacity retirements in isolation

[124] Order at 1.

without also considering all the other factors that contribute to resource adequacy. Such factors include capacity additions, changes in load, load shape and load flexibility, demand response, transmission access to external resources, etc. Of course, MISO *did* consider all those factors in the modeling that went into the Attachment Y process through which it approved the deactivation of J.H. Campbell.[125]

Second, the Order fails to explain how power plant retirements in Michigan are related to the emergency the Department purports to identify. In past orders where the Department has used section 202(c) to delay a power plant's retirement, the Department has acted on application of a utility or system operator to address a discrete, localized emergency that would be caused by the impending retirement.[126] The Department makes no such claim to geographic specificity here. Rather, the remainder of the "Emergency Situation" section of the Order appears to describe a purported emergency throughout MISO, insofar as it relies on NERC's general statements about MISO reserve margins and the results of the MISO Planning Resource Auction. Thus, the Order fails to explain why it is relying on power plant retirements in a single state—Michigan—to support its claim that an emergency exists in the region as a whole.

iii. The Order acknowledges that the most recent MISO auction "demonstrated sufficient capacity" but fails to explain why an emergency exists nonetheless

[125] *See* MISO Transmission Planning Business Practices Manual, BPM-020-r32 Section 6.2 (Generator Retirement and Suspension Studies and System Support Resources), Section 6.2.3 (Study Scope Development).
[126] *See* Section II.A *supra*.

As explained in Section IV.A above, the Order cites to the MISO planning reserve auction report while ignoring the statement in that report that: "The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels." It is entirely unreasonable for the Department to cite this report as evidence of an emergency when the report has concluded exactly the opposite. The Order's effort to focus on other aspects of the report are equally unreasonable. The unremarkable statement that summer prices are higher than prices in other seasons and therefore reflect a tighter supply/demand balance falls far short of providing evidence for an emergency. Likewise, the Order's reliance on the fact that less capacity was *offered* in the 2025 auction than was offered into the 2024 auction hardly describes an emergency. Further, the Order fails to note the information conveyed in the slide it quotes from, which shows that the only material change between 2024 and 2025 was a result in a change in capacity accreditation values rather than a change in physical resources available.

iv. The Order fails to acknowledge that MISO approved the retirement of J.H. Campbell

As explained in Section II.C above, after a robust, technical, and considered process, MISO approved the retirement of the three J.H. Campbell units pursuant to the study process governed by its tariff. MISO concluded that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria." As the system operator, MISO has more in-depth knowledge of its system than the Department does. The Department should have explained why it reached a

different conclusion than MISO. Instead, the Order failed even to mention that MISO conducted this study and approved the retirement.

v. The Order makes no effort to review the findings of the MPSC or to demonstrate consultation with Michigan as required by 42 U.S.C. § 7113

The Order acknowledges that Consumers acquired the Covert gas plant, but in all other respects fails to acknowledge the MPSC proceeding that approved Consumers' IRP settlement entailing retirement of J.H. Campbell. As explained above in Section II.C, acquiring the Covert gas plant was not the only action Consumers took as part of that IRP. The IRP also delayed the retirement of the peaking units at the Karn facility and included the acquisition of other new resources, with the result that Consumers' capacity position was set to improve materially even after the retirement of J.H. Campbell. The Order also ignores the Michigan capacity demonstration proceedings that found both Consumers and MISO Zone 7 have sufficient capacity resources in 2025 and in the years to come.

Section 103 of the Department of Energy Organization Act, 42 U.S.C. § 7113, provides:

> Whenever any proposed action by the Department conflicts with the energy plan of any State, the Department shall give due consideration to the needs of such State, and where practicable, shall attempt to resolve such conflict through consultations with appropriate State officials.

The Order plainly conflicts with Michigan's energy plan, as reflected in the MPSC's approval of Consumers' IRP. Equally clearly, the Order does not give "due consideration" to the needs of Michigan. Nor does it appear that the Department

made any attempt to resolve the conflict it created through consultation with the appropriate State officials. The Department, therefore, has failed to comply with Section 103 of the Department of Energy Organization Act. A practical consequence of the Department's apparent failure to consult with the State is that the Order lacks basic information related to its action, including the Order's inexplicable failure to accurately state the capacity of J.H. Campbell, the lack of awareness as to the operational status of Unit 2, the understatement of resources Consumers acquired to replace J.H. Campbell, and the omission of any reference to the reliability analysis undertaken by the State.

vi. The Order fails to provide any specific evidence or reasoning why J.H. Campbell must remain in operation and why alternative measures are inadequate

Even accepting the Order's contention that there exists a capacity shortfall in MISO, it does not follow that commanding the continued operation of J.H. Campbell is the best or even an appropriate means of alleviating the shortfall. The Order does not assert that there is a local problem on the grid that only J.H. Campbell can solve. In this respect, the Order departs markedly from past uses of section 202(c) and from the Department's regulations implementing section 202(c), which state that: "Actions under this authority are envisioned as meeting a specific inadequate power supply situation."[127]

Rather, the emergency that the Order purports to identify – "potential tight reserve margins" – is one that spans the entire fifteen-state MISO region and one

[127] 10 C.F.R. § 205.371.

that could presumably be addressed by any number of actions across MISO. And, given that J.H. Campbell amounts to well less than 1% of generation capacity in MISO, there likely were options available that would have had a much greater impact on the overall balance of supply and demand. Further, because J.H. Campbell is an over 60-year-old facility in a largely degraded operational state, there presumably were alternative actions available that could have met the purported need with higher levels of reliability.

Yet the Order does not acknowledge any alternatives or explain whether less burdensome measures were exhausted before taking this action. The question of whether alternative measures could have been used to address the "emergency" is made more challenging by the fact that the Order never quantifies the extent of the emergency it purports to identify within MISO. But that omission merely highlights rather than excuses the deficiencies of the Order.

One possible alternative may have been demand-side measures. The Department's regulations require applicants seeking an order under section 202(c) to provide a "description of any conservation or load reduction actions that have been implemented . . . [and a] discussion of the achieved or expected results."[128] In the Yorktown case, the Department required Dominion to exhaust all demand response measures before dispatching the facility.[129] And yet here the Department failed to make any inquiry or even to consider whether demand-side measures could have

[128] 10 C.F.R. § 205.373.
[129] *See* DOE Order No. 202-17-4 (Sept. 14, 2017) ("PJM and Dominion shall exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Unit 1 or Yorktown Unit 2.")

addressed the purported emergency. Similarly, the Department's regulations require applicants to describe their efforts made to obtain additional power through third parties.[130] But again, the Department failed to consider whether MISO could alleviate the purported emergency through access to external resources.

D. The Department's Direction that MISO Operate J.H. Campbell Using "Economic" Dispatch Is Inconsistent with its Authority under Section 202(c).

The Department's Order directs MISO to "take every step to employ economic dispatch of the Campbell Plant."[131] The Order indicates that the use of economic dispatch is intended to "minimize cost to ratepayers."[132] However, this mandate to MISO exceeds the authority provided by section 202(c). Nor is the use of economic dispatch likely to serve the public interest.

The Order does not define "economic dispatch" or specify how it intends MISO to dispatch the units. In the Energy Policy Act of 2005, Congress adopted a definition of "economic dispatch" that generally conforms to accepted use: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[133] Drawing on this statutory definition, FERC issued a 2006 report, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations,* that provides a useful explanation of the 2-step process that

[130] 10 C.F.R. § 205.373(h).
[131] Order at 2 (Ordering Paragraph A)
[132] *Id.*
[133] *See* section 1234(b) of the Energy Policy Act of 2005, 42 U.S.C. § 16432(b);

regions have, in practice, adopted to implement economic dispatch.[134] This process includes (1) *day ahead unit commitment*, in which grid operators commit generators to be online in the subsequent 24-hour period, determined based on which generators will be most economic, taking into account each unit's physical operating characteristics, and (2) *unit dispatch*, in which grid operators dispatch committed resources at specified levels, in real-time, determined based on what set of units will minimize total system costs, given actual load, generation, and transmission conditions and constraints.[135]

Section 202(c) authorizes DOE to direct certain actions during emergency conditions. As relevant here, section 202(c)(1) provides DOE with "authority . . . to require by order . . . such generation . . . of electric energy as in its judgment will *best meet the emergency* and serve the public interest." In other words, DOE's power extends only to ordering actions that meet the emergency that the Department has identified.

But economic dispatch is not a rational response to the types of emergencies that section 202(c) authorizes DOE to address. Nor would economic dispatch be a rational approach to addressing the circumstance that DOE is purporting to address with its order—a potential capacity shortfall—if that were within its authority under section 202(c). In fact, DOE has made no effort to explain why economic dispatch is a rational remedy here, — let alone the best means of meeting the "emergency" that it

[134] FERC, *Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations* (July 31, 2006), https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.
[135] *Id.* at 5-6.

has identified. And, unlike prior Orders, here DOE acted on its own motion without a request or input of MISO and so cannot rely on the expertise of the cognizant grid operator or operating utility requesting a specific remedy to justify the appropriateness of economic dispatch.[136]

i. Economic dispatch is not a rational response to a shortage of electric energy

Economic dispatch is the standard procedure by which operators (such as MISO) operate the grid. However, outside of normal operations, including during emergency conditions, generation units may be selected "out of merit order" as necessary to ensure that generation and load are balanced. Operating a unit pursuant to economic dispatch is, necessarily, inconsistent with operating the unit in a manner designed to address an emergency, such as a shortage of electric energy. If a unit would be dispatched under purely economic conditions, but electric demand can alternatively be met with other existing supply (or demand response) resources, that unit is *not* necessary to meet the emergency. However, if the unit would, in fact, be needed to address a shortage, it should be dispatched regardless of whether its offer price is above or below the market-clearing price. In other words, economic dispatch is not a dispatch rule that is reasonably tailored to ensure that the unit addresses a shortage of electric energy.

[136] *See* DOE Order No. 202-18-1 at 4 (The statute requires only that the Secretary use his or her best judgment to meet the emergency and serve the public interest. In this situation, the expertise of the applicant was an important factor. The Department received an application from PJM, which . . . holds the highest-level, federally-regulated reliability responsibilities for the system it manages.), https://www.energy.gov/sites/prod/files/2017/11/f46/Summary%20of%20Findings%20Order%20No.%202-18-1.pdf.

Prior DOE orders have contained significant operating constraints to satisfy this statutory requirement. Orders have specified that units subject to a section 202(c) order should only run in specific emergency alert conditions — specific conditions in which grid operators have exhausted the capacity of other available generators, imports, and voluntary demand response, and failure to call on additional generation will risk involuntary load shed.[137] Similarly, in its order to delay retirement of the Yorktown plant, DOE recognized that dispatch of the units must be constrained, that continued operation of the units under the standard methodologies used by the local utility (Dominion Energy Virginia) and grid operator (PJM) would not be appropriate, and that Dominion and PJM must exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2.[138] Similarly, in the case of its 2005 District of Columbia Department of Public Service order, the Department directed Mirant to maintain its facility's capacity to respond when needed, but only ordered it to run when one or both of the 230 kV transmission lines serving downtown D.C. were out of service.[139] And in its 2017 order regarding GRDA's Grand River Energy Center

[137] DOE Order No. 202-21-1 (authorizing operation only during Energy Emergency Alert Level 2 or Level 3); DOE Order No. 202-21-2 (authorizing operation only during Energy Emergency Alert Level 2 or higher); DOE Order 202-22-1 (same); DOE Order No. 202-22-3 (same); DOE Order No. 202-22-4 (same).

[138] DOE Order No. 202-17-2 (providing that Yorktown units 1 and 2 may be dispatched "only when called upon to address reliability needs" and directing PJM and Dominion Energy Virginia "to provide the dispatch methodology to the Department upon implementation, and to report all dates on which Yorktown Units 1 and 2 are operated"); DOE Order No. 202-18-1 at 3 (relying on the fact that DOE "require[d] PJM and Dominion to exhaust available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Units 1 or 2").

[139] DOE Order No. 202-05-3 (Dec. 20, 2005), District of Columbia Public Service Commission at 10 – 11.

Unit 1, the Department strictly limited its remedy, directing GRDA only to provide "dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes."[140] DOE's Order contains no such constraints, and it fails to explain or justify such deviation from consistent past practice.

ii. Economic dispatch is an arbitrary response to any alleged capacity shortage

Indeed, even on DOE's own terms, the justification for the Order does not support ordering J.H. Campbell to operate whenever MISO's economic dispatch rules would select it to operate. The Order points specifically to questions about the sufficiency of electric *capacity* and the ability of MISO to meet load during periods of high demand and low resource output over the next 90 days as the basis for its emergency determination.[141] For example, the Order points to NERC's 2025 Summer Reliability Assessment, and specifically to the finding that "MISO is at elevated risk of operating reserve shortfalls *during periods of high demand and low resource output*."[142] The order repeatedly raises concern about the risk of "*capacity* shortfall for MISO," the extent to which *capacity* of certain generating resources have retired or may retire, and that MISOs' *capacity* market auction (the Planning Resource Auction Results for Planning Year 2025-26) "reinforce the need to increase *capacity*."[143] Dispatch of J.H. Campbell at any time other than a specifically identified operating reserve shortfall (e.g., a concrete expected supply/demand imbalance)—let

[140] DOE Order No. 202-17-1 at 2.
[141] Order at 1-2
[142] Order at 1 (emphasis added).
[143] Order at 1-2.

alone dispatch whenever the plant would be called upon by MISO's economic dispatch algorithm—is *not* necessary to address the type of emergency that the DOE order identifies. Even if the order sufficiently justified retention of J.H. Campbell as a capacity resource (which it does not for the reasons outlined above), it would not follow that J.H. Campbell's electric *energy* is needed to address the identified emergency. Given the nature of the alleged emergency identified in the Order, no dispatch from J.H. Campbell should be necessary unless and until called upon by MISO expressly to address an emergency purpose.

iii. "Economic dispatch" is not in the public interest in this case

Section 202(c) also requires that DOE determine that a given remedy is in the public interest.[144] The public interest determination is not an independent or sufficient criteria to order any particular action. Rather, Congress's use of the conjunctive "and" in section 202(c)(1) clearly prohibits DOE from ordering actions that the Department believes will advance the public interest if those actions exceed what is needed to address the identified emergency. In fact, DOE acknowledged this limit on its authority in its order denying rehearing of its order directing the retention of the Yorktown power plant.[145] Therefore, for the reasons explained above, economic dispatch is not appropriate even *if* DOE determines that it would advance the public interest.

However, DOE's vague direction to MISO to operate Campbell using "economic dispatch" will not further the public interest. DOE's order does not explain why it

[144] 16 USC § 824a (c)(1).
[145] DOE Order 202-18-1 at 4.

believes economic dispatch would be in the public interest, other than a general reference to "minimize[ing] cost to ratepayers." However, this justification fails for two reasons. First, the Order's reference to economic dispatch is ambiguous and leaves open the likelihood that Consumers will operate the facility even at times when its operation will have the effect of *increasing* costs to consumers. For example, Consumers is likely to commit J.H. Campbell into MISO's day ahead electricity market as a "must run" unit, rather than using Emergency commitment.[146] In other words, Consumers will operate the units at least at minimum load every day rather than when there is a forecasted shortfall (e.g., due to unexpected load, unit outage, or a natural disaster). In such circumstances, J.H. Campbell will run at its minimum operational level regardless of whether doing so is truly economic. As a result, DOE has not justified, and cannot be reasonably certain, that economic dispatch will "minimize cost to ratepayers" — its sole explanation for the operational profile it has directed MISO to adopt. In other words, DOE's ordering of economic dispatch in this case is arbitrary.

Moreover, by directing economic dispatch, rather than reserving J.H. Campbell for discrete supply shortages by committing it as Emergency status, DOE's order will result in the facility operating significantly more than necessary. Because J.H. Campbell is old, and because Consumers has been deferring maintenance in anticipation of its retirement, a significant step-up in operation caused by must-run commitment and economic dispatch will increase the likelihood that one or more

[146] *See* MISO Tariff, Section 39.2.5.b.xxvi (discussing Emergency Commitment Status).

units break, requiring costly maintenance to continue operating. Such repairs would likely further increase costs to ratepayers—costs that would be less likely to occur under an operational order better tailored to the emergency that DOE has identified. For example, DOE could have minimized the risk of ratepayer costs had it directed Consumers and MISO to commit (and ultimately dispatch) the facility only after analysis showing a likely near-term supply/demand imbalance or short-term emergency conditions (such as a heatwave, or the forced outage of a large generator or transmission line). The Order is arbitrary and capricious by ordering operation that risks increasing costs to ratepayers, the very outcome DOE has said it is looking to avoid.

Second, the Order fails to consider, let alone explain away, the fact that the State of Michigan has made an independent judgment that it would be in the best interest of ratepayers, the state, and the environment, to accept Consumers' proposal to retire J.H. Campbell. As explained above, the State of Michigan and MISO each went through robust processes to assess the need for J.H. Campbell (or lack thereof), as well as the economic and environmental impacts of its continued operation. The State of Michigan appears not to have been consulted on DOE's Order, notwithstanding the extensive process that it underwent to evaluate whether retirement would be in the public interest. Here, the public interest is best effectuated by respecting the Michigan's considered decision to approve the closure of J.H. Campbell plant, rather than to allow its near continuous operation at ratepayer expense.

Finally, for the reasons explained more fully below, the Order fails to consider the increased air and water pollution that will be caused by J.H. Campbell operating pursuant to economic dispatch instructions. DOE fails to even consider these harms, let alone weigh them against the (alleged) benefits of increased operation, in its determination that economic dispatch of the J.H. Campbell plant will further the public interest.

E. The Department failed to limit its remedy as required by 202(c)(2).

Section 202(c) imposes strict substantive limits on the Department's authority to issue emergency orders that may result in conflicts with any Federal, State, or local environmental law or regulation. Congress deliberately included these limitations to prevent section 202(c) from becoming a de facto exemption from environmental regulation. Here, DOE failed to comply with either of the statute's two express constraints and therefore acted unlawfully.

i. Section 202(c)(2) contains two distinct and binding legal constraints

Congress imposed two critical limitations on the scope of a DOE emergency order under section 202(c):

Temporal Constraint. First, DOE must "ensure that such order requires generation . . . of electric energy only during hours necessary to meet the emergency and serve the public interest."[147] Again, this is a conjunctive requirement such that both conditions—operation in a given hour must be necessary to meet the emergency

[147] 16 U.S.C. § 824a(c)(2).

and operation in a given hour must serve the public interest—must be satisfied.[148] Moreover, by referring to the "hours" necessary to meet the emergency, Congress placed a high burden on DOE to demonstrate that the remedy provided was narrowly tailored to the specifics of the emergency that the order is designed to address.

Environmental Constraint. Second, the Department must "ensure that such order . . ., to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts."[149]

The Department acknowledges that, "additional generation may result in a conflict with environmental standards and requirements" and so it is required to limit additional generation from J.H. Campbell. However, the Order then wholly fails to meet the acknowledged temporal and environmental constraints in the particular ordering conditions that it establishes.

ii. The Order violates Section 202(c)(2)'s temporal constraint

The Order states that its direction to Campbell is "limited in duration to align with the emergency circumstances."[150] But, in fact, DOE has directed the unit to operate for the entire statutory maximum of 90 days. And, as described in more detail *supra,* within that 90-day window, DOE has directed the use of "economic dispatch"—an operational direction that will likely result in Campbell operating at least at its

[148] DOE Order No. 202-18-1, 4(Nov. 6, 2017).
[149] 16 U.S.C. § 824a(c)(2).
[150] Order at 2.

minimum output level, and more likely at the maximum output Consumers Energy can manage, taking into account the state of the facility, continuously for the 90-day period—without providing any other temporal limitation on operations. In other words, the Order appears to assume, without explanation, that an emergency will exist in every hour over the entire 90-day period of the Order that Consumers happens to submit a bid into MISO's energy auction that is lower than the market-clearing price.[151] There is no reason to expect that this will actually be the case.

For these and all the reasons explained in section IV.C, the Order's direction that MISO dispatch J.H. Campbell economically is flatly inconsistent with section 202(c)'s requirement that emergency orders be limited to "only" those "hours" in which operation is necessary to meet the emergency. DOE cannot transform an hour-by-hour limitation into a blanket summer-season waiver through hand-waving at "elevated risk" of tight operating reserves and "*potential* electricity shortfalls."

DOE's failure to limit dispatch to discrete periods when the generation is needed to address the purported emergency renders the Order unlawful under the plain terms of § 202(c).

iii. The Order violates section 202(c)(2)'s environmental constraint

Section 202(c)(2) also requires DOE to ensure, "to the maximum extent practicable," that its orders (1) are consistent with applicable environmental laws and

[151] In fact, it is not clear that DOE will limit operation to 90 days. DOE is authorized to extend the Order beyond 90 days under section 202(c), 16 U.S.C. § 824a(c)(4)(A), and has made no representation that the "emergency" is likely to be resolved by the end of the 90-day period.

regulations and (2) "minimize any adverse environmental impacts." The Department makes no serious effort to comply with this mandate.

First, the Order contains no analysis of J.H. Campbell's environmental obligations. J.H. Campbell is subject to air pollution requirements limiting its emissions of SO_2, NO_x, particulate matter, and mercury, and mandates the use of pollution control equipment such as baghouses, dry sorbent injection, and activated carbon injection systems.[152] DOE does not reference these requirements, direct Consumers to optimize the use of pollution controls or avoid operation during air quality episodes (even if those episodes occur at a time when the marginal energy from J.H. Campbell is not needed to meet electric demand), or provide any guidance for how Consumers is to operate the facility in the event that these requirements would come in conflict with its ability to provide power at any given time. It does not clarify what steps Consumers Energy would have to take to ensure continued operation of pollution control equipment in the event such equipment malfunctioned during the 90-day period. Nor does it appear the Department consulted with the State of Michigan, including its environmental regulator, to identify mechanisms to allow J.H. Campbell to remain available in a way that would minimize conflicts with state environmental laws, which the State was uniquely positioned to advise on and which

[152] *See* Michigan Department of Environment, Great Lakes, and Energy, Renewable Operating Permit Issued to Consumers Energy, J.H. Campbell Generating Complex [J.H. Campbell ROP] (July 2, 2021), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal, and also accessible at https://www.egle.state.mi.us/aps/downloads/rop/pub_ntce/B2835/B2835%20FINAL%2007-01-21.pdf.

is required by section 103 of the Department of Energy Organization Act.[153] Instead, the Order offers only generic language about "compliance with applicable requirements… to the maximum extent feasible."

Second, the Order does not establish any operational criteria to "minimize any adverse environmental impacts" as required by section 202(c)(2). This requirement is in addition to the direction to minimize conflicts between operations and environmental requirements. It makes clear that Congress intended DOE to go beyond just avoiding regulatory conflicts but to proactively consider the environmental impact of its emergency orders. But DOE did not design its order to minimize environmental impacts of continued operation of J.H. Campbell. In fact, DOE's order runs directly contrary to the objective of minimizing environmental impacts by expressly directing MISO to operate J.H. Campbell on an "economic dispatch" basis. That instruction prioritizes low-cost dispatch irrespective of environmental impact.

F. The Order Violates NEPA.

Orders issued under section 202(c) are major federal actions subject to NEPA.[154] Such orders direct federal interventions that may affect environmental conditions. The direction to continue operation of J.H. Campbell is unquestionably a major action that significantly affects the environment. Continued operation of J.H. Campbell will result in significant increases of air and water pollution compared to a

[153] *See* 42 U.S.C. § 7113.
[154] 42 U.S.C. § 4336e(10) (defining a "major federal action" as one in which the agency carrying out such action determines subject to substantial Federal control and responsibility.").

scenario in which Campbell retired as planned.[155] In fact, the Order directly concedes this point, stating "the additional generation may result in a conflict with environmental standards and requirements."[156]

For any DOE action affecting the quality of the environment, DOE must comply with NEPA—including through issuance of an environmental impact statement, environmental assessment, categorical exclusion, or special environmental analysis.[157] DOE has not taken, or even initiated, any such action. As such, it is acting contrary to its own NEPA regulations and to its obligations under NEPA.

DOE has previously sought to comply with NEPA for section 202(c) orders through categorical exclusions or special environmental assessments. Neither have been undertaken in this instance. Moreover, neither would be applicable here.

DOE has previously pointed to categorical exclusion B4.4 for "power management activities." However, that categorical exclusion is applicable only "provided that the operations of generating projects would remain within normal operating limits." Here, the Order explicitly authorizes the J.H. Campbell plant to operate beyond its normal permitted limits. Consequently, neither categorical exclusion B4.4, nor any other available exclusion, applies.

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[155] *See* J.H. Campbell ROP, *supra* n. 152; State of Michigan Department of Environmental Quality, Authorization to Discharge Under the National Pollutant Discharge Elimination System, Permit No. MI0001422 (May 29, 2018), accessible through the Michigan Department of Environment, Great Lakes, and Energy's "MiEnviro Portal," https://www.michigan.gov/egle/maps-data/mienviroportal.
[156] Order at 2.
[157] *See* 10 C.F.R. § 1021.102(b).

More recently, DOE has, on certain occasions, relied on emergency provisions that can excuse agencies from preparing environmental documents before taking such actions,[158] and instead prepared after-the-fact Special Environmental Analyses in the event that an order results in a significant effect on the environment.[159] However, these instances involved sudden emergencies that provided DOE substantially less notice compared to the months or years of advance warning DOE received regarding J.H Campbell's scheduled retirement. In this case, DOE acted in response to circumstances known well in advance: the long-scheduled retirement of J.H. Campbell on May 31, 2025. Given considerable lead time, DOE had ample opportunity to prepare, at a minimum, an EA prior to issuing its Order. DOE's failure to initiate any environmental review thus lacks justification.

Moreover, there will be even less justification for a failure to initiate appropriate environmental review for any extension of the Order beyond the initial 90 days. Under section 202(c)(3), orders conflicting with environmental laws are strictly limited to 90 days but may be extended. However, such extension requires consultation with other federal agencies responsible for regulating or with expertise in such environmental impacts.[160] Any justification that NEPA can be sidestepped to

[158] *See* 10 C.F.R. § 1021.343(a); 40 C.F.R. § 1506.12.
[159] *See* DOE, Air Quality and Environmental Justice Memorandum (2021), https://www.energy.gov/sites/default/files/2022-01/sea-05-ercot-air-quality-and-ej-analysis-2021-07-21.pdf; DOE, Special Environmental Analysis for Actions Taken Under U.S Department of Energy Emergency Orders Regarding Operation of the Potomac River Generating Station in Alexandria Virginia (2006), https://www.energy.gov/sites/default/files/nepapub/nepa_documents/RedDont/SEA-04-2006.pdf
[160] 16 U.S.C. § 824a(c)(4)(B).

address an emergency need fades as DOE's orders extend beyond the initial 90-day period.

V. CONCLUSION

For the foregoing reasons, the Michigan Attorney General's request for rehearing should be granted.

Dana Nessel
Michigan Attorney General

Michael E. Moody

Digitally signed by Michael E. Moody
Date: 2025.06.18 16:14:42 -04'00'

Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

Dated: June 18, 2025

Attachment A

2025 NERC Summer Reliability Assessment

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025

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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is spans six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA*), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA*. Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's 2024 *State of Reliability* report

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

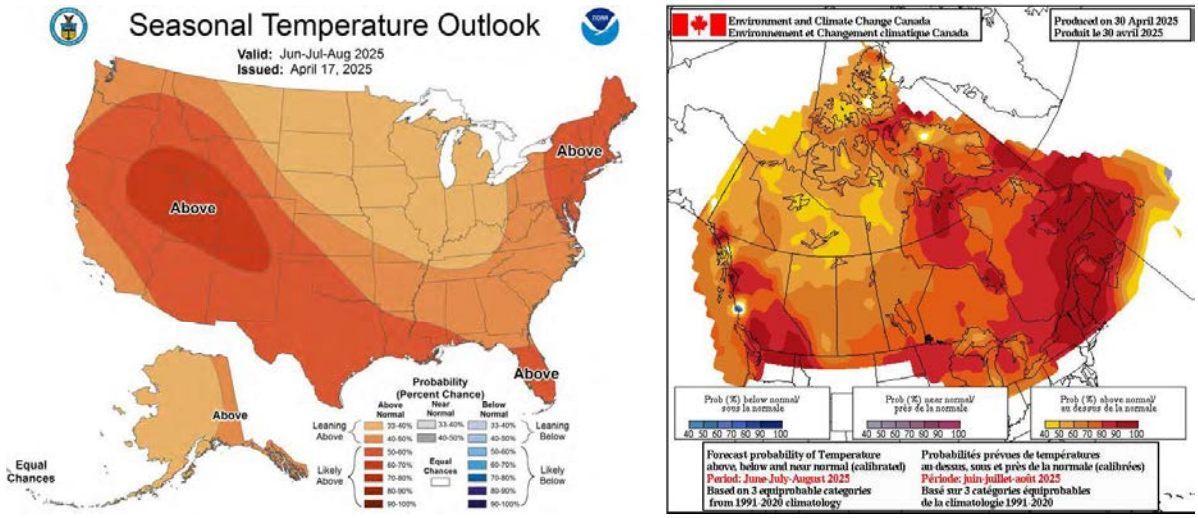


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 1.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 2.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

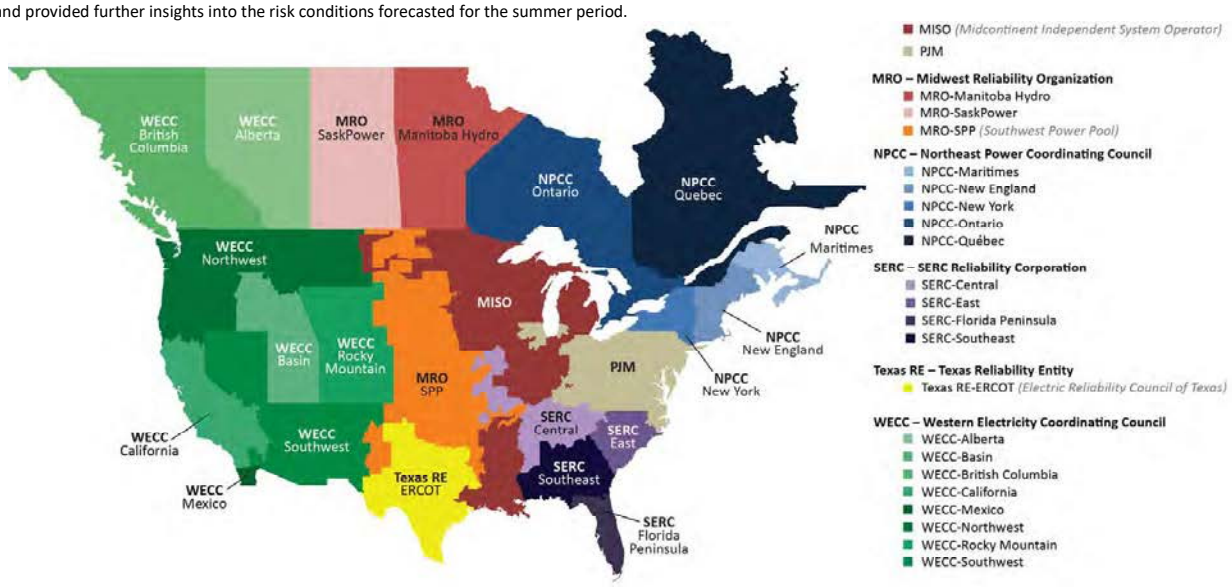
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central SERC-East SERC-Florida Peninsula SERC-Southeast	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



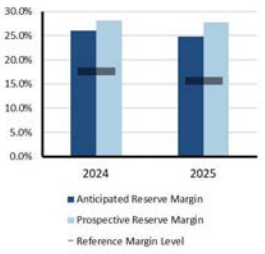
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

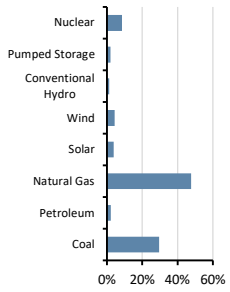
On-Peak Reserve Margin



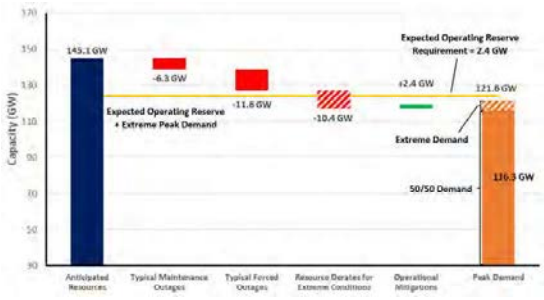
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions

MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

Highlights

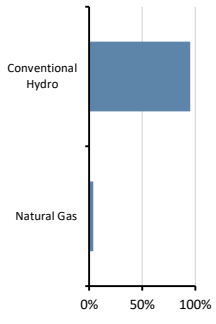
- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

Risk Scenario Summary

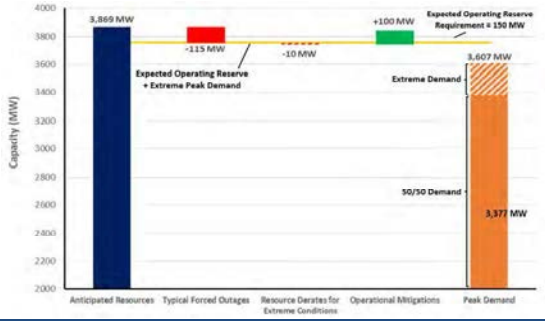
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

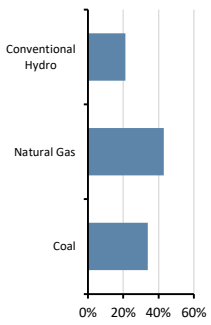
- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

Risk Scenario Summary

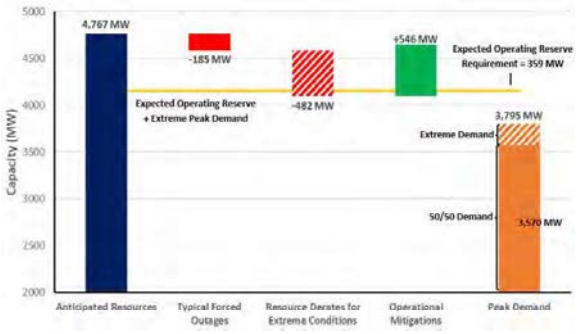
Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice

MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Highlights

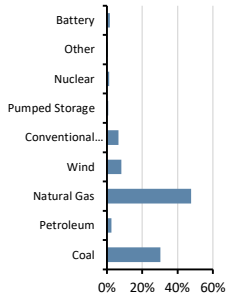
- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

Risk Scenario Summary

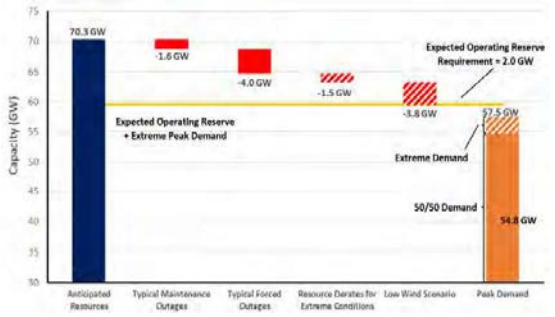
Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

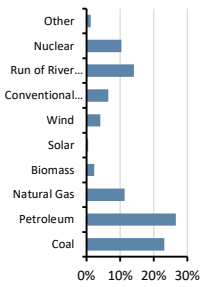
- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

Risk Scenario Summary

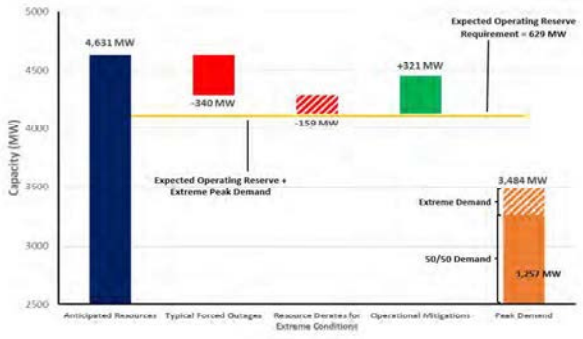
Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)

NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

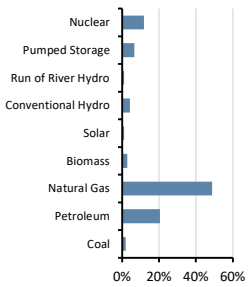
- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

On-Peak Reserve Margin

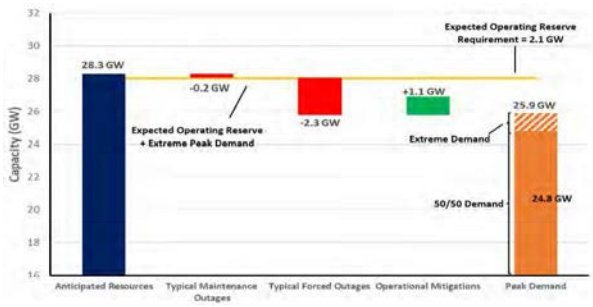
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

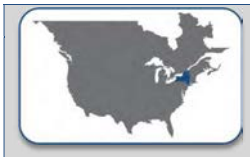
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

Highlights

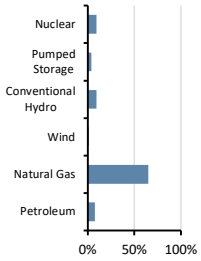
- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

Risk Scenario Summary

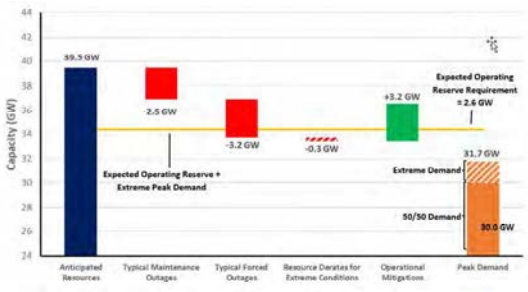
Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual

NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

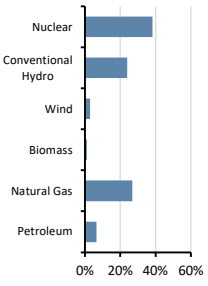
- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

Risk Scenario Summary

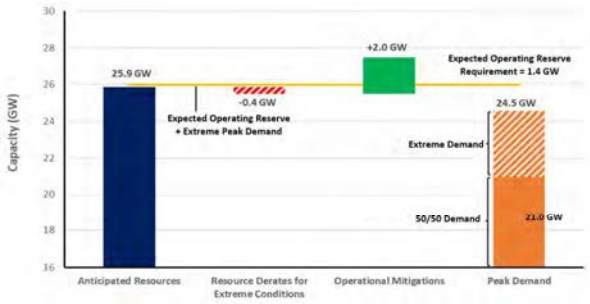
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.

NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

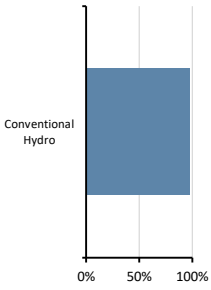
- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

Risk Scenario Summary

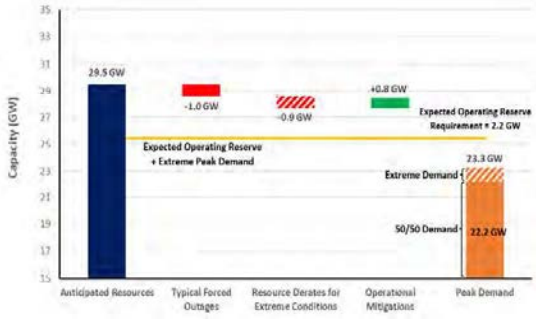
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.

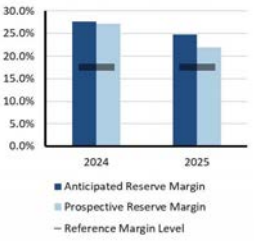
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

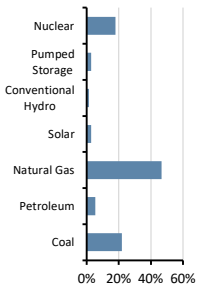
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

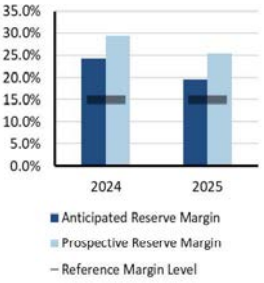
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

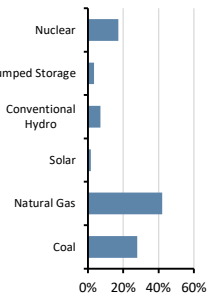
On-Peak Reserve Margin



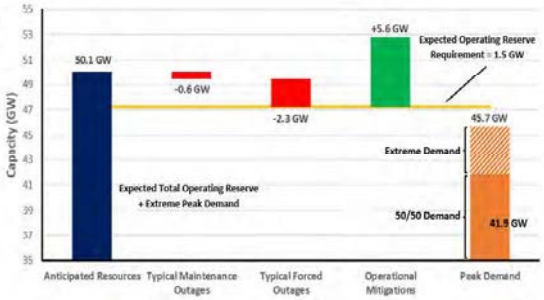
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures

SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

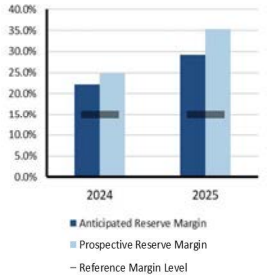
Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

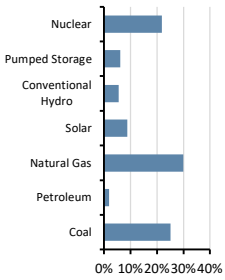
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures

SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

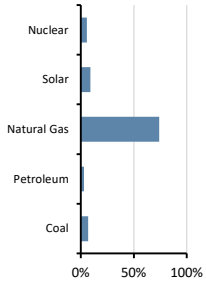
- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

On-Peak Reserve Margin

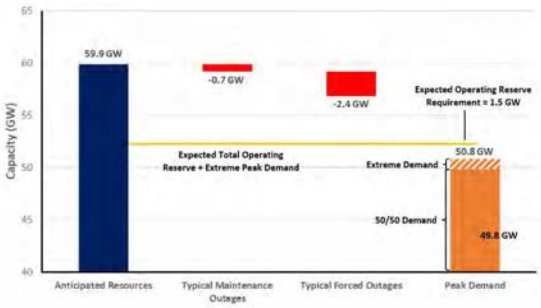
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

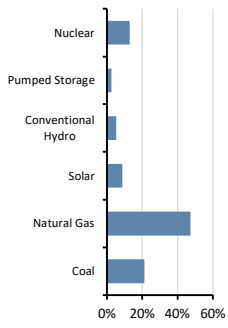
- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

On-Peak Reserve Margin

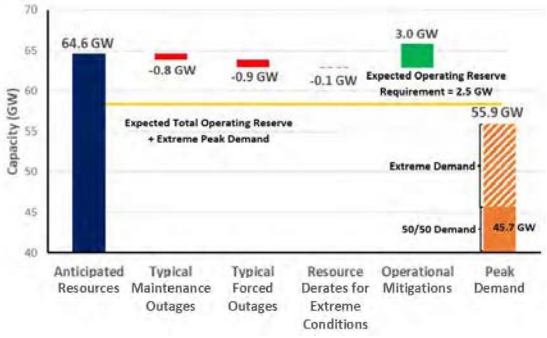
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

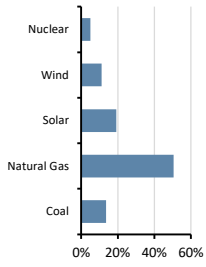
- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

Risk Scenario Summary

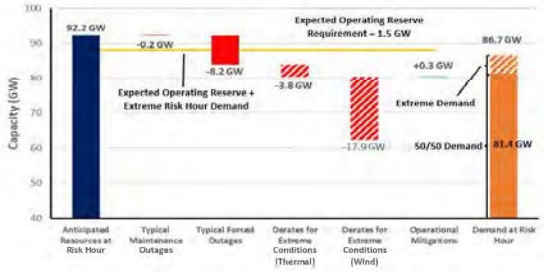
Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports

WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

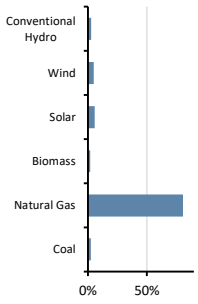
- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

Risk Scenario Summary

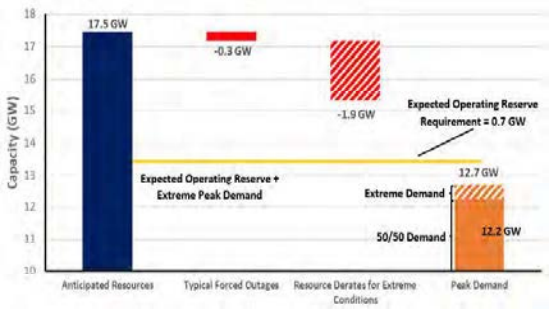
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

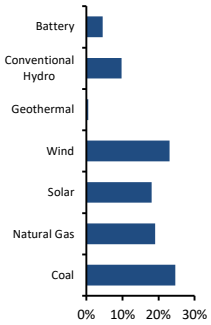
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios with imports.

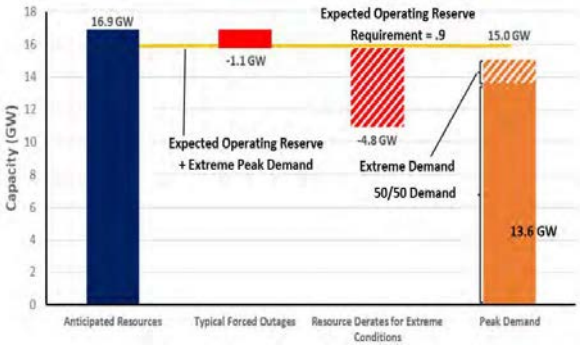
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

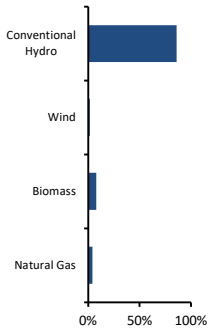
- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

Risk Scenario Summary

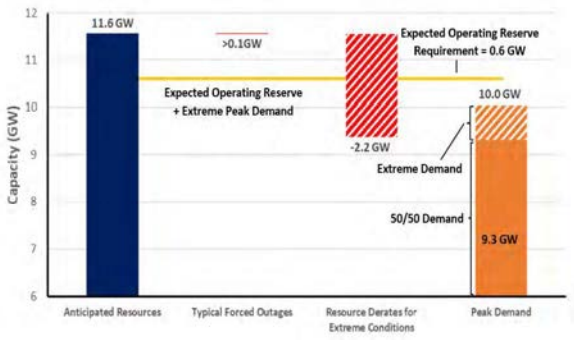
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-California

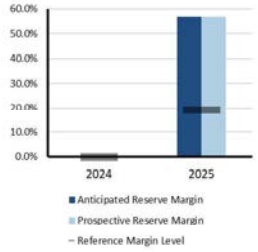
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

On-Peak Reserve Margin

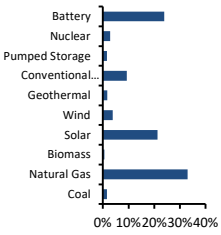
(Note: year comparison not available)



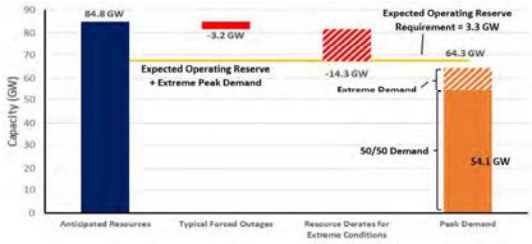
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages

WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

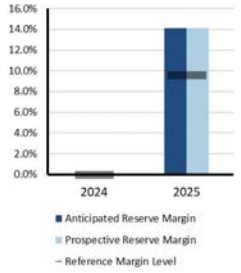
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

Risk Scenario Summary

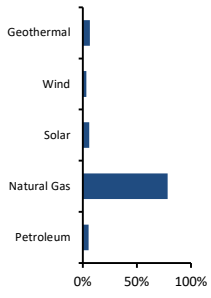
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

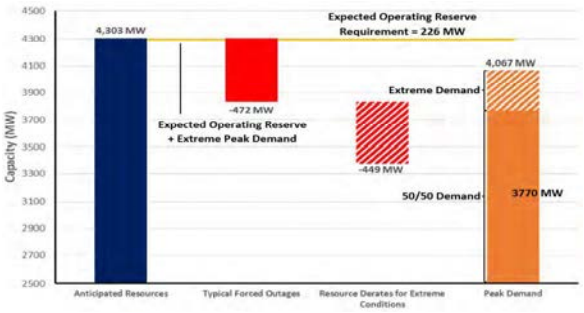
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

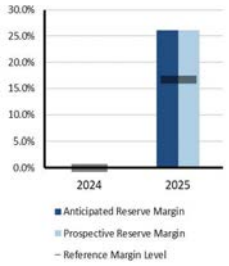
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

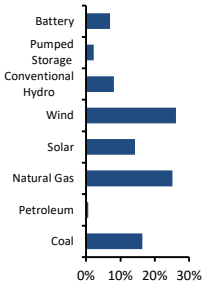
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

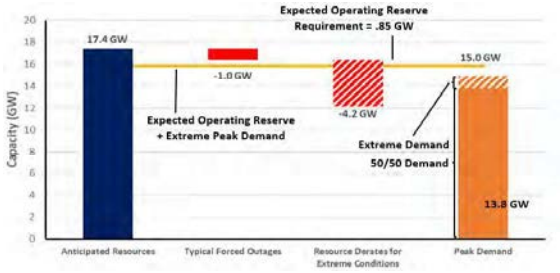


(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA*.

Highlights

- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

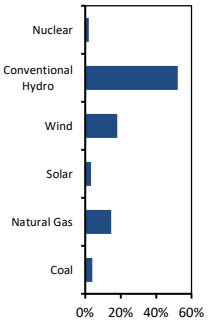
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

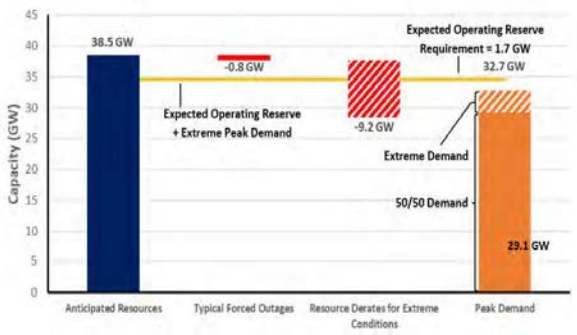
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

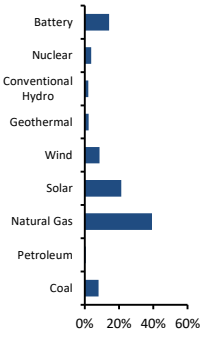
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

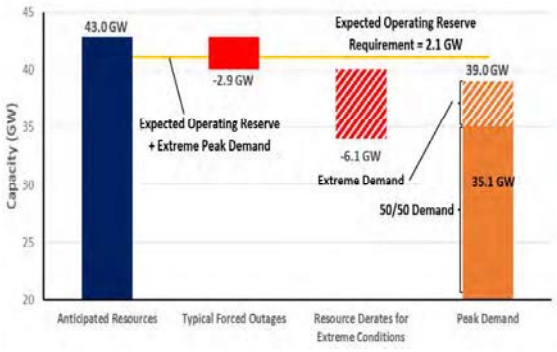
On-Peak Reserve Margin

(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[12] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[13] The summer season represents June–September and the winter season represents December–February.

[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the summer 2025 as shown in **Figure 4**.

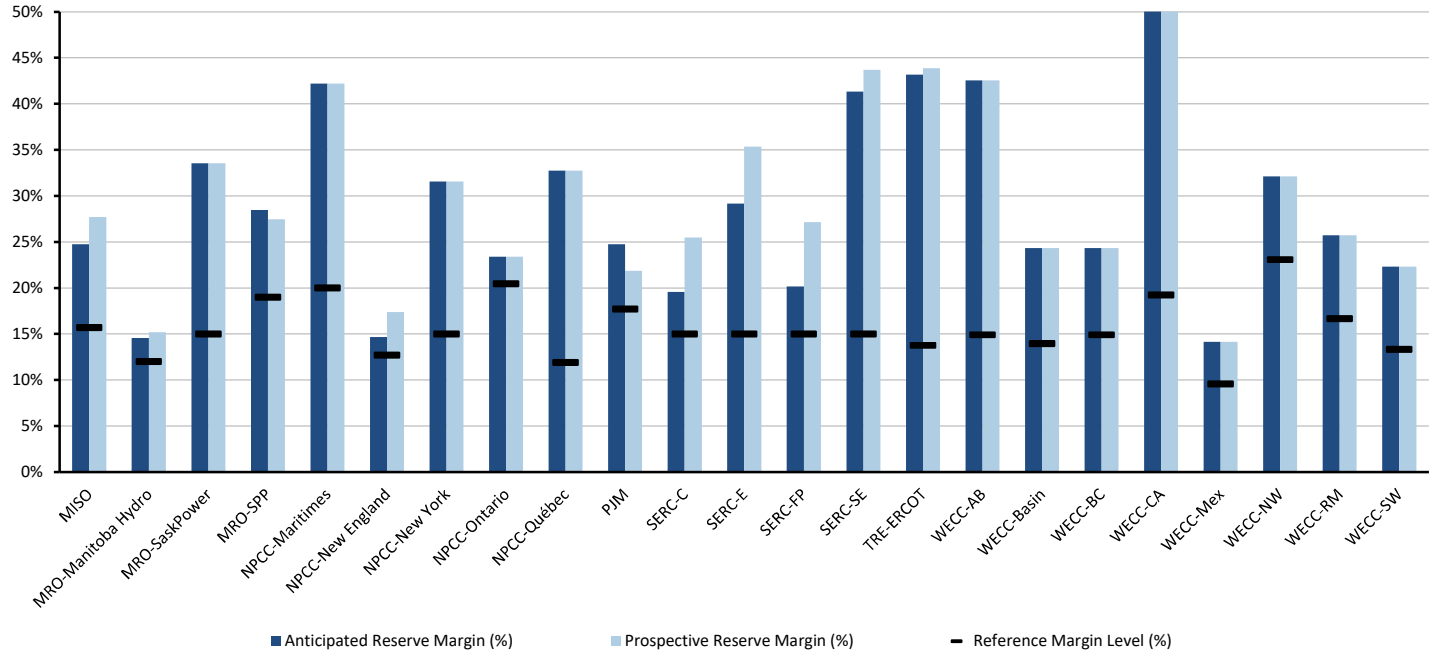


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

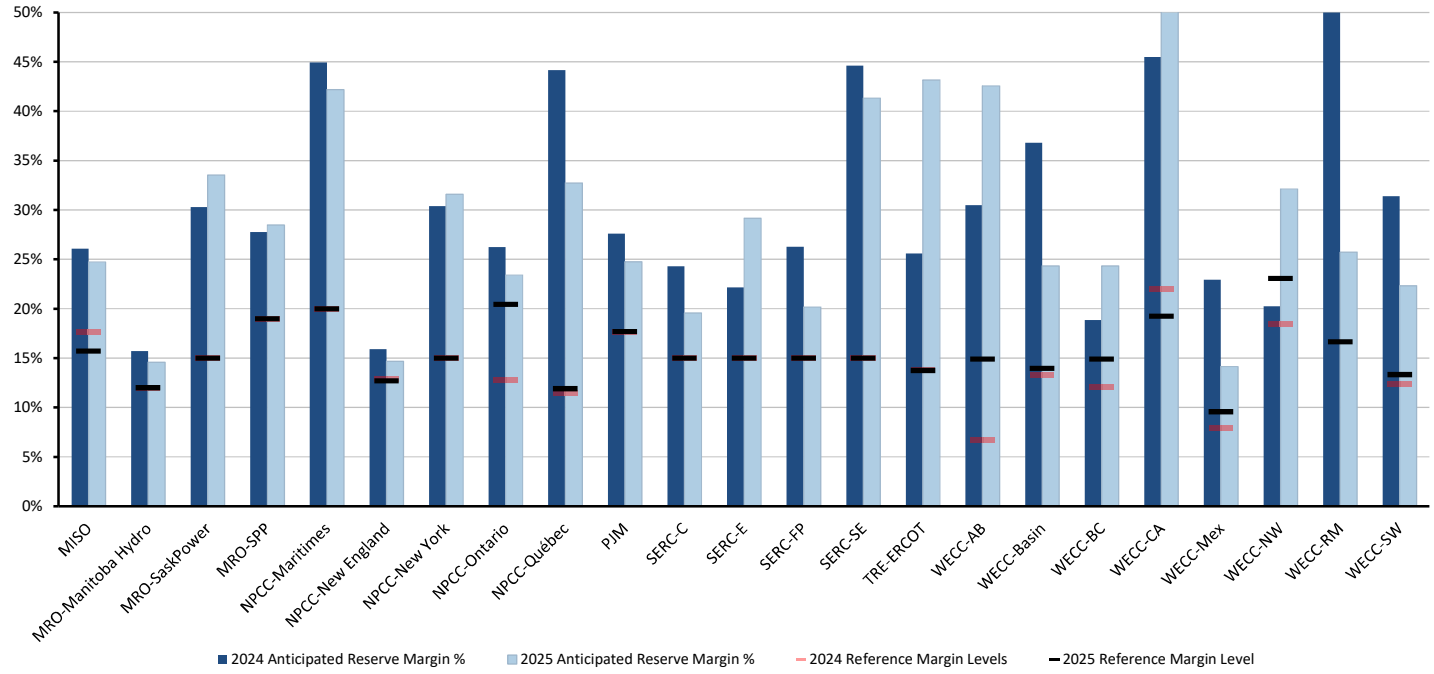


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

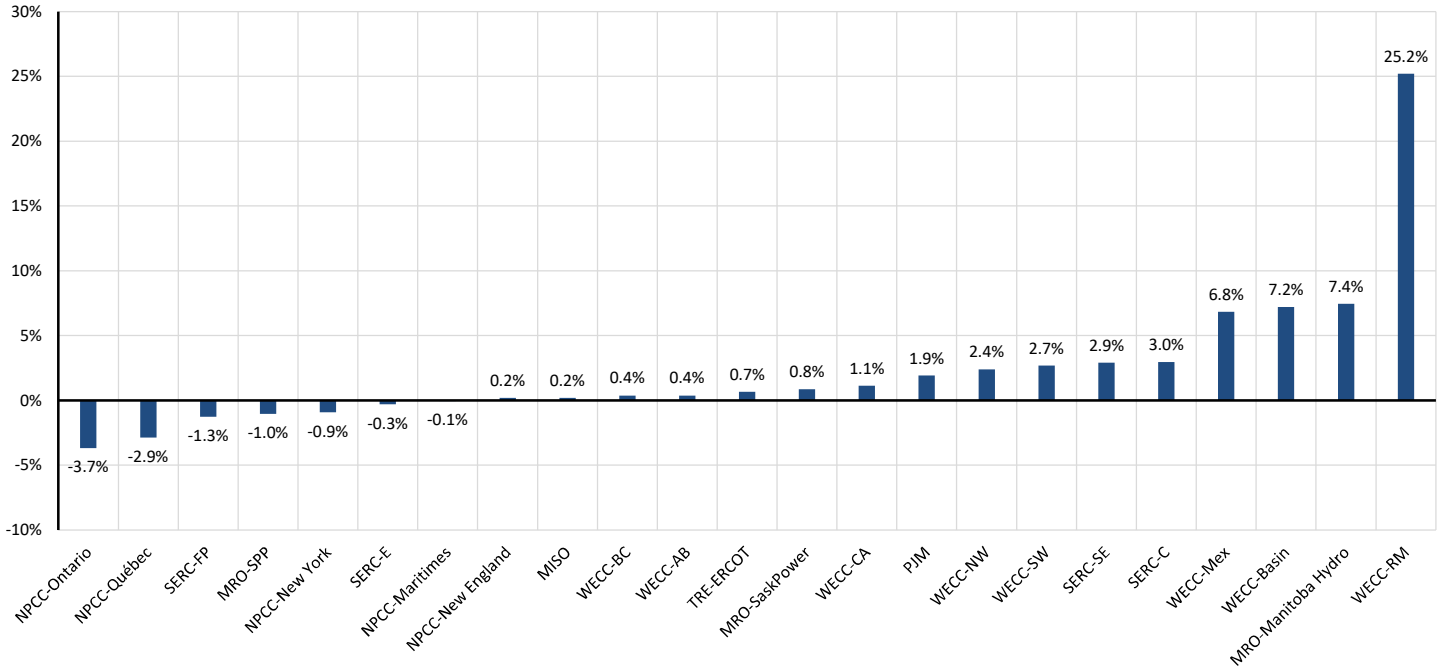


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	175,081	34,774	20%	142,014	86,170	61%	101,959	65,290	64%	36,311	32,298	89%

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta's demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.
[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2024 SRA*.
[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.
*Values include both maintenance and forced outages.
**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Attachment B

MISO 2025 PRA Report

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…

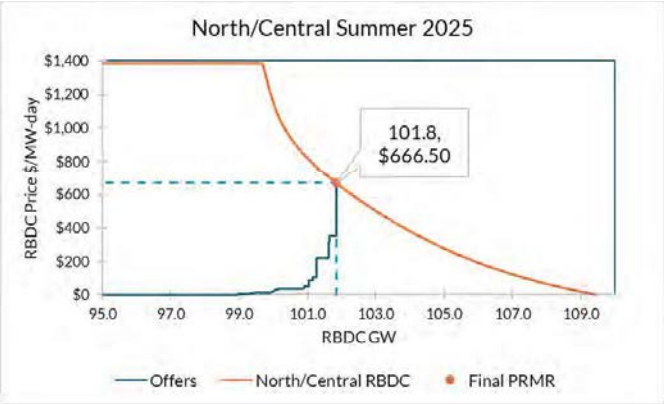
- Delivers competitive prices aligned with seasonal risks and tightening surplus
  - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
  - Clears capacity above target Planning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

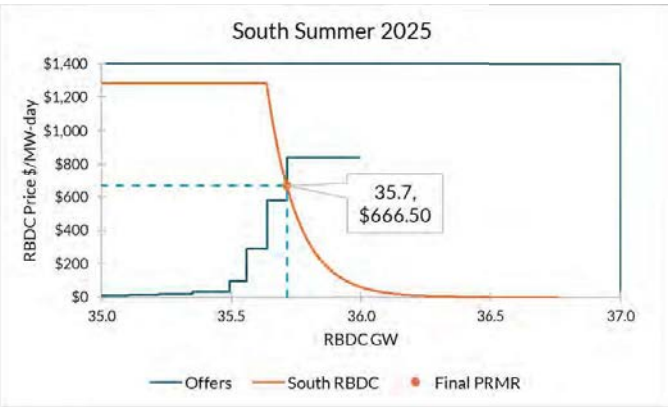
Why it Matters

- 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

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

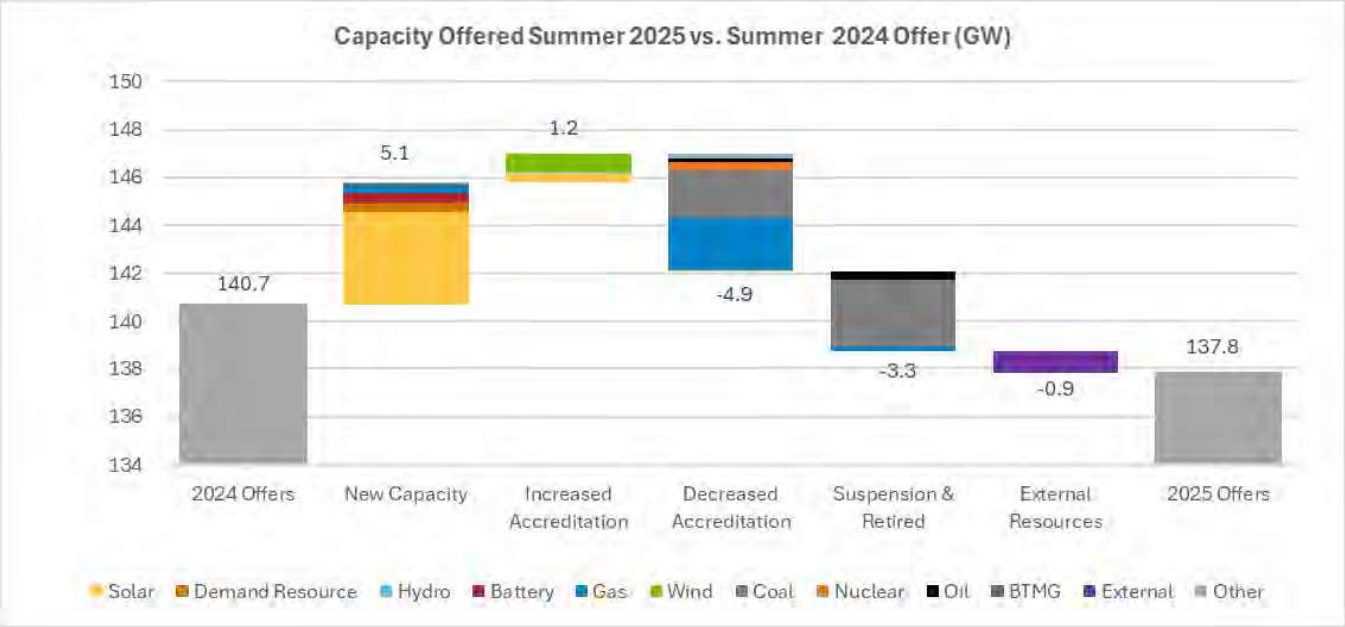
- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

	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

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

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

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

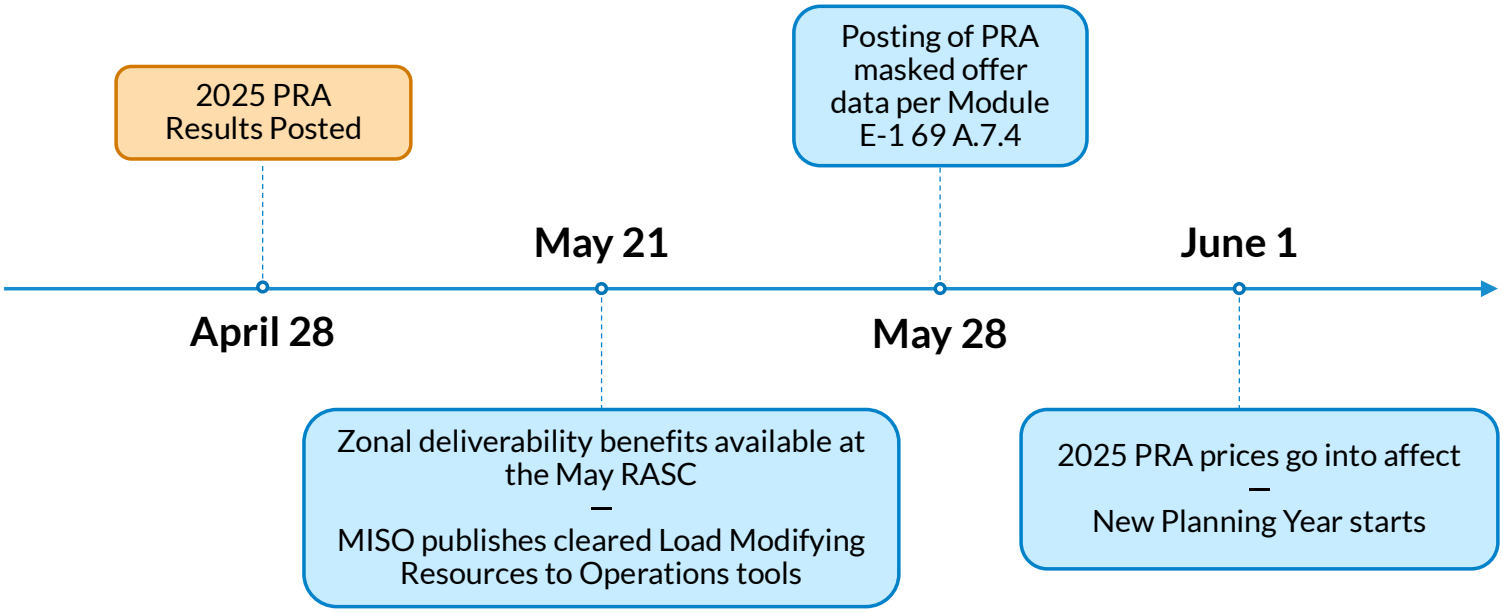
- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025)*
- ✓ Approved over $30 billion in new transmission 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

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

Next Steps


2025 PRA Results Posted
Posting of PRA masked offer data per Module E-1 69 A.7.4
April 28
May 21
May 28
June 1
Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools
2025 PRA prices go into affect
—
New Planning Year starts

Appendix

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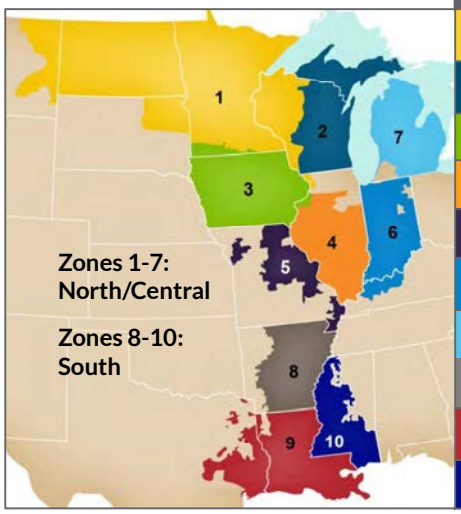
Acronyms

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

2025 PRA Results

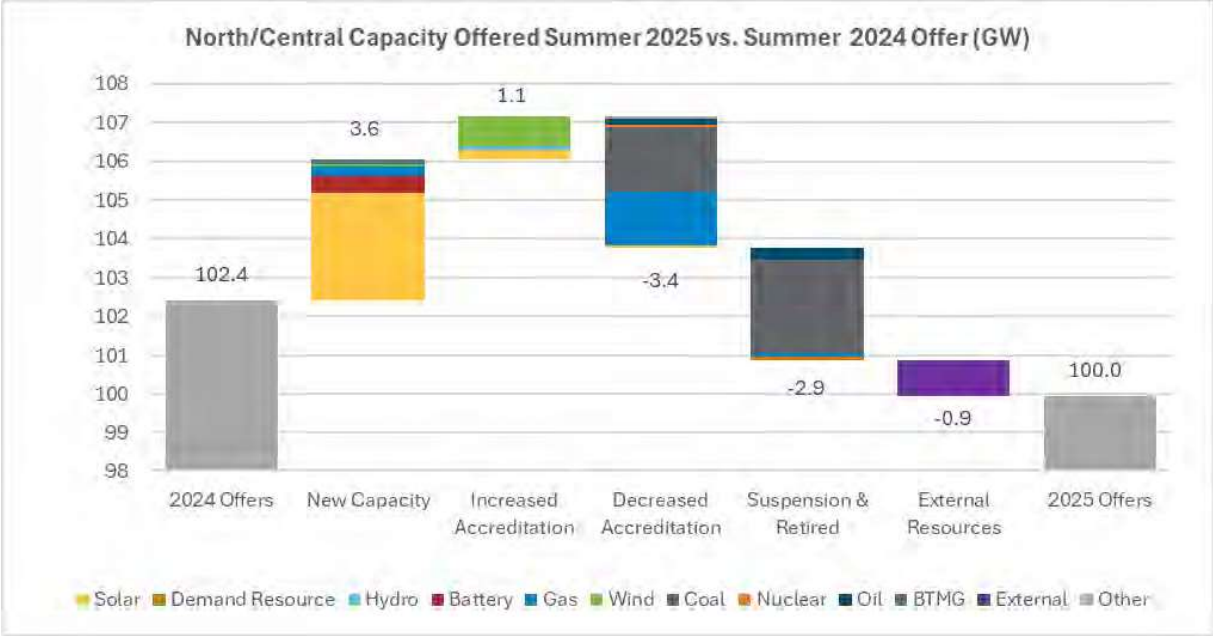
MISO Resource Adequacy Zones



	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	$666.50	$91.60	$33.20	$69.88
2				
3				
4				
5				
6				
7				
8		$74.09		
9				
10				

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

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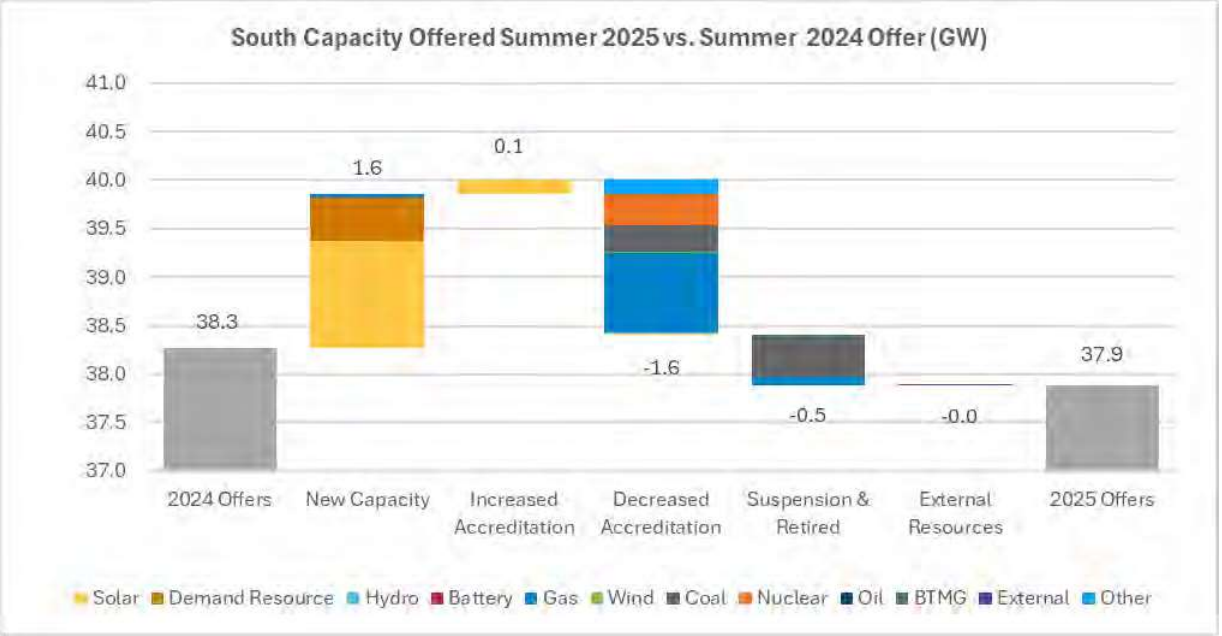
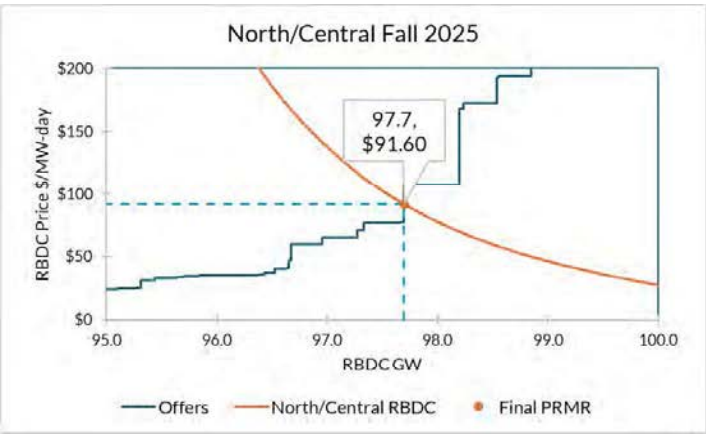
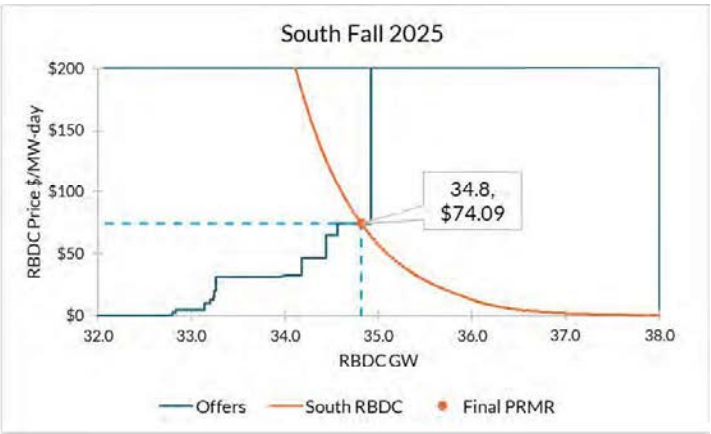
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



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

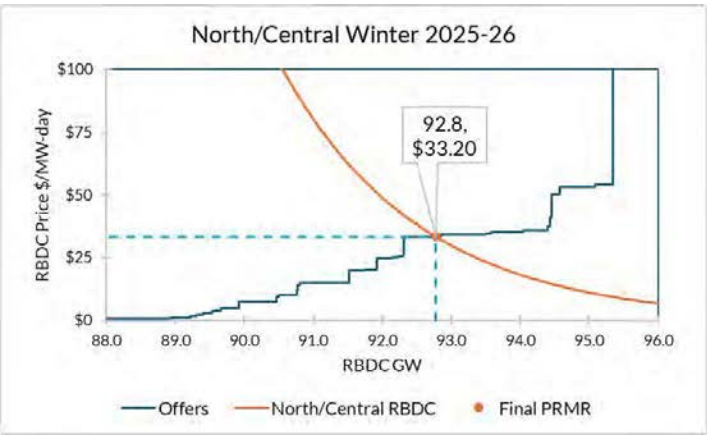
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

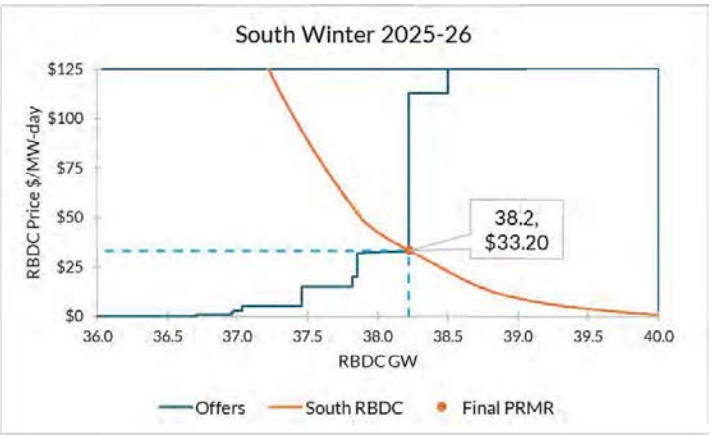




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
  - ACP for North subregion is $91.60, and $74.09 South subregion
  - A marginal 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%

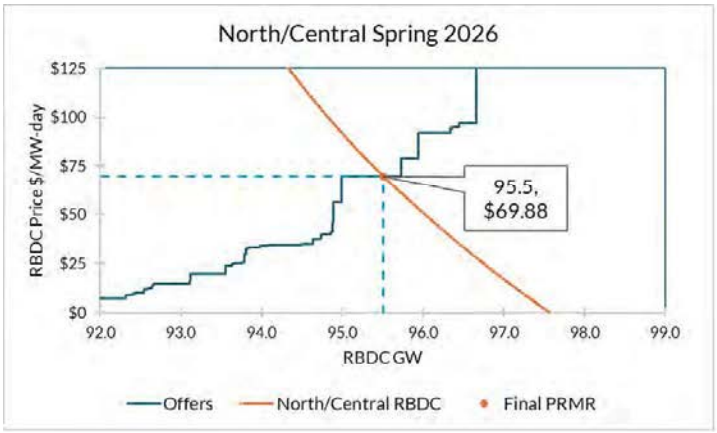
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices





- 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

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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

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

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

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

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

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

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

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

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
Fall 2025	$91.60							$74.09			$83.24-$91.60

- 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

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

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

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

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

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

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

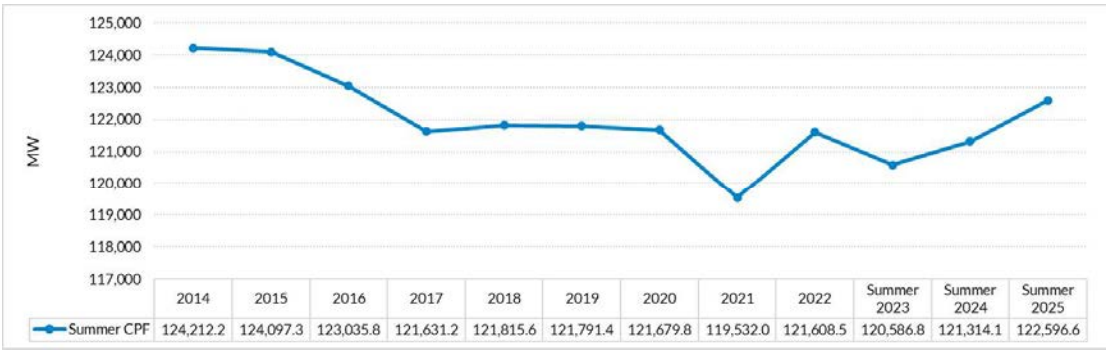
2024 OMS-MISO Survey Projection vs. 2025 PRA Actual PRMR Surplus (MW)

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

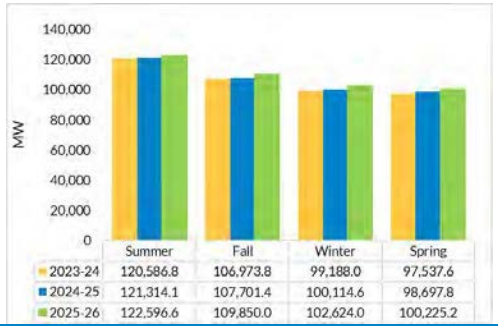
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

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

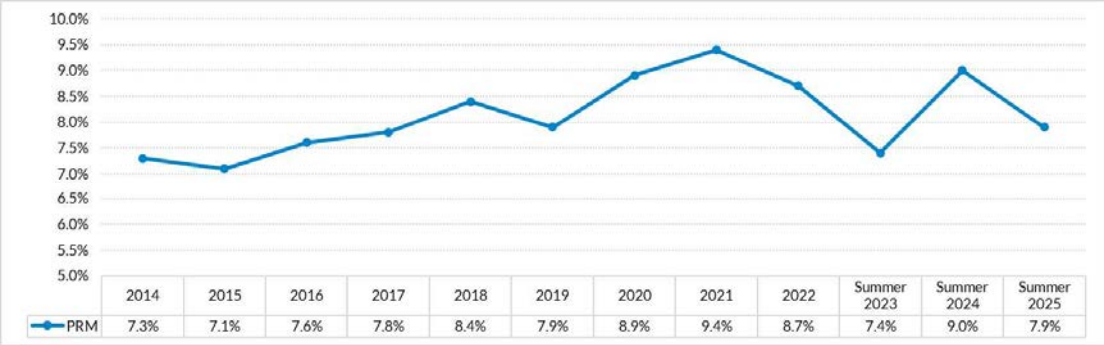


	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

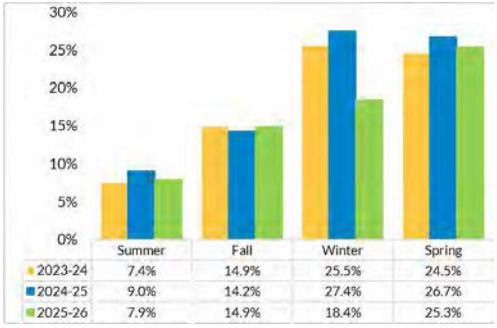
PRMR: Planning Reserve Margin Requirement

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

Planning Reserve Margin (%)

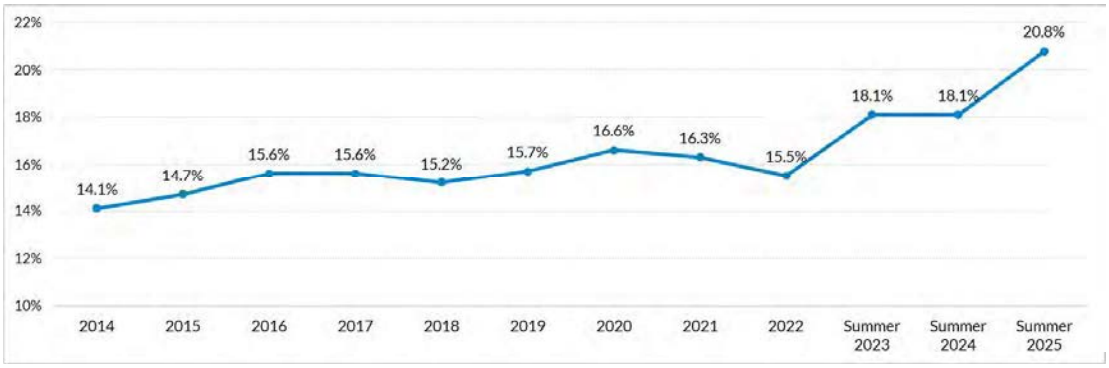


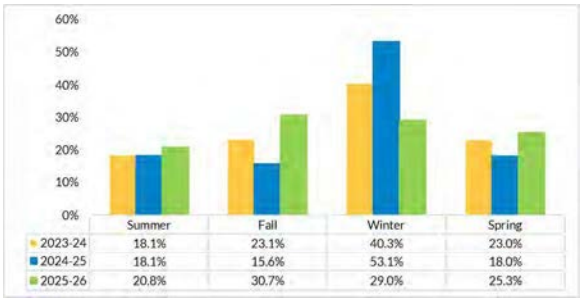
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	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 (%)





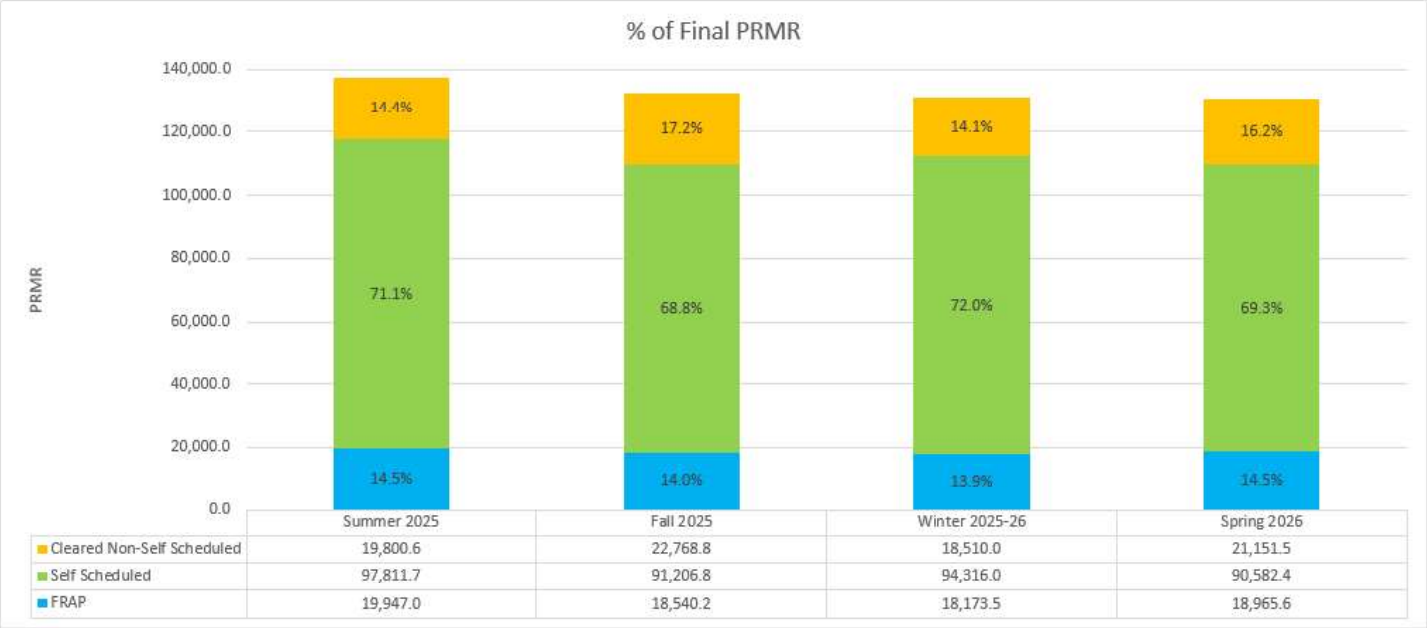
	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%
2025-26	20.8%	30.7%	29.0%	25.3%

- 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

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

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

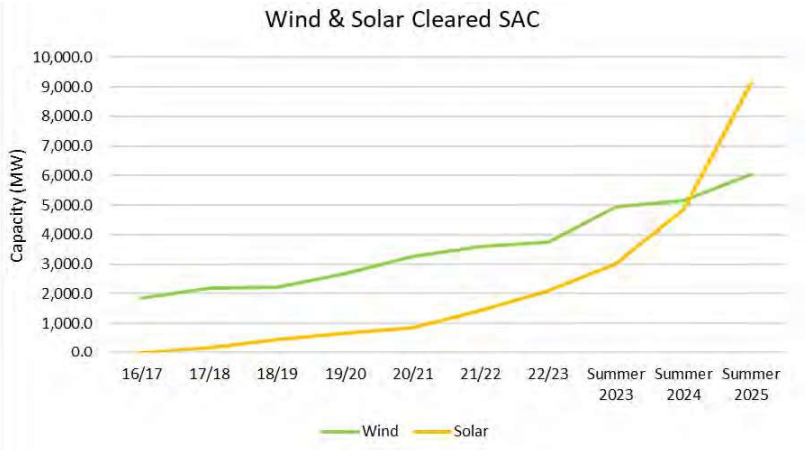


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

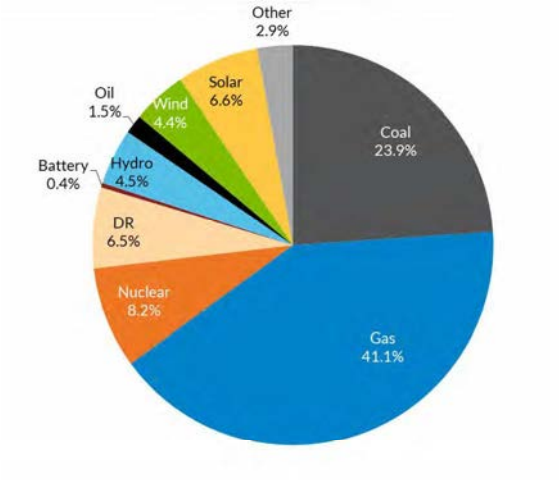
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 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

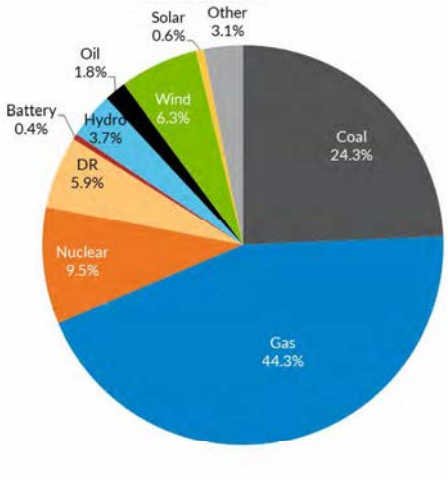
Summer 2025



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

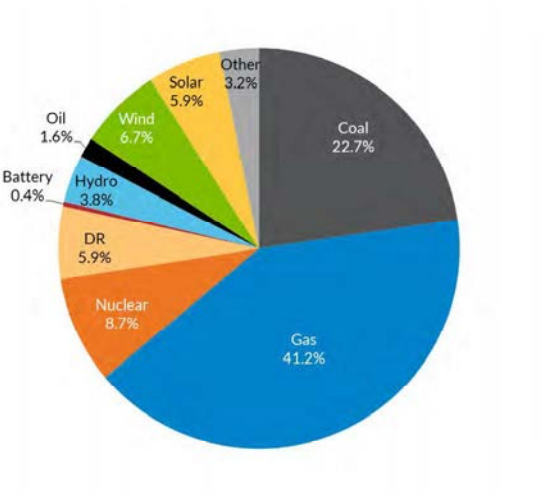


PRMR: Planning Reserve Margin Requirement

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

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

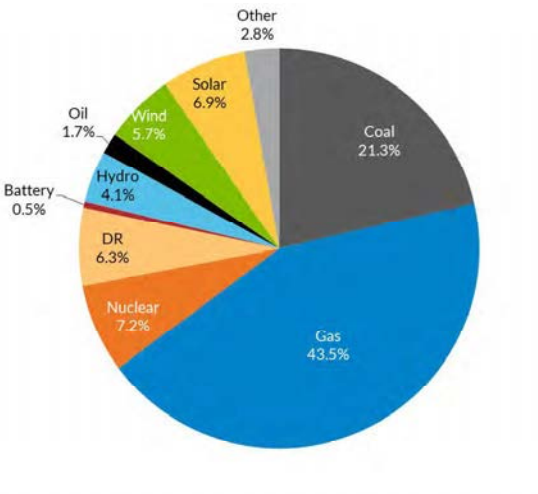
Fall 2025



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

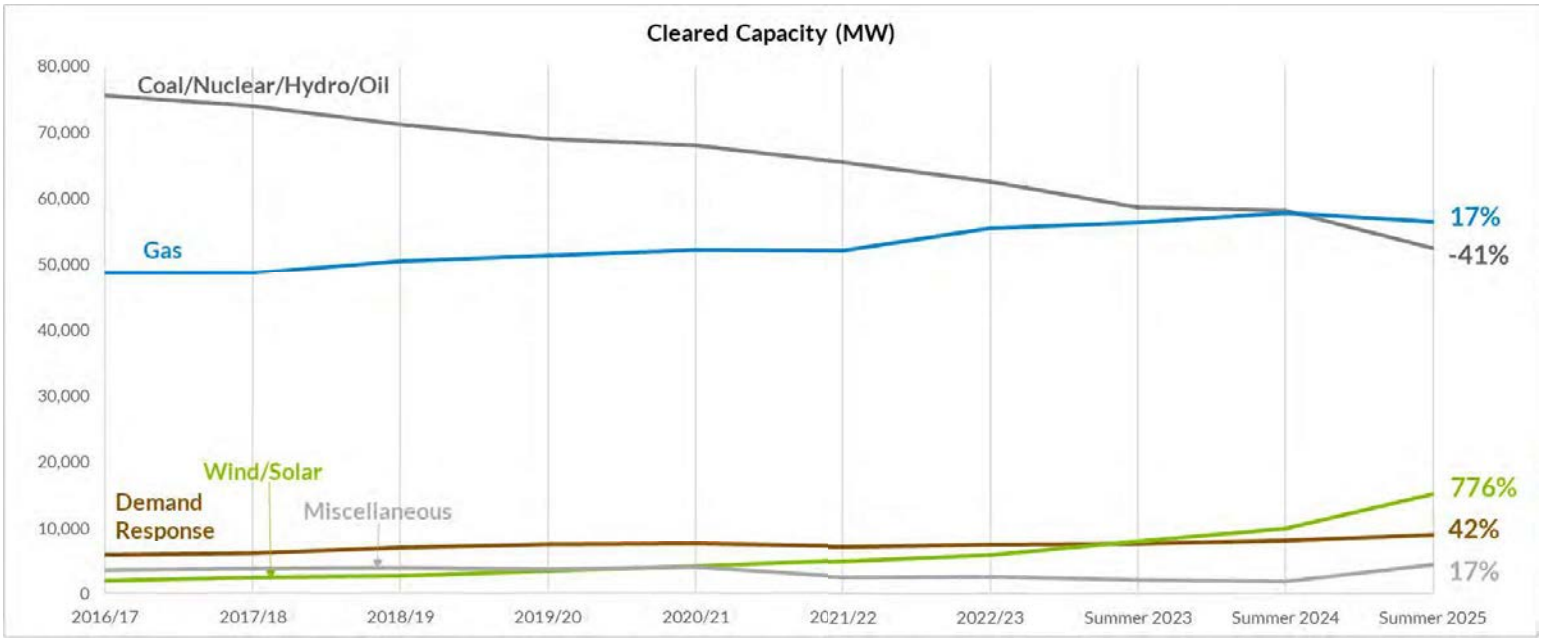
Spring 2026



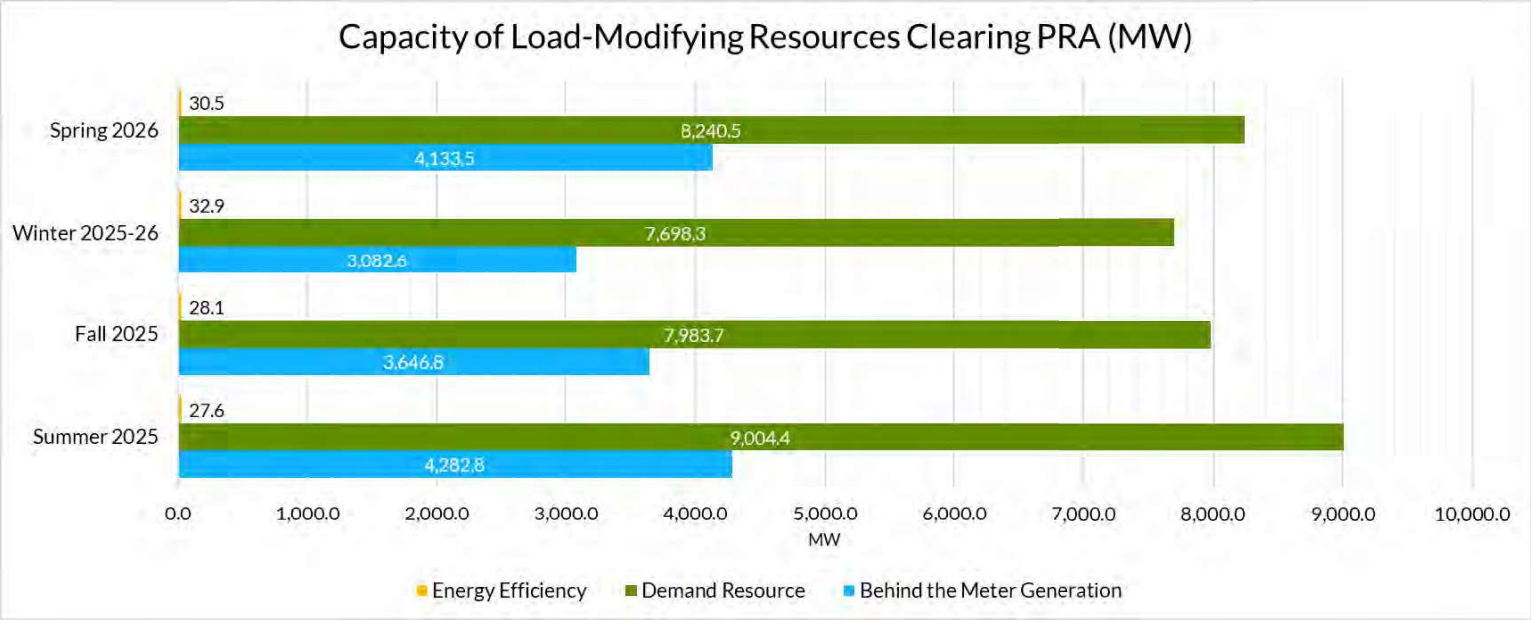
PRMR: Planning Reserve Margin Requirement

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

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/

Attachment C

Collection of MISO Attachment Y materials

Consumers Energy
Count on Us®

A CMS Energy Company

Timothy J. Sparks, P.E.
Vice President Electric Grid Integration

VIA Electronic Mail

December 14,2021

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

Re: Suspension of Campbell Units 1, 2 & 3

Dear Mr. Witmeier:

Consumers Energy Company ("Company") hereby provides notice to the Midcontinent Independent System Operator, Inc. ("MISO") that it intends to suspend Campbell Units 1, 2 and 3 effective June 1, 2025. Attached is the notice of such intent in accordance with Section 38.2.7 and Attachment Y of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

Campbell Unit 3 is jointly owned by the Company (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that, pursuant to the relevant Operating Agreements, it is authorized to submit this Attachment Y notice on behalf of all Campbell Unit 3 owners.

In the event you have any questions regarding this matter, please contact Kathy Wetzel at (517) 788-2039.

Regards,

Timothy J. Sparks
Vice President Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Cc: Kathy Wetzel
Thomas Clark

Electric Supply
Contract/Commitment Cover Sheet

(Note: Contracts, purchase orders, or other commitment instruments will not be signed unless this sheet is completed in full)

Subject/Commitment: MISO Attachment Y Notification of Generating Resources /SCU/ Pseudo-tied Out Generator Change of Status / Including Notification of Rescission Form

Reason: Notice to Suspend Karn Units 3 & 4 effective June 1, 2023.

Check One			
Yes	No*	N/A	
☐	☐	☒	1) Gateway Assessment Tool completed and attached
☒	☐	☐	2) Legal Review / Approval to Form
☐	☐	☒	3) Credit Risk Management Approval
☐	☐	☒	4) Competitive Bid
☐	☐	☒	5) Sole Source Approval completed and attached

*If No is checked or special circumstances apply, please explain:

Legal review by Emerson Hilton.

*Contract Owner: Kathy Wetzel

Department Sign Off
(Signature & Date Required)

ML Metz
Merchant Ops & PSCR

KG Troyer
EGI Contracts & Settlements
Renewables

BD Gallaway
Fuel Supply

TP Clark
Electric Supply

12/14/2021

TJ Sparks
Electric Grid Integration

Form Revised: 04/16/21

*Contract Owner Responsible for Scanning & Placing on SharePoint Site

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic copy of the completed form will be accepted by the Transmission Provider, however, a form will not be considered complete until the original form containing an original signature, including all attachments, is received by the Transmission Provider at the following address: MISO, Attention: Director of Transmission Planning; 720 City Center Drive, Carmel, IN 46032.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re: Campbell Unit 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] CAMPBELL UNITS 1+2: UMBRELLA GIA BETWEEN CONSUMERS, METC + MISO FERC DOCKET ER21-999. CAMPBELL UNIT 3: FERC DOCKET ER06-1441 FOR MISO SERVICE AGREEMENT NO. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 1st [day] of June [month] of 2025 [year]

[ ] Rescind the current notice to SuspendThe facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: TIMOTHY J SPARKS

Title: VP ELECTRIC GRID INTEGRATION

Date:

Contact Information

Email: TIMOTHY.SPARKS@CMSENERGY.COM

Phone: 517 788 1053

Andrew Witmeier
Director, Resource Utilization
317-249-5585
awitmeier@misoenergy.org

VIA OVERNIGHT DELIVERY

March 11, 2022

Timothy J. Sparks
Vice President, Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Subject: **Approval of Campbell Units 1,2 &3 Attachment Y Suspension Notice**

Dear Mr. Sparks,

On December 14, 2021, Consumers Energy Company submitted an Attachment Y Notice to MISO for the suspension of Campbell Units 1,2 & 3, effective June 1, 2025. After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the suspension of Campbell Units 1,2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,2 & 3 may suspend without the need for the generators to be designated as a System Support Resource ("SSR") units as defined in the Tariff.

As there were no reliability criteria violations, MISO will continue to preserve the confidentiality of the Attachment Y Notice.

Please do not hesitate to contact me if you have any questions regarding this matter.

Respectfully,

Andrew Witmeier
Director, Resource Utilization

VIA EMAIL

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

May 28, 2025

Re: Modified Suspension Date for Campbell Units 1, 2, & 3

Mr. Witmeier:

On December 14, 2021, Consumers Energy Company ("Consumers Energy") submitted an Attachment Y Notice to the Midcontinent Independent System Operating, Inc. ("MISO") for the suspension of Units 1, 2, and 3 at the J.H. Campbell Generation Complex ("Campbell Plant"), effective June 1, 2025. After reviewing for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), MISO determined the suspension of Campbell Plant Units 1, 2, and 3, would not result in violations of applicable reliability criteria, as outlined in the Tariff. On March 11, 2022, MISO approved the suspension of Campbell Plant Units 1, 2, and 3 without the need for the generators to be designated as System Support Resource units as defined in the Tariff.

On May 23, 2025, the U.S. Department of Energy ("DOE") issued Order No. 202-25-3 (the "Order"), requiring the Campbell Plant to be available to MISO through August 20, 2025.

In order to comply with the Order, Consumers Energy hereby provides notice to MISO, consistent with Section 38.2.7(d)(ii)(1) of the Tariff, of its intent to modify the current Attachment Y Notice such that the Campbell Plant will now suspend on August 21, 2025.

As noted in Consumers Energy's original Attachment Y Notice, Campbell Unit 3 is jointly owned by Consumers Energy (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that it has notified all Campbell Unit 3 owners of this submittal.

In the event you have any questions regarding this matter, please contact Derek Anspaugh at (517) 788-1869.

Regards,

Sri Maddipati
VP Electric Supply
1945 W. Parnell Rd
Jackson, MI 49901

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic form must be submitted to the Transmission Provider via its online application tool in the manner specified by the Transmission Planning Business Practices Manual (BPM-020), and a form will be considered complete on the date of such online application.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re Campbell 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement]
Campbell Units 1 & 2: Umbrella GIA Between Consumers, METC, and MISO, FERC Docket No. ER24-1359
Campbell Unit 3: FERC Docket No. ER06-1441 for MISO Service Agreement No. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 21 [day] of August [month] of 2025 [year]

[ ] Rescind the current notice to Suspend

The facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: Srikanth Maddipati

Title: VP Electric Supply

Date: May 28, 2025

Contact Information

Email: sri.maddipati@cmsenergy.com

Phone: 517-788-0635

From:	Marc Keyser
To:	Rachael H. Moore; Huaitao Zhang; DEREK S. ANSPAUGH; Adam C. French; NICHOLAS B. TENNEY; Emerson J. Hilton
Cc:	Sumit Pal Brar
Subject:	RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required
Date:	Friday, May 30, 2025 4:05:01 PM

##CAUTION##: This email originated from outside of CMS/CE. Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Rachael: I'm responding back on behalf of the team, after they briefly reviewed with legal here:

we received the Attachment Y, and the new cessation is 8/21/2025. Additionally, you have until 8/21/2027 to submit a new replacement request before the suspension period ends. In other words, the Attachment Y remains as is, still approved, except with a new/different start date.

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Friday, May 30, 2025 12:15 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Warning! This email originated from outside the organization and caution should be used when clicking on links/attachments. If you suspect this email is malicious, use the 'Phish Alert' button.

Thank you, Huaitao. Can you confirm that this modification of the suspension start date provided consistent with Section 38.2.7(d)(ii)(1) of the Tariff does not impact the overall approval of the Attachment Y the Company previously received on March 11, 2022, and that the Company is still approved to enter suspension (now effective 8/21/25)?

Thank you!

Rachael Moore | Senior Attorney
[redacted]

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Wednesday, May 28, 2025 1:47 PM

To: Rachael H. Moore <Rachael.Moore@cmsenergy.com>; DEREK S. ANSPAUGH <DEREK.ANSPAUGH@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

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Rachael,

Thanks for the quick response, and we are all good.

Thanks,
Huaitao

From: Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Sent: Wednesday, May 28, 2025 12:40 PM
To: Huaitao Zhang <HZhang@misoenergy.org>; Derek Anspaugh <Derek.Anspaugh@cmsenergy.com>; Adam French <adam.french@cmsenergy.com>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Emerson J. Hilton <Emerson.Hilton@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: [EXT]RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

> **Warning!** This email originated from outside the organization and caution should be used when clicking on links/attachments. If you suspect this email is malicious, use the 'Phish Alert' button.

Huaitao –

Attached is the modified Attachment Y with the amended suspension start date of 8/21/2025. Please let me know if we should send this notice of Modified Attachment Y to anyone else at MISO or if you would like us to mail a physical copy as well.

Thank you,
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Rachael H. Moore
Sent: Tuesday, May 27, 2025 11:52 AM
To: Adam C. French <adam.french@cmsenergy.com>; Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <nicholas.tenney@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Good afternoon,

Yes, I will be working with members of the Company to ensure we have the Attachment Y notice updated by 5/28. Please let me know if there is a specific contact at MISO we should plan to send this to.

Thank you!
Rachael

Rachael Moore | Senior Attorney
[redacted]

From: Adam C. French <ADAM.FRENCH@cmsenergy.com>
Sent: Tuesday, May 27, 2025 11:49 AM
To: Huaitao Zhang <HZhang@misoenergy.org>; NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Rachael H. Moore <Rachael.Moore@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: RE: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

It is my understanding that is being handled by Rachael Moore
RACHAEL.MOORE@CMSENERGY.COM

From: Huaitao Zhang <HZhang@misoenergy.org>
Sent: Tuesday, May 27, 2025 11:41 AM
To: NICHOLAS B. TENNEY <NICHOLAS.TENNEY@cmsenergy.com>; Adam C. French <ADAM.FRENCH@cmsenergy.com>
Cc: Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>
Subject: FW: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

You don't often get email from hzhang@misoenergy.org. Learn why this is important [aka.ms]

##CAUTION##: This email originated from outside of CMS/CE. Remember your security awareness training: Stop, think, and use caution before clicking links/attachments.

Nick and Adam,

Marc pointed to me that you are the contact for this request.

Thanks,
Huaitao

From: Huaitao Zhang
Sent: Tuesday, May 27, 2025 11:05 AM
To: KATHY S. WETZEL <KATHY.WETZEL@cmsenergy.com>
Cc: timothy.sparks@cmsenergy.com; Sumit Pal Brar <SBrar@misoenergy.org>; Marc Keyser <MKeyser@misoenergy.org>; Jagdesh Shivani <JShivani@misoenergy.org>
Subject: Order from Secretary of Energy to keep Campbell Unit ON for the summer (until Aug 21, 2025) - Action required

Hi Kathy,

Pertain to the Order from Secretary of Energy regarding the suspension/cessation date of Campbell units 1,2&3, MISO requests Consumer Energy to submit the following application updates to MISO by 5/28/2025:

Attachment Y request with suspension start date as 8/21/2025

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

Thanks,
Huaitao Zhang
Resource Utilization Engineer

Integrity | Collaboration | Commitment | Creativity | Adaptability

Attachment D

Consumers' Responses from June 10, 2025

Question:

23. Absent continued operation of the Campbell Plant, what was Consumers Energy's Zone Resource Credit (ZRC) position for planning year 2025-2026.

Response:

The table below shows our capacity positions using the initial Planning Reserve Margin Requirement (PRMR) for each season of planning year 2025. These numbers do not include any contributions from the Campbell coal-fired generating units.

PY2025	**ZRC**
Summer	272.9
Fall	842.7
Winter	0.0
Spring	4.3

Date: June 10, 2025

Question:

24. How many ZRCs does Consumers anticipate will be accredited for the continued operation of the Campbell Plant?

Response:

At this time we do not anticipate the Campbell units contributing any Zonal Resource Credits to our capacity positions throughout planning year 2025.

Date: June 10, 2025

Attachment R

DOE Final EO Report (FINAL JULY 7)

U.S. DEPARTMENT of ENERGY

Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation’s power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored “call to action” for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

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List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, "Declaring a National Emergency (Jan. 20, 2025)," which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE's response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable**. The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring "resource adequacy"). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.
- **Grid Growth Must Match Pace of AI Innovation**. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.
- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030**. The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the "plant closures" scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.
- **Planned Supply Falls Short, Reliability is at Risk**. The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.[1] A deterministic approach[2] simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)[3] and Lawrence Berkeley National Laboratory (LBNL).[4] This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,[5] reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.
2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.
3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, https://www.epri.com/research/products/3002028905.
4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," https://escholarship.org/uc/item/32d6m0d1.
5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics[6] are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

  While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100\ MWh\ (of\ unserved\ energy)}{10{,}000{,}000\ MWh\ (of\ total\ energy\ delivered\ in\ a\ year)} x100 = 0.001\ percent$$

Although the use of NUSE is not standardized in the U.S. today,[7] several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.
7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.[8] To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.[9] This translates into one day of lost load in ten years to meet the 1-in-10 criteria.

- **Magnitude of Outages:** No more than an NUSE of 0.002%.[10] This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures"** case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,[11] which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures"** case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.
9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.
10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.
10. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.

- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.

- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.

- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

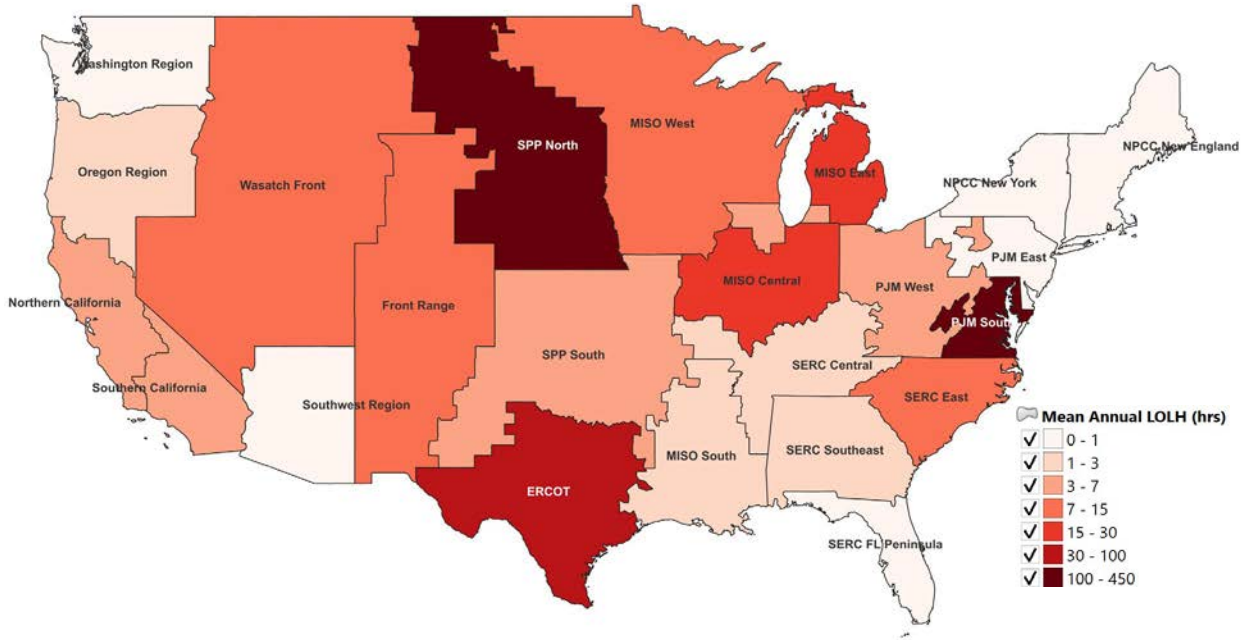


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

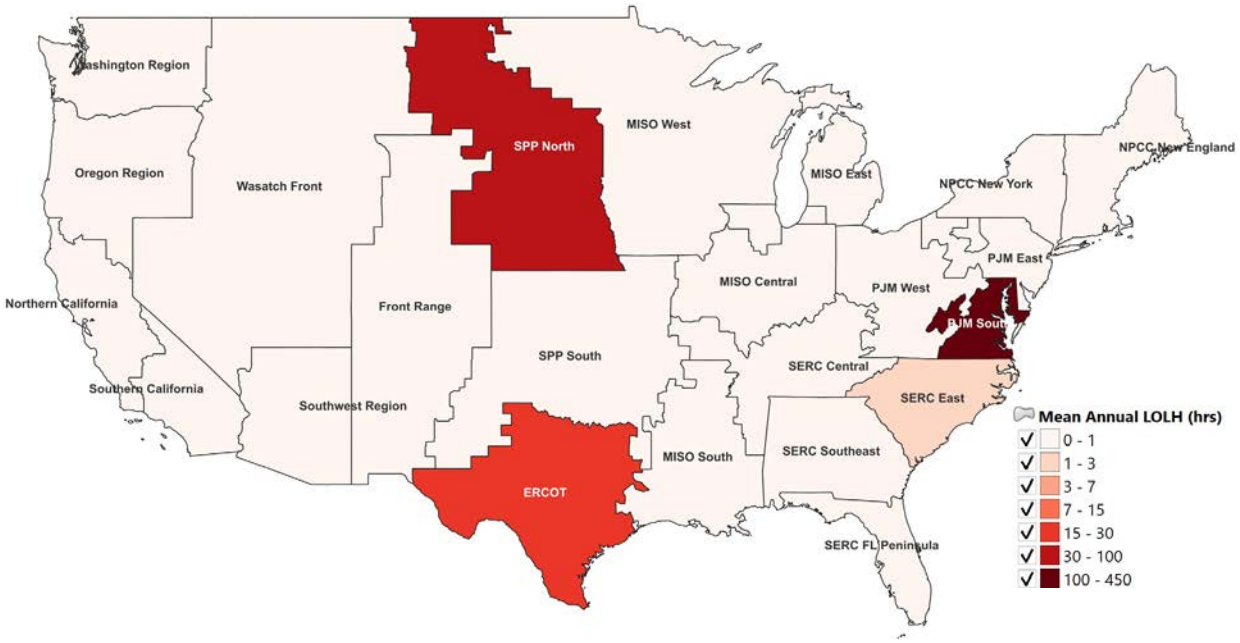


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,[12] and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

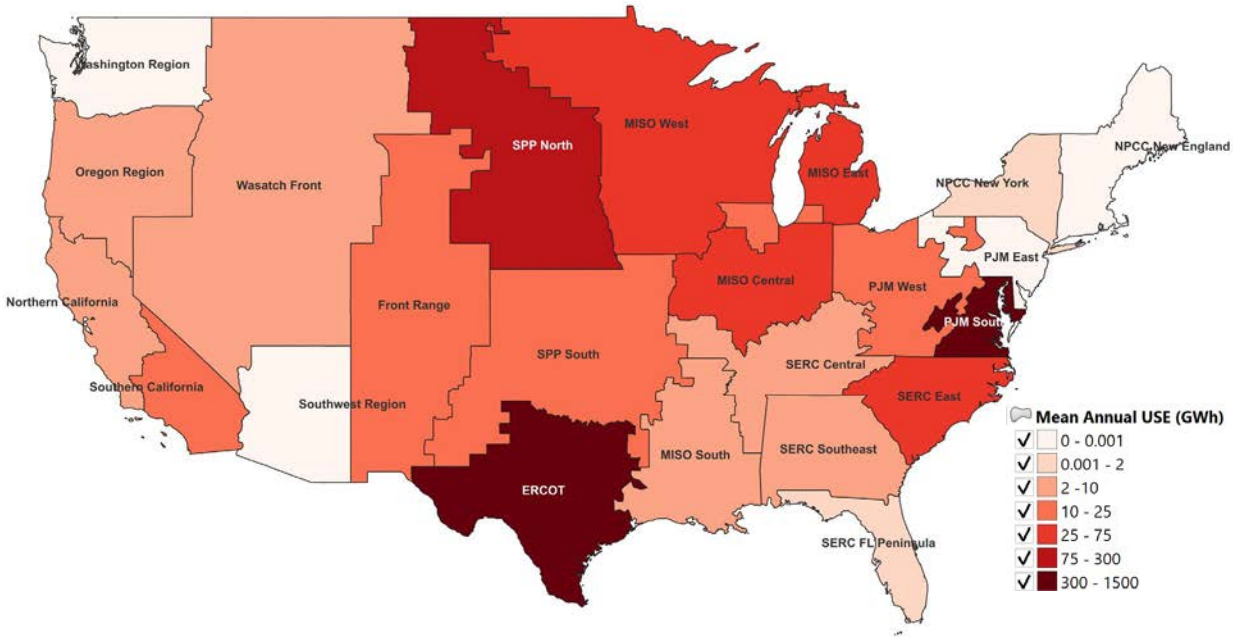


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures**: All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH)**: Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity**: Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy**: Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events**: Most regions experienced ≥3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways**: Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance**: Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures**:

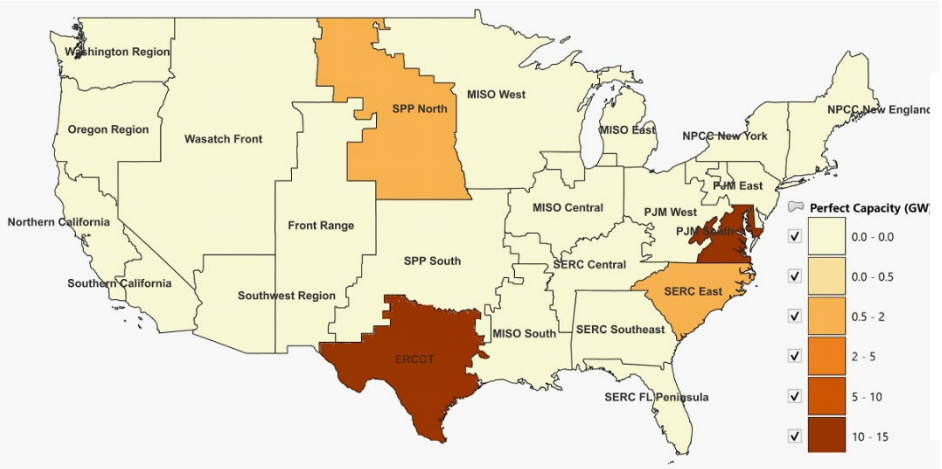
- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- **SERC-East**: Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as “perfect capacity,” this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.



	2024-Current System (MW)	2030-No Plant Closures (MW)
PJM	2400	10,500
SERC-E		500
SPP-N		1,500
ERCOT	1600	10500
Total	4000	23000

Perfect Capacity/Additions

Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS[13] model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)[14] including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,[15] it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS[16] base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

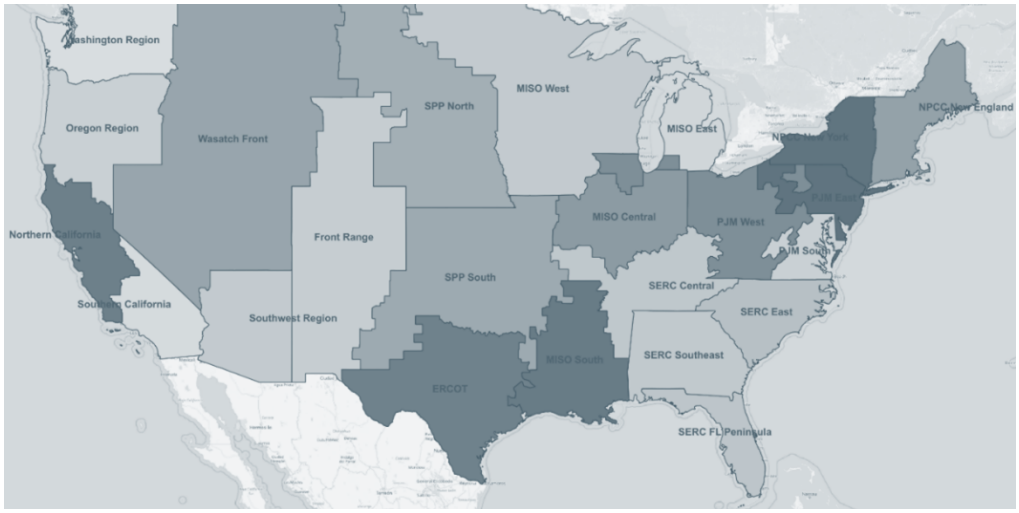


Figure 5. TPRs used in NERC ITCS

13. Energy Exemplar, "PLEXOS," https://www.energyexemplar.com/plexos.
14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.
15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").
16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.[17] Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.

- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.[18]

- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.

- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).

- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.

- **Transfer Capabilities and Imports/Exports -** Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.
18. See ITCS Final Report, Appendix G, for outage and derate methods.

  - Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.

  - To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See "Outputs" in the appendix for more details.

  - To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of $1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.

- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.
- **Demand Response –** Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for "Controllable and Dispatchable Demand Response – Available", or firm, controllable DR capacity.
- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:

  1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.[19]

  2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.

- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
    - *Normalized USE (percentage %):* The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.[20]
    - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
    - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
    - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
    - *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.

- *Max Consecutive LOLH (hours)*[21]: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

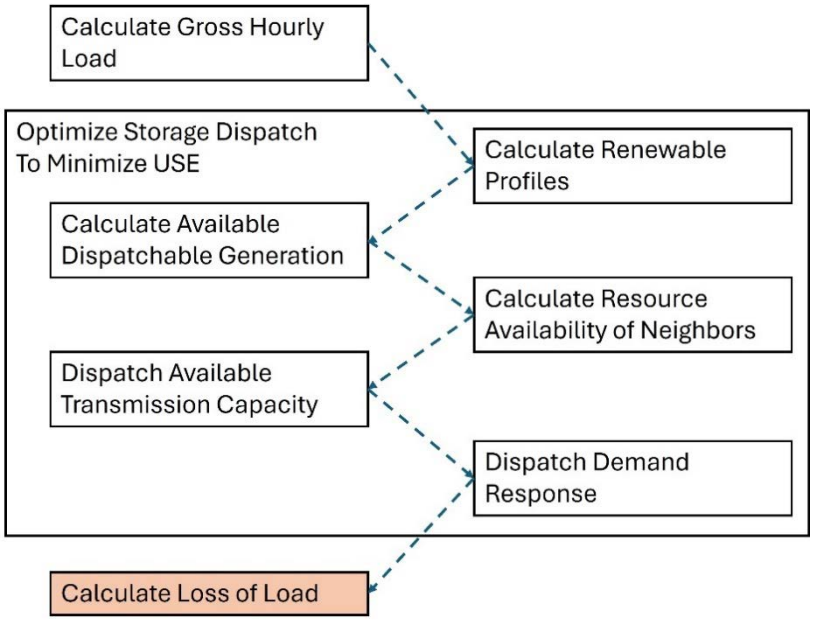


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.

- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.

- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.

- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 108 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

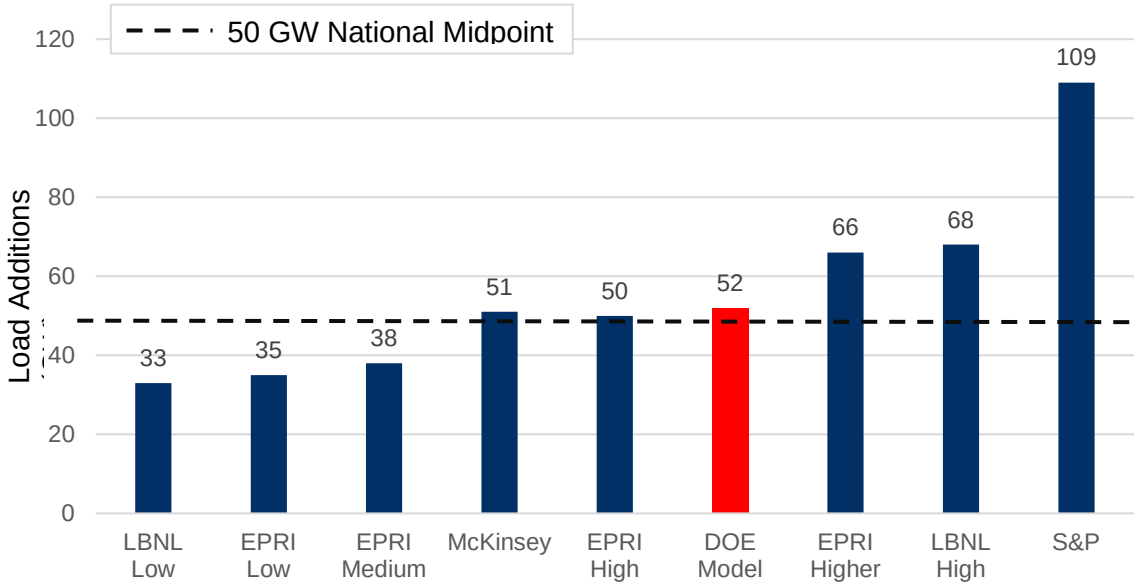


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 2 above displays a benchmark reflecting the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models.

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

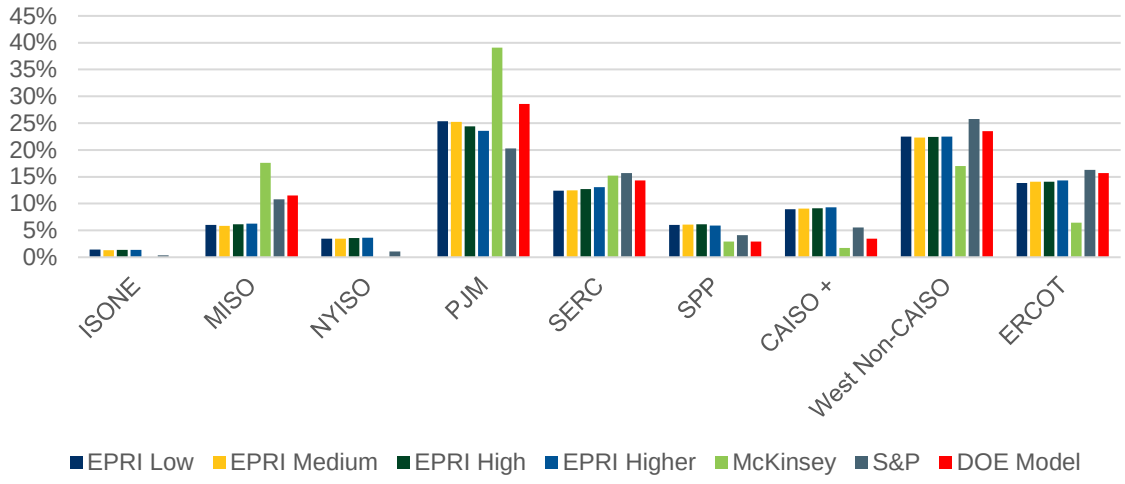


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

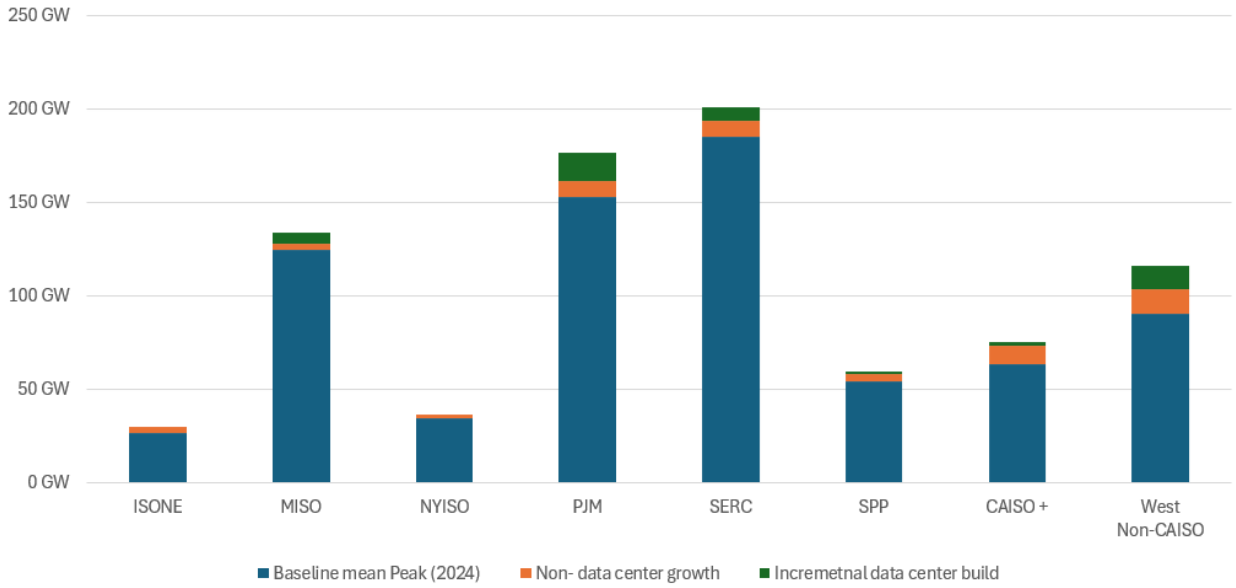


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.[22] Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%. [23]

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the "perfect capacity" to be as small as possible while reaching NUSE values below 0.002% in all regions.[24] As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term "expected unserved energy" because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, "Resource Adequacy Metrics and Criteria Roadmap," December 2024. https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf.

24. NERC, "Evolving Criteria for a Sustainable Power Grid," July 2024. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO[25]

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

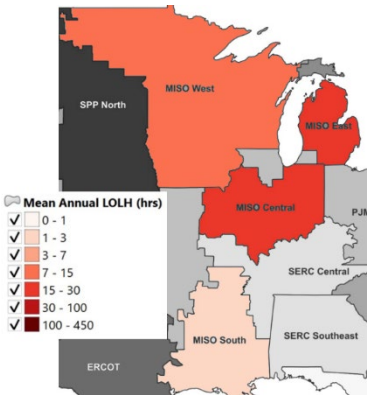


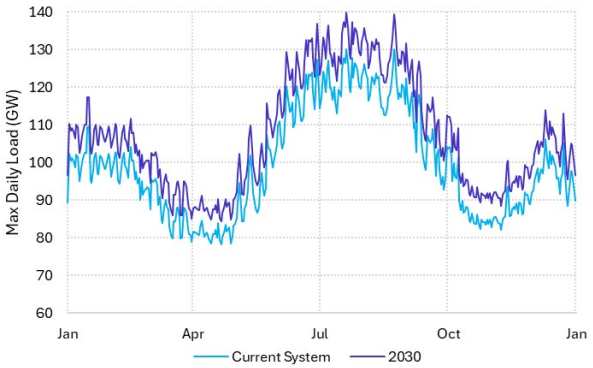
Table 2. Summary of MISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	**130,136**	**139,846**

Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.[26] In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	**207,319**	**196,049**	**228,393**

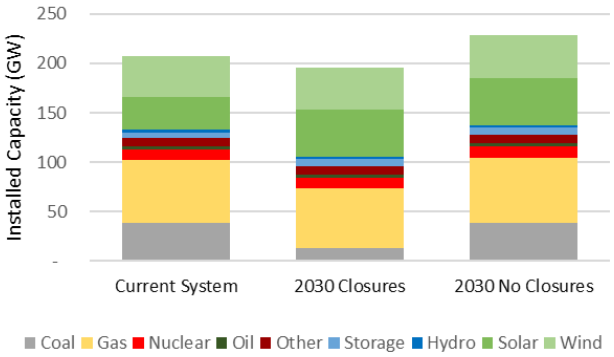


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**37,914**	**64,194**	**11,127**	**2,867**	**8,717**	**5,427**	**2,533**	**32,826**	**41,715**	**207,319**
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	**71,612**
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	**51,982**
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	**54,511**
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	**29,213**
Additions	**0**	**2,535**	**0**	**330**	**0**	**1,929**	**0**	**14,354**	**1,926**	**21,074**
MISO-W	0	537	0	172	0	374	0	3,552	1,358	**5,993**
MISO-C	0	407	0	57	0	934	0	5,103	339	**6,841**
MISO-S	0	1,226	0	68	0	9	0	3,868	27	**5,199**
MISO-E	0	364	0	34	0	611	0	1,831	201	**3,042**
Closures	**(24,913)**	**(6,597)**	**0**	**(324)**	**(140)**	**(16)**	**(83)**	**0**	**(272)**	**(32,345)**
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	**(10,152)**
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	**(11,088)**
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	**(6,954)**
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	**(4,150)**

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

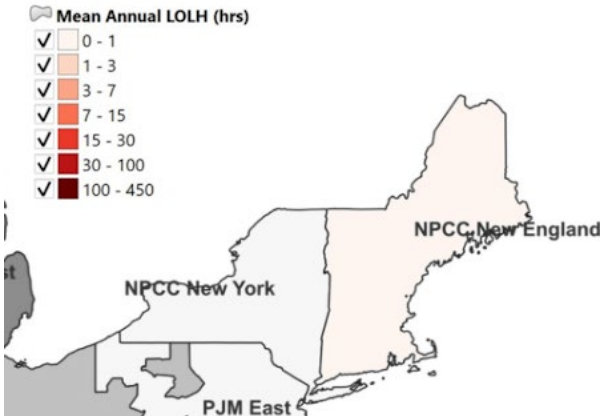
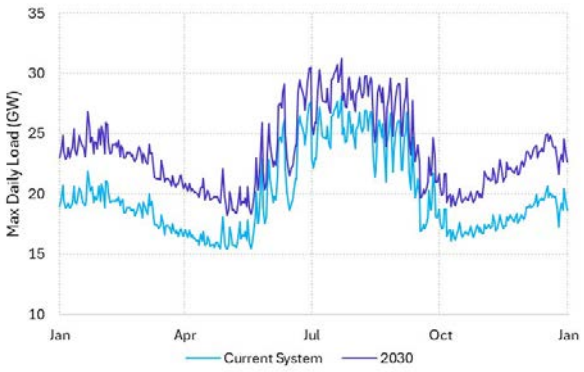


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	**28,128**	**31,261**

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	**39,979**	**42,845**	**45,534**

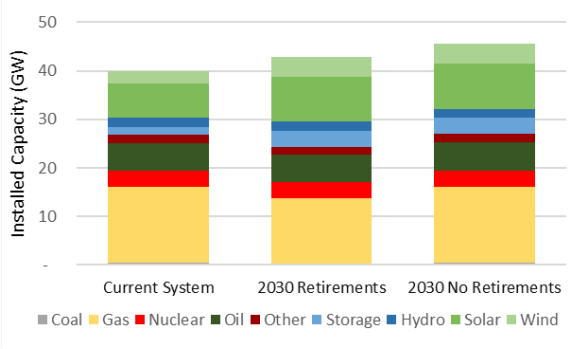


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**541**	**15,494**	**3,331**	**5,710**	**1,712**	**1,628**	**1,911**	**7,099**	**2,553**	**39,979**
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	**39,979**
Additions	**0**	**90**	**0**	**181**	**0**	**1,607**	**0**	**2,183**	**1,495**	**5,555**
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	**5,555**
Closures	**(534)**	**(1,875)**	**0**	**(203)**	**(77)**	**0**	**0**	**0**	**0**	**(2,690)**
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	**(2,690)**

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

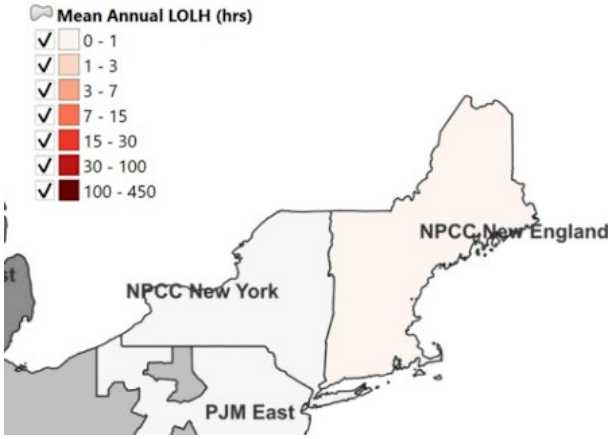
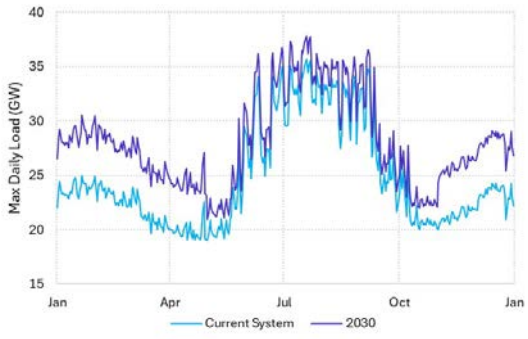


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
NYISO	35,669	37,844
Total	**35,669**	**37,844**

Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	**45,924**	**50,396**	**51,444**

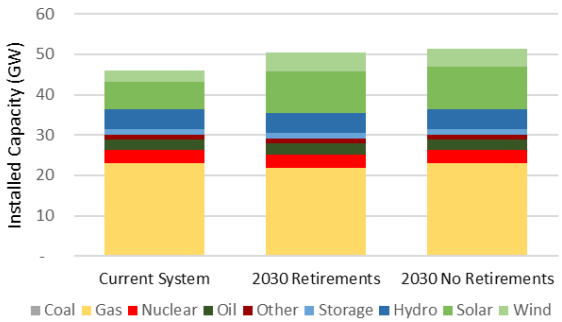


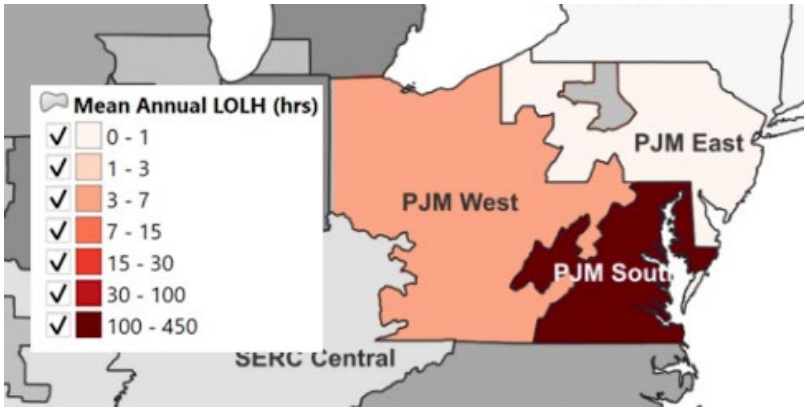
Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO's generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**0**	**22,937**	**3,330**	**2,631**	**1,194**	**1,460**	**4,915**	**6,749**	**2,706**	**45,924**
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	**45,924**
Additions	**0**	**0**	**0**	**15**	**0**	**0**	**0**	**3,604**	**1,902**	**5,521**
NYISO	0	0	0	15	0	0	0	3,604	1,902	**5,521**
Closures	**0**	**(1,030)**	**0**	**(19)**	**0**	**0**	**0**	**0**	**0**	**(1,049)**
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	**(1,049)**

2.4 PJM



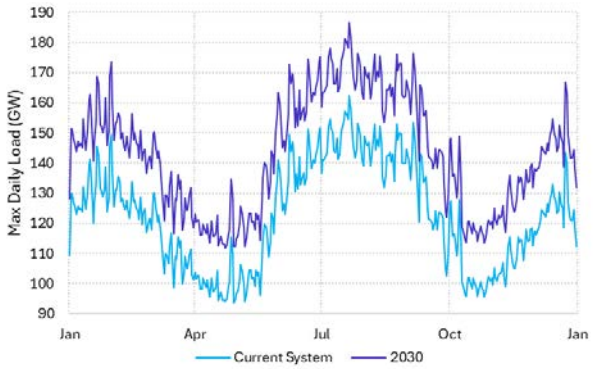
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

Table 8. Summary of PJM Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	**162,269**	**186,627**

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	**214,638**	**236,798**	**253,504**

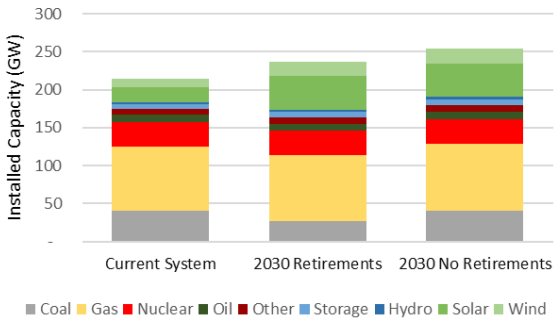


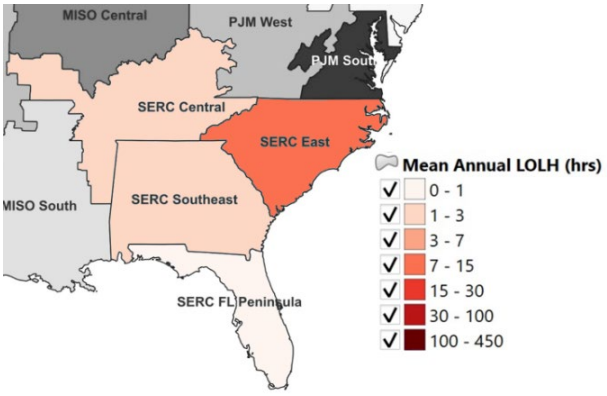
Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**39,915**	**84,381**	**32,535**	**9,875**	**8,248**	**5,400**	**3,071**	**19,495**	**11,718**	**214,638**
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	**114,467**
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	**39,951**
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	**60,221**
Additions	**0**	**4,499**	**0**	**32**	**317**	**1,938**	**0**	**24,991**	**7,089**	**38,866**
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	**21,343**
PJM-S	0	802	0	13	102	726	0	8,856	218	**10,717**
PJM-E	0	1,615	0	13	81	357	0	3,958	783	**6,806**
Closures	**(13,253)**	**(1,652)**	**0**	**(1,790)**	**(11)**	**0**	**0**	**0**	**0**	**(16,706)**
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	**(12,710)**
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	**(1,817)**
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	**(2,179)**

2.5 SERC



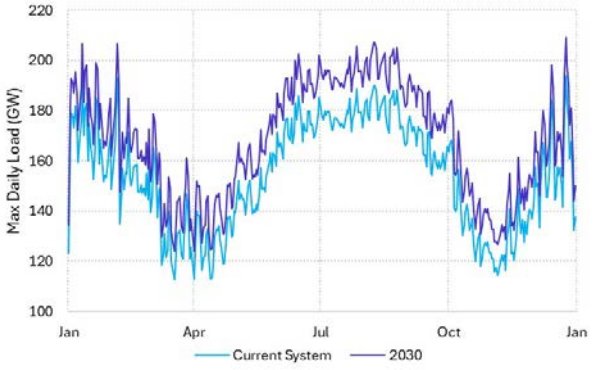
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

Table 10. Summary of SERC Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	**193,654**	**209,269**

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	**253,680**	**260,423**	**279,285**

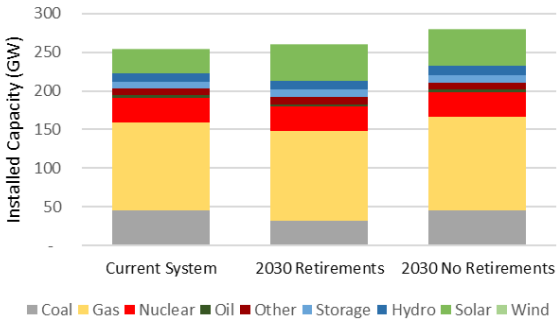


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**45,747**	**113,334**	**31,702**	**4,063**	**8,779**	**7,469**	**11,425**	**30,180**	**982**	**253,680**
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	**53,978**
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	**67,073**
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	**72,714**
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	**59,914**
Additions	**0**	**6,898**	**0**	**0**	**381**	**2,254**	**0**	**16,073**	**0**	**25,606**
SERC-C	0	4,831	0	0	0	80	0	771	0	**5,682**
SERC-SE	0	906	0	0	19	0	0	3,135	0	**4,059**
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	**13,459**
SERC-E	0	0	0	0	144	504	0	1,757	0	**2,405**
Closures	**(14,075)**	**(4,115)**	**0**	**(672)**	**0**	**0**	**0**	**0**	**0**	**(18,862)**
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	**(5,646)**
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	**(5,460)**
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	**(3,046)**
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	**(4,710)**

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

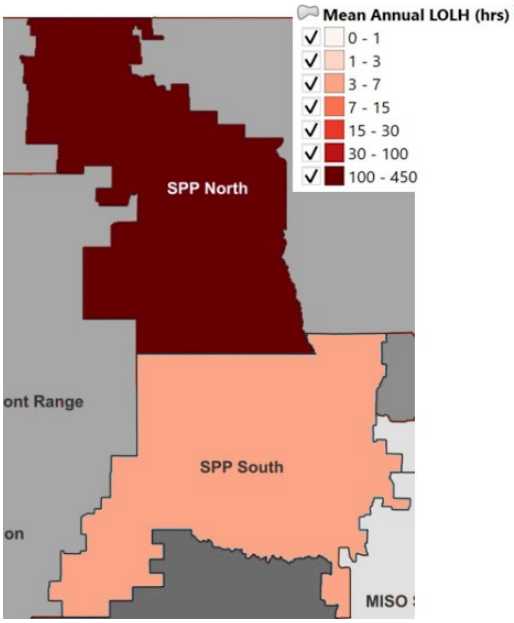
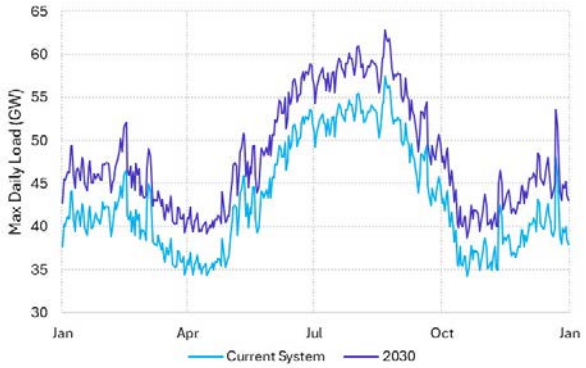


Table 12. Summary of SPP Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).



Subregion	2024	2030
SPP-N	12,668	14,676
SPP-S	44,898	48,337
Total	**57,449**	**62,891**

Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	**95,142**	**103,130**	**110,449**

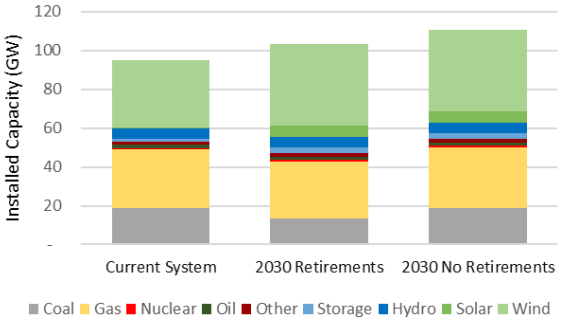


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**18,919**	**30,003**	**769**	**1,626**	**1,718**	**1,522**	**5,123**	**774**	**34,689**	**95,142**
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	**20,065**
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	**75,078**
Additions	**0**	**1,094**	**0**	**7**	**462**	**1,390**	**0**	**5,288**	**7,066**	**15,306**
SPP-N	0	126	0	2	114	11	0	633	1,434	**2,320**
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	**12,987**
Closures	**(5,530)**	**(1,732)**	**0**	**(56)**	**0**	**0**	**0**	**0**	**0**	**(7,318)**
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	**(1,705)**
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	**(5,613)**

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system's vulnerability to high load and low renewable output periods.

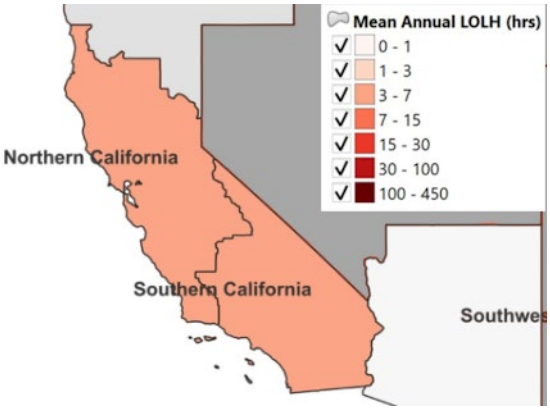
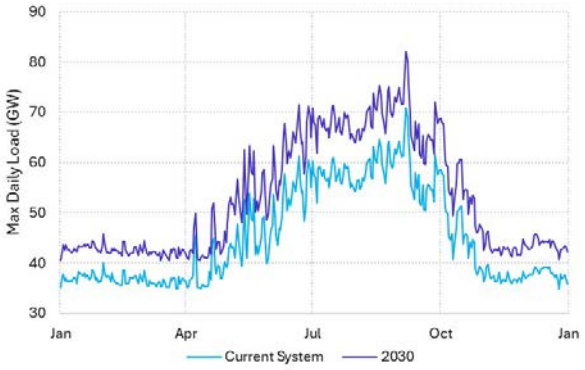


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+'s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	**70,815**	**82,146**

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	**116,925**	**122,938**	**130,809**

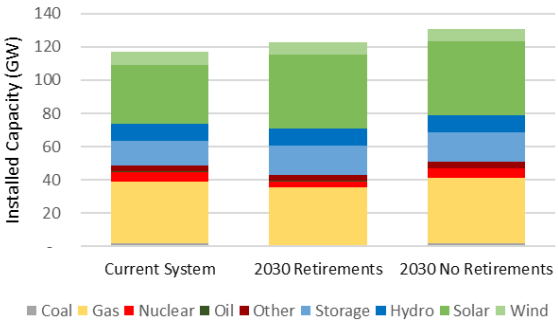


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**1,816**	**37,434**	**5,582**	**185**	**3,594**	**14,670**	**10,211**	**35,661**	**7,773**	**116,925**
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	**47,059**
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	**69,866**
Additions	**0**	**2,126**	**0**	**0**	**92**	**3,161**	**0**	**8,507**	**0**	**13,885**
CALI-N	0	735	0	0	44	757	0	3,906	0	**5,442**
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	**8,442**
Closures	**(1,800)**	**(3,771)**	**(2,300)**	**0**	**0**	**0**	**0**	**0**	**0**	**(7,871)**
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	**(3,604)**
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	**(4,267)**

2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

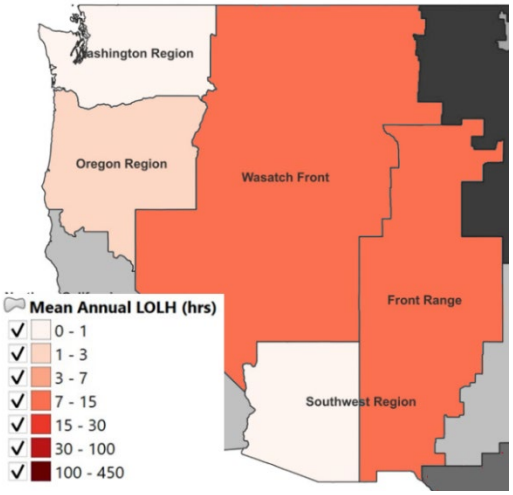
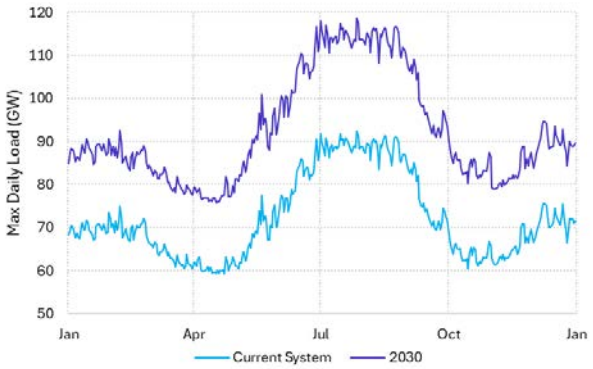


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	17.8	-	-
Normalized Unserved Energy (%)	-	0.0032	-	-
Unserved Load (MWh)	-	21,785	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	47	-	-
Normalized Unserved Load (%)	-	0.0098	-	-
Unserved Load (MWh)	-	66,248	-	-
Max Unserved Load (MW)	-	5,071	-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	**92,448**	**118,657**

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	**177,929**	**193,485**	**206,908**

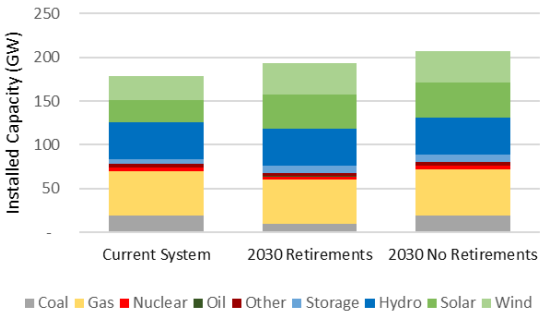


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**19,850**	**49,969**	**3,820**	**644**	**4,114**	**5,104**	**42,476**	**24,652**	**27,298**	**177,929**
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	**35,207**
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	**19,068**
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	**42,335**
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	**42,746**
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	**38,572**
Additions	**0**	**2,320**	**0**	**1**	**8**	**2,932**	**0**	**14,759**	**8,959**	**28,979**
WASHINGTON	0	246	0	0	0	109	0	1,059	952	**2,366**
OREGON	0	246	0	0	0	150	0	1,399	1,218	**3,013**
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	**6,823**
WASATCH	0	884	0	0	7	233	0	4,946	1,435	**7,505**
FRONT R	0	634	0	0	0	102	0	3,779	4,756	**9,271**
Closures	**(9,673)**	**(2,540)**	**0**	**(6)**	**(311)**	**(170)**	**(627)**	**0**	**(95)**	**(13,422)**
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	**(986)**
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	**(392)**
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	**(2,136)**
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	**(5,077)**
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	**(4,832)**

2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

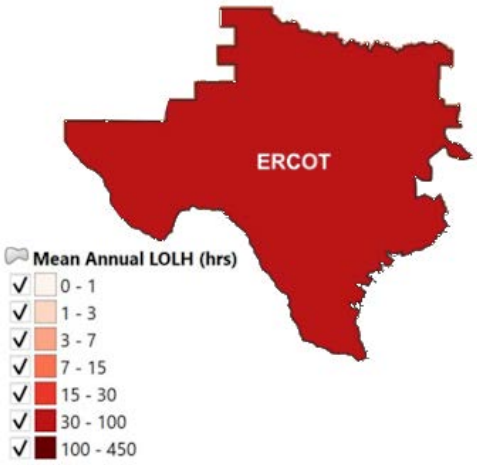
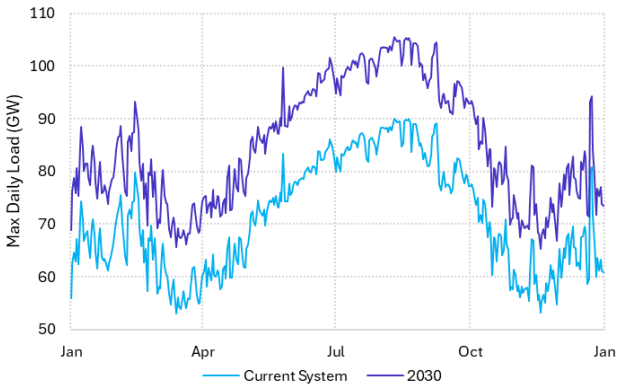


Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	**90,075**	**105,485**

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	**157,490**	**208,894**	**212,916**

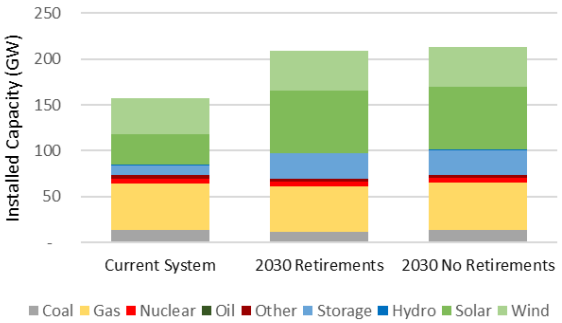


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**13,568**	**50,889**	**4,973**	**10**	**3,627**	**10,720**	**583**	**33,589**	**39,532**	**157,490**
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	**157,490**
Additions	**0**	**569**	**0**	**0**	**0**	**16,538**	**0**	**34,681**	**3,638**	**55,426**
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	**55,426**
Closures	**(2,000)**	**(2,022)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(4,022)**
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	**(4,022)**

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.[27] This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs[28], the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities[29] and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

27. NERC, “Interregional Transfer Capability Study (ITCS).” https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, “2024 Long-Term Reliability Assessment,” December, 2024, 24. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

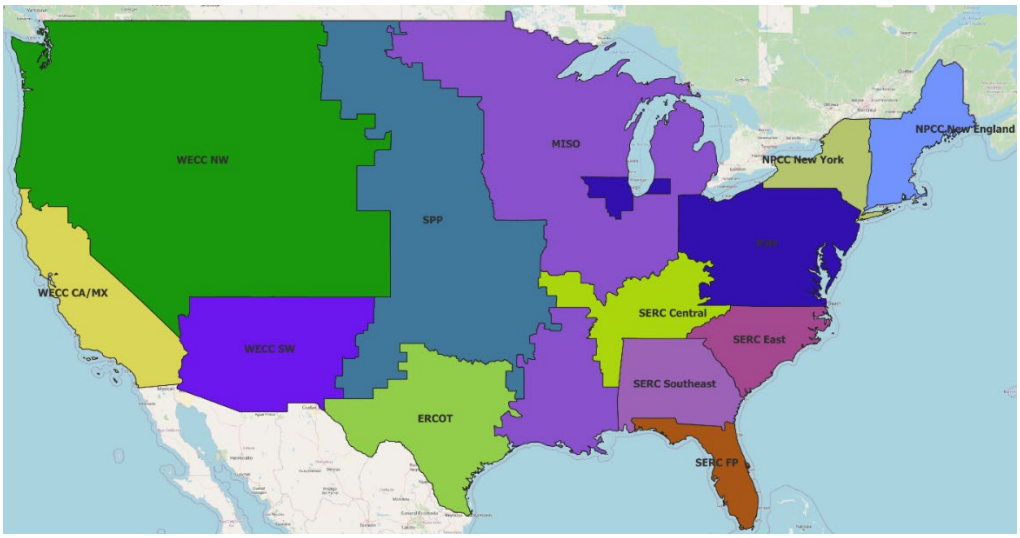


Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.[30] Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \quad \textit{(Equation.1)}$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R. The denominator is the total capacity of that fuel type across all ITCS regions mapped to R.

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, "Regional Energy Development System," https://www.nrel.gov/analysis/reeds/.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Exsting + Tier 1			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**330,342**	**82,793**	**26,771**	**3,624**	**-**	**991**	**19,607**	**3,298**	**28,980**	**72,757**	**94,364**	**25,753**	**24,367**	**856,682**
	ISONE	**Total**	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO	**Total**	**37,914**	**64,194**	**11,127**	**2,867**	**613**	**-**	**329**	**4,396**	**1,031**	**2,533**	**29,777**	**41,715**	**7,775**	**3,049**	**207,319**
		MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
		MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
		MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
		MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO	**Total**	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM	**Total**	**39,915**	**84,381**	**32,535**	**9,875**	**851**	**-**	**-**	**5,062**	**338**	**3,071**	**10,892**	**11,718**	**7,397**	**8,603**	**214,638**
		PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
		PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
		PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC	**Total**	**45,747**	**113,334**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**768**	**11,425**	**26,959**	**982**	**7,707**	**3,221**	**253,680**
		SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
		SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
		SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP	**Total**	**18,919**	**30,003**	**769**	**1,626**	**20**	**-**	**345**	**477**	**1,044**	**5,123**	**703**	**34,689**	**1,353**	**71**	**95,142**
		SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
		SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	**Total**		**13,568**	**50,889**	**4,973**	**10**	**163**	**-**	**-**	**-**	**10,720**	**583**	**31,058**	**39,532**	**3,464**	**2,531**	**157,490**
	ERCOT	**Total**	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	**Total**		**21,666**	**87,403**	**9,403**	**829**	**1,565**	**4,093**	**106**	**4,536**	**15,238**	**52,687**	**44,042**	**35,071**	**1,944**	**16,271**	**294,854**
	CAISO+	**Total**	**1,816**	**37,434**	**5,582**	**185**	**726**	**2,004**	**35**	**3,514**	**11,156**	**10,211**	**25,614**	**7,773**	**829**	**10,047**	**116,925**
		CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
		CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC	**Total**	**19,850**	**49,969**	**3,820**	**644**	**839**	**2,089**	**71**	**1,022**	**4,082**	**42,476**	**18,428**	**27,298**	**1,115**	**6,224**	**177,929**
		WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
		OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
		SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
		WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
		FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
		Total	**178,268**	**468,635**	**97,169**	**27,610**	**5,353**	**4,093**	**1,096**	**24,144**	**29,256**	**82,249**	**147,856**	**168,966**	**31,161**	**43,169**	**1,309,026**

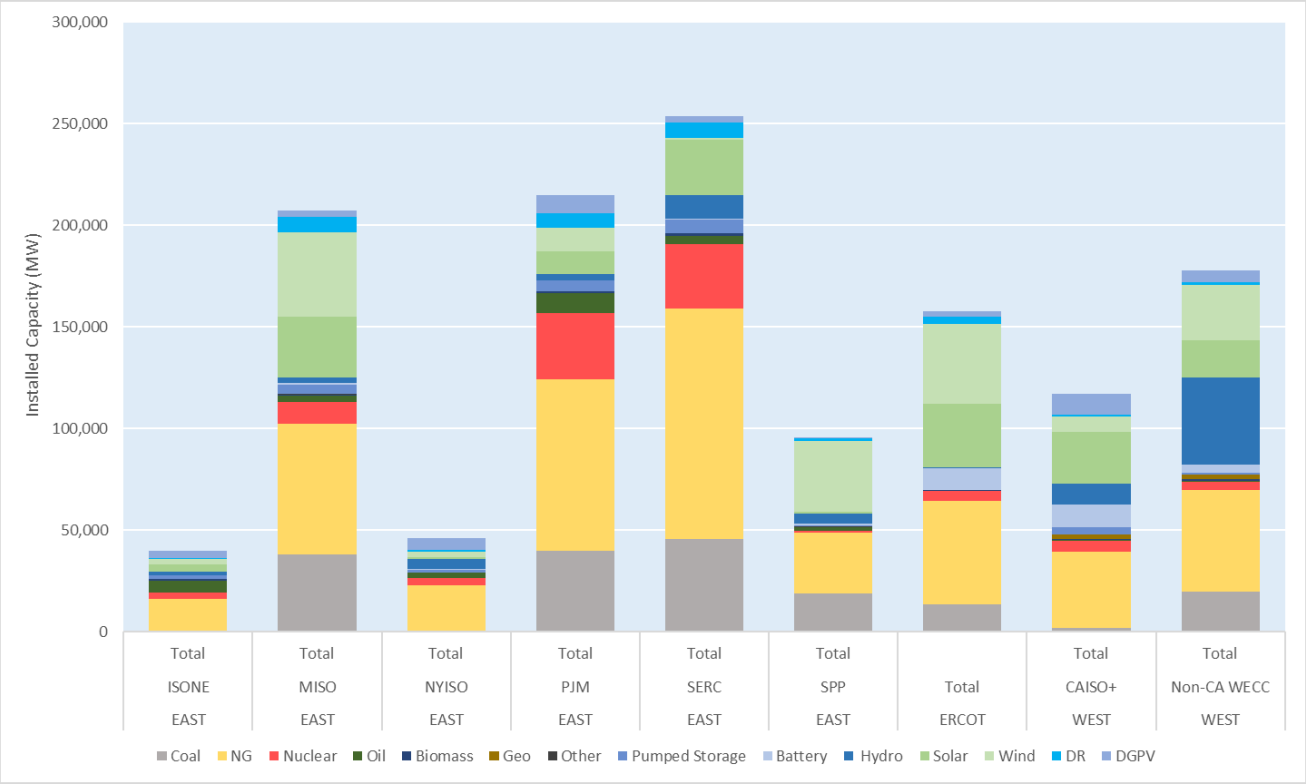


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

(i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

(i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

(ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

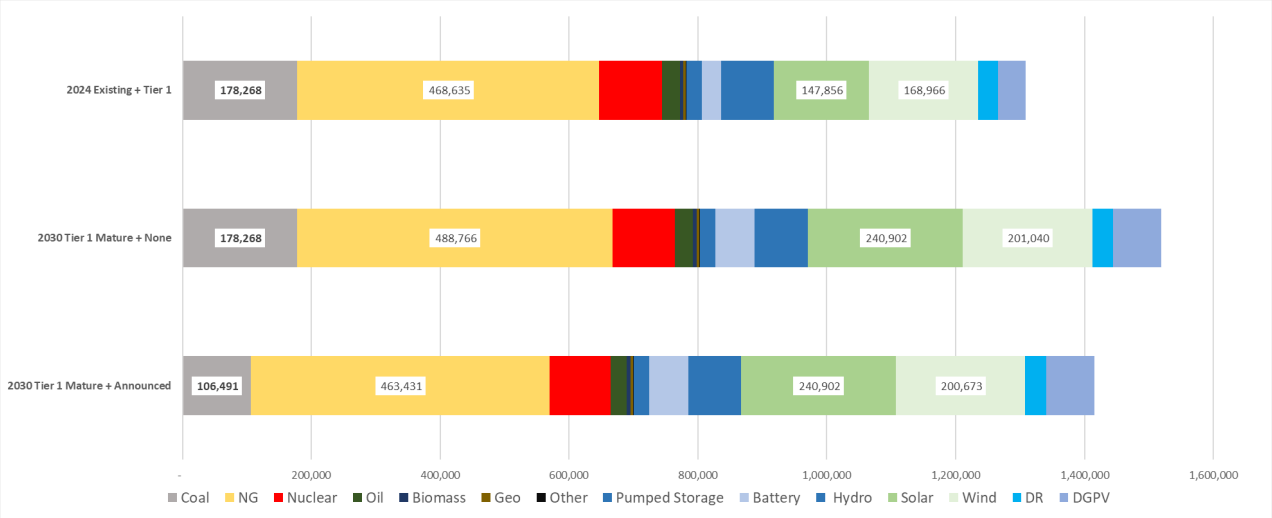


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**84,730**	**328,457**	**82,793**	**24,272**	**3,473**	**-**	**991**	**19,591**	**12,415**	**28,897**	**126,849**	**113,568**	**26,837**	**36,768**	**889,641**
	ISONE	**Total**	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO	**Total**	**13,001**	**60,132**	**11,127**	**2,873**	**473**	**-**	**329**	**4,380**	**2,960**	**2,450**	**44,132**	**43,369**	**7,775**	**3,049**	**196,049**
		MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
		MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
		MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
		MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO	**Total**	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM	**Total**	**26,662**	**87,228**	**32,535**	**8,117**	**917**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**236,798**
		PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
		PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
		PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC	**Total**	**31,672**	**116,117**	**31,702**	**3,391**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**260,423**
		SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
		SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
		SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
		SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP	**Total**	**13,389**	**29,365**	**769**	**1,576**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**103,130**
		SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
		SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	**Total**		**11,568**	**49,436**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**208,894**
	ERCOT	**Total**	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	**Total**		**10,193**	**85,538**	**7,103**	**823**	**1,427**	**3,983**	**106**	**4,366**	**21,330**	**52,060**	**51,648**	**43,935**	**1,981**	**31,931**	**316,424**
	CAISO+	**Total**	**16**	**35,789**	**3,282**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**122,938**
		CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
		CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC	**Total**	**10,177**	**49,749**	**3,820**	**639**	**701**	**1,924**	**71**	**852**	**7,014**	**41,849**	**24,536**	**36,162**	**1,115**	**14,876**	**193,485**
		WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
		OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
		SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
		WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
		FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
		Total	**106,491**	**463,431**	**94,869**	**25,106**	**5,063**	**3,983**	**1,096**	**23,958**	**61,003**	**81,539**	**240,902**	**200,673**	**32,282**	**74,563**	**1,414,959**

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**345,459**	**82,793**	**27,336**	**3,701**	**-**	**991**	**19,607**	**12,415**	**28,980**	**126,849**	**113,840**	**26,837**	**36,768**	**968,610**
	ISONE	**Total**	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	**Total**	**37,914**	**66,729**	**11,127**	**3,197**	**613**	**-**	**329**	**4,396**	**2,960**	**2,533**	**44,132**	**43,641**	**7,775**	**3,049**	**228,393**
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	**Total**	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	**Total**	**39,915**	**88,880**	**32,535**	**9,907**	**928**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**253,504**
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	**Total**	**45,747**	**120,232**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**279,285**
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	**Total**	**18,919**	**31,098**	**769**	**1,632**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**110,449**
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	**Total**		**13,568**	**51,458**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**212,916**
	ERCOT	**Total**	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	**Total**		**21,666**	**91,849**	**9,403**	**829**	**1,565**	**4,156**	**106**	**4,536**	**21,330**	**52,687**	**51,648**	**44,030**	**1,981**	**31,931**	**337,717**
	CAISO+	**Total**	**1,816**	**39,560**	**5,582**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**130,809**
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	**Total**	**19,850**	**52,289**	**3,820**	**645**	**839**	**2,097**	**71**	**1,022**	**7,014**	**42,476**	**24,536**	**36,257**	**1,115**	**14,876**	**206,908**
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
		Total	**178,268**	**488,766**	**97,169**	**28,175**	**5,429**	**4,156**	**1,096**	**24,144**	**61,003**	**82,249**	**240,902**	**201,040**	**32,282**	**74,563**	**1,519,243**

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.[1–17]

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a "learning rate" scales each tree's contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

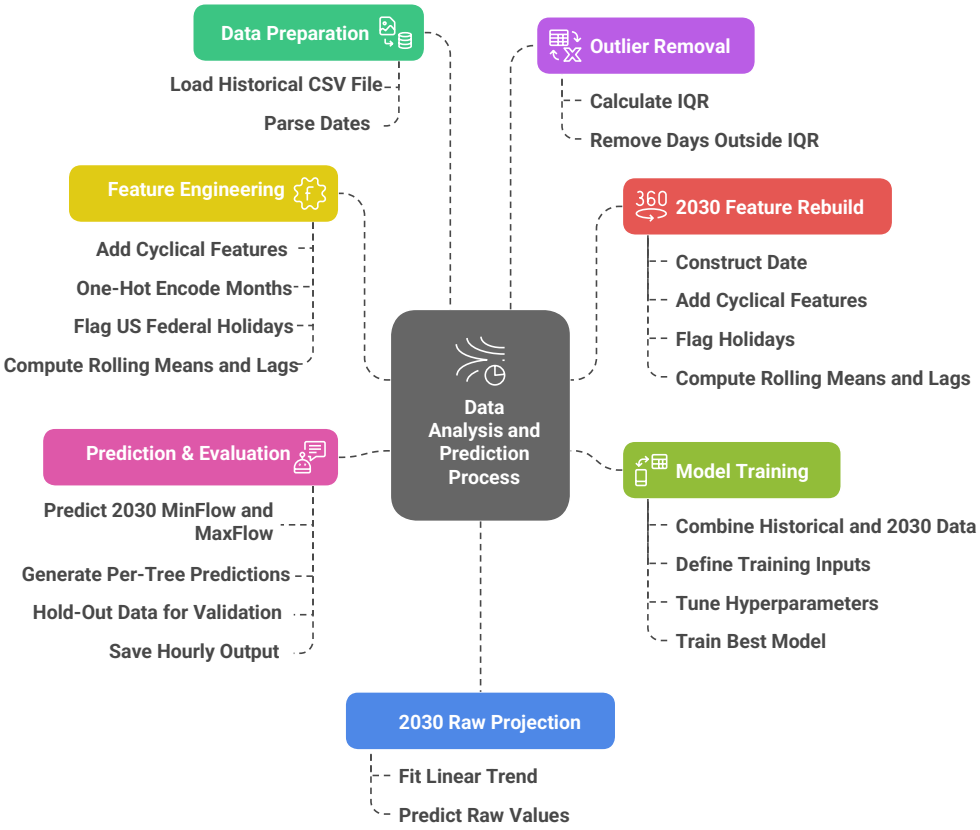


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year's MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

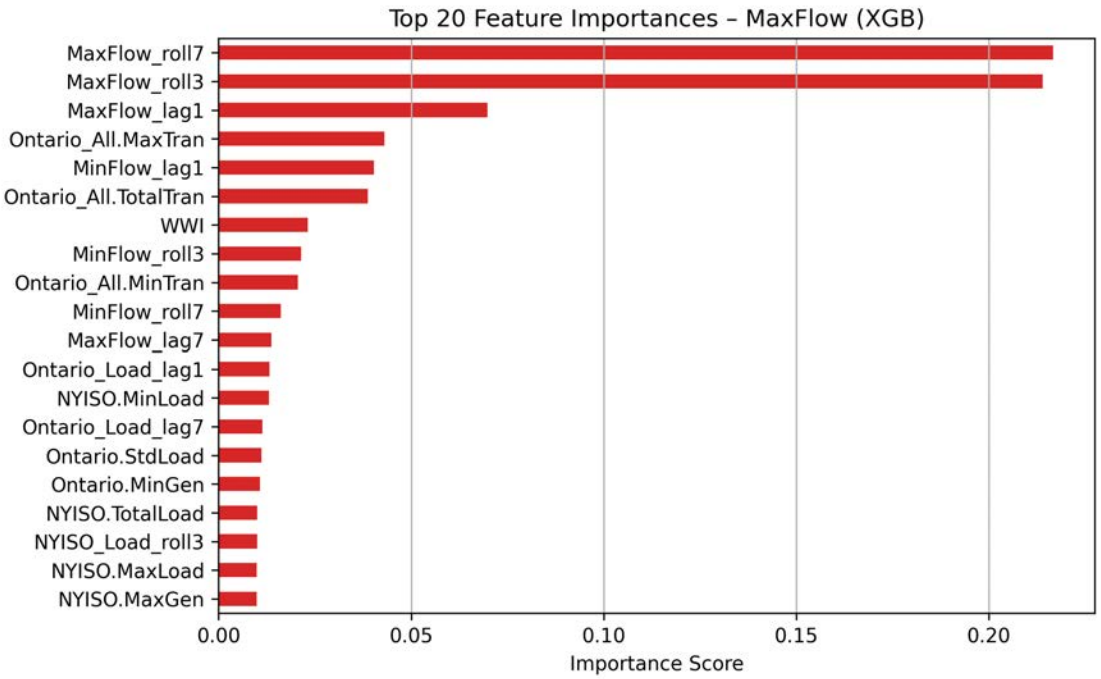


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

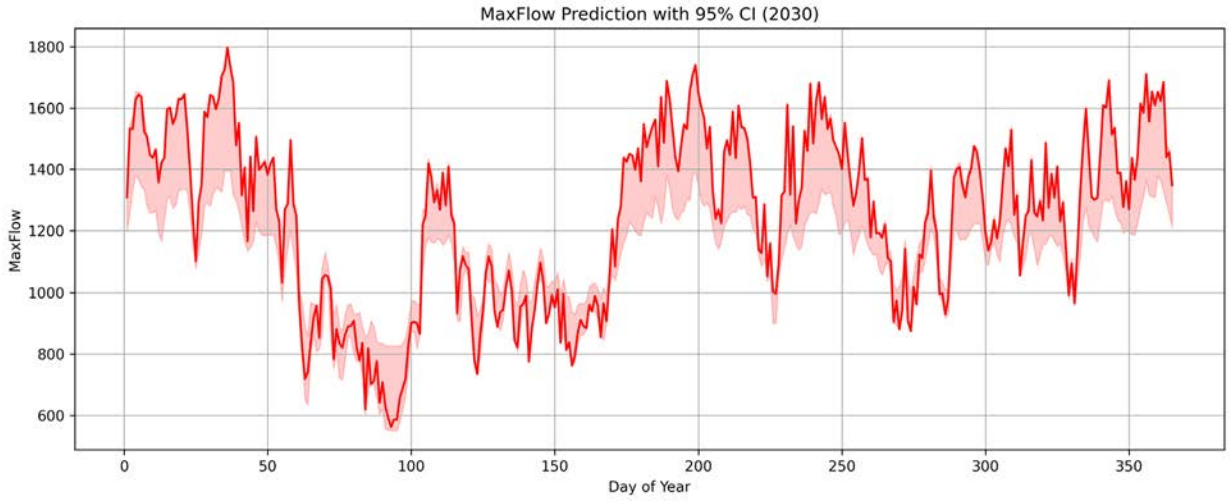


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model's reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

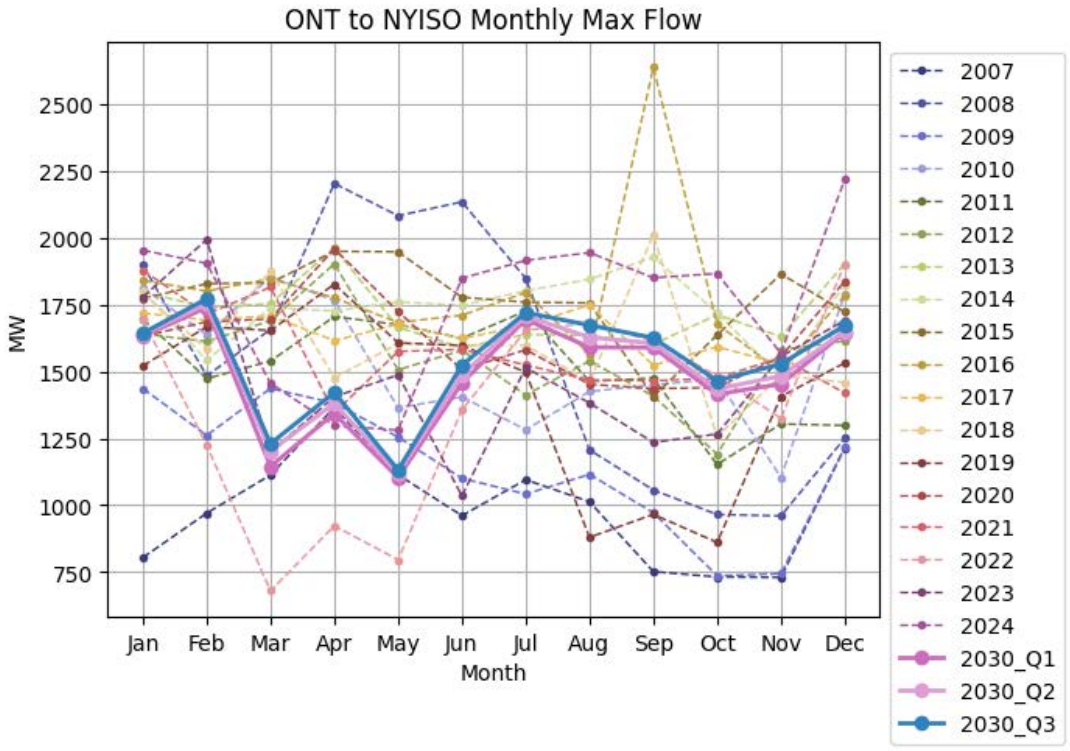


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ±150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load,

generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

(iii) Pacific Northwest to British Columbia

(iv) Alberta to Montana

(v) Manitoba to MISO West

(vi) Ontario to MISO West

(vii) Ontario to MISO East

(viii) Ontario to New York

(ix) Hydro-Quebec to New York

(x) Hydro-Quebec to New England

(xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

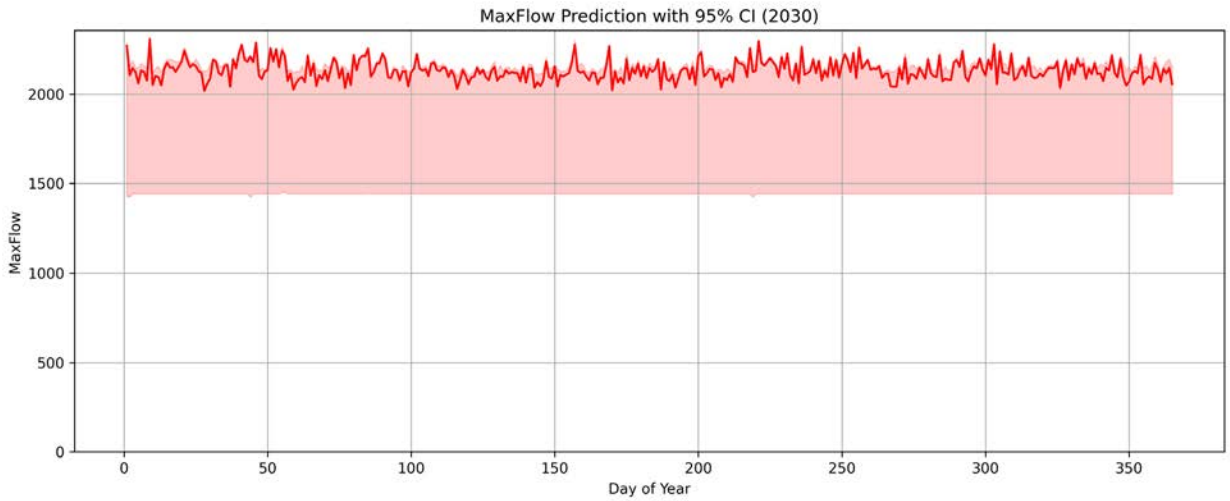


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

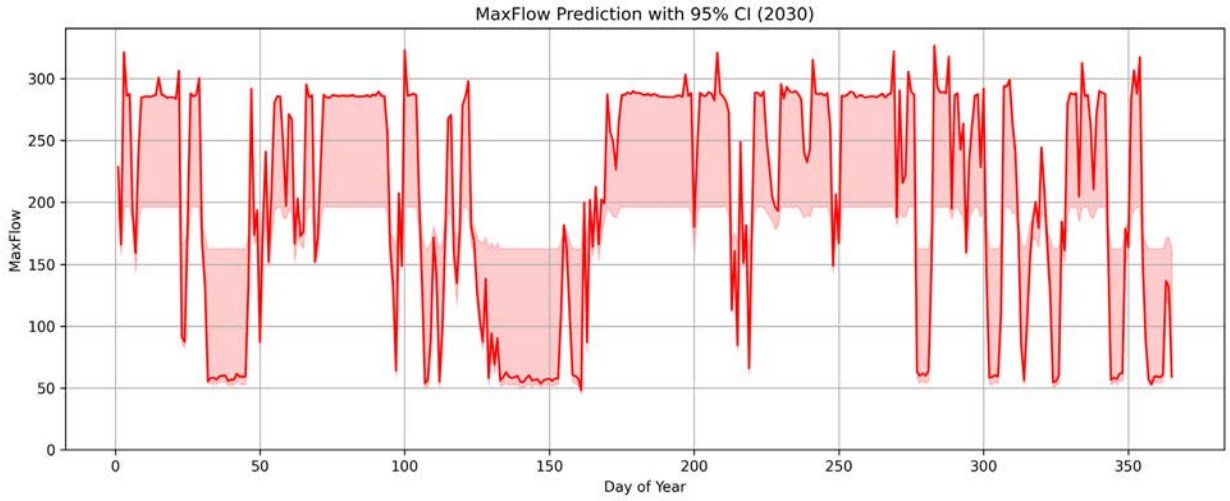


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

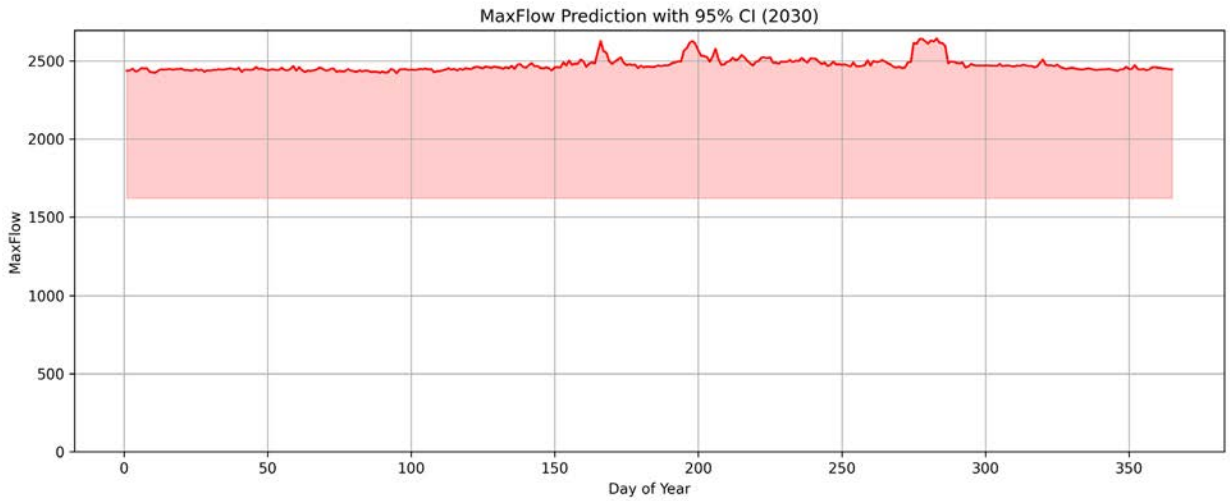


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

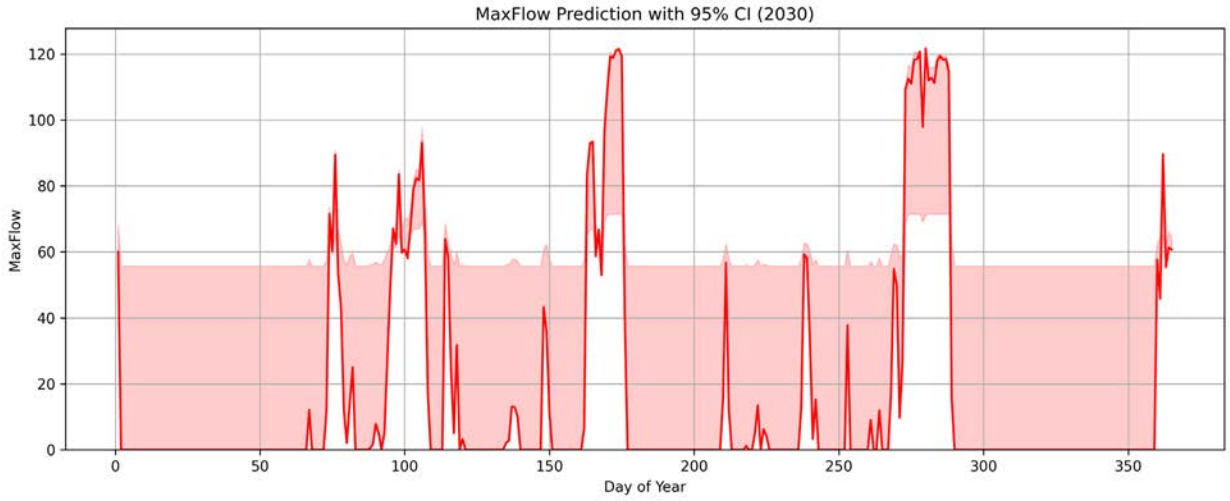


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

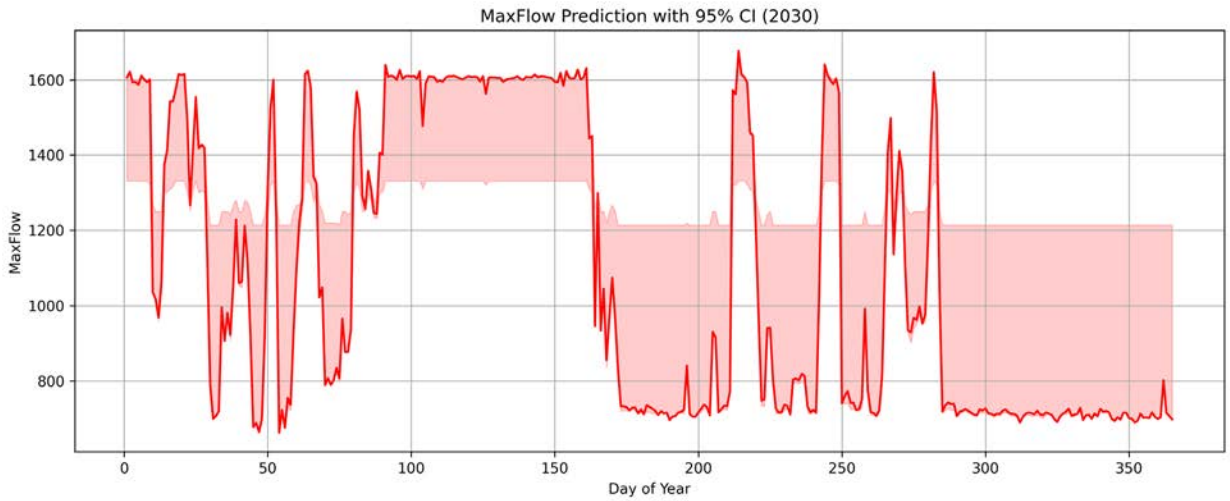


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

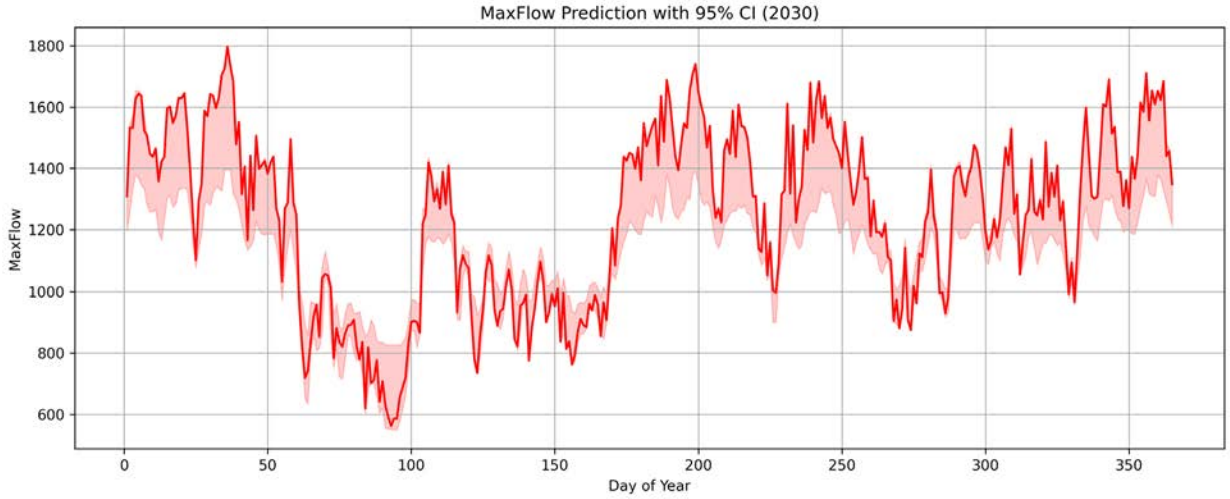


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

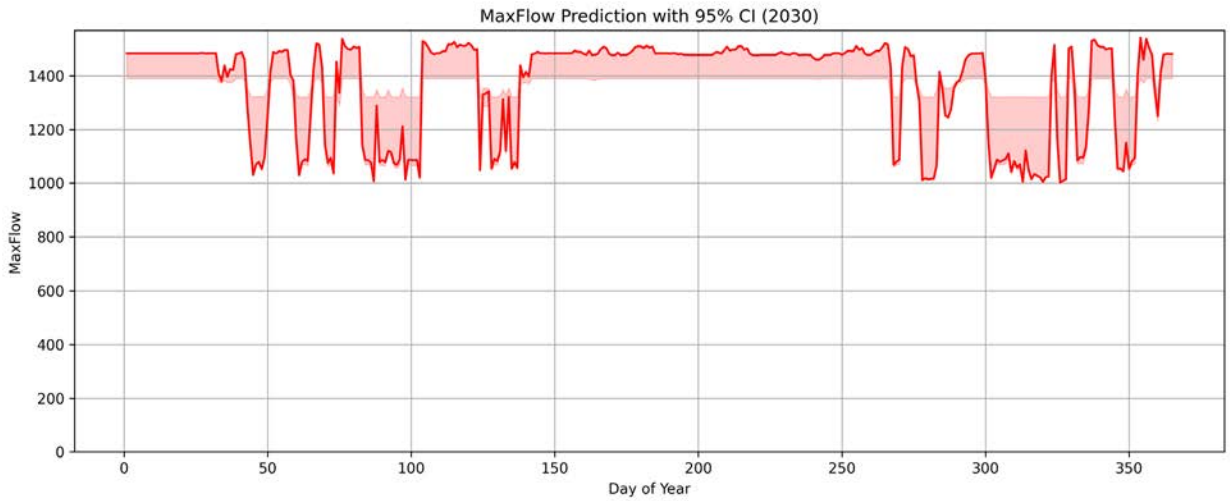


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

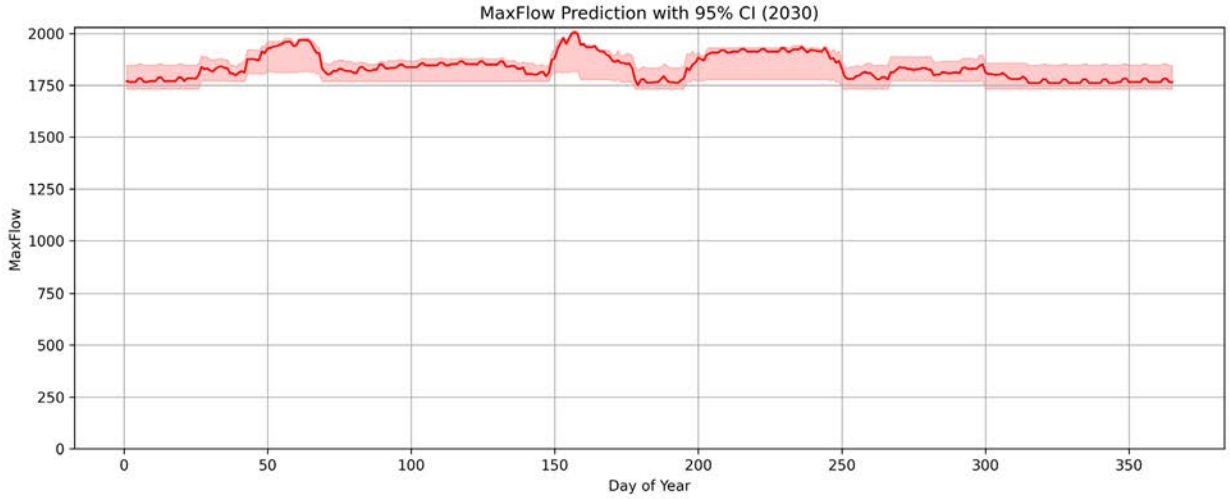


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

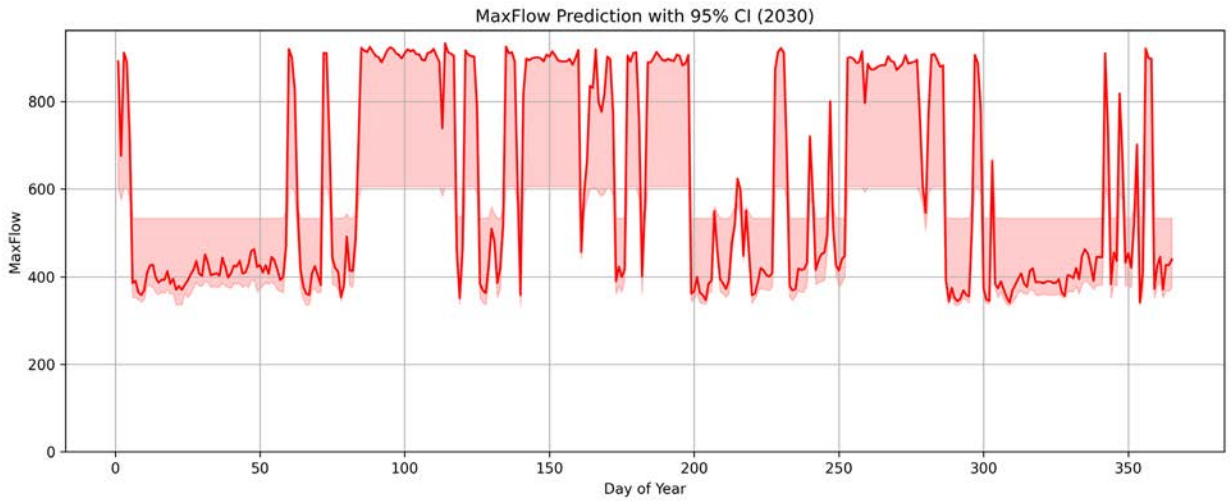


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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EO 14262

Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents 15521

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose.* The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. *Policy.* It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. *Addressing Energy Reliability and Security with Emergency Authority.* (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

(i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;

(ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and

(iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

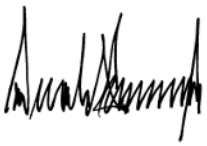
Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025–06381
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U.S. DEPARTMENT of ENERGY

For more information, visit:
energy.gov/topics/reliability

DOE/Publication Number • July, 7 2025

Attachment R

DOE Final EO Report (FINAL JULY 7)

U.S. DEPARTMENT of ENERGY

Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation’s power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored “call to action” for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

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List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, "Declaring a National Emergency (Jan. 20, 2025)," which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE's response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable**. The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring "resource adequacy"). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.
- **Grid Growth Must Match Pace of AI Innovation**. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.
- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030**. The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the "plant closures" scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.
- **Planned Supply Falls Short, Reliability is at Risk**. The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.[1] A deterministic approach[2] simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)[3] and Lawrence Berkeley National Laboratory (LBNL).[4] This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,[5] reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.
2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.
3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, https://www.epri.com/research/products/3002028905.
4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," https://escholarship.org/uc/item/32d6m0d1.
5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics[6] are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

  While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100\ MWh\ (of\ unserved\ energy)}{10{,}000{,}000\ MWh\ (of\ total\ energy\ delivered\ in\ a\ year)} x100 = 0.001\ percent$$

Although the use of NUSE is not standardized in the U.S. today,[7] several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.
7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.[8] To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.[9] This translates into one day of lost load in ten years to meet the 1-in-10 criteria.

- **Magnitude of Outages:** No more than an NUSE of 0.002%.[10] This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures"** case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,[11] which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures"** case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.
9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.
10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.
10. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.

- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.

- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.

- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

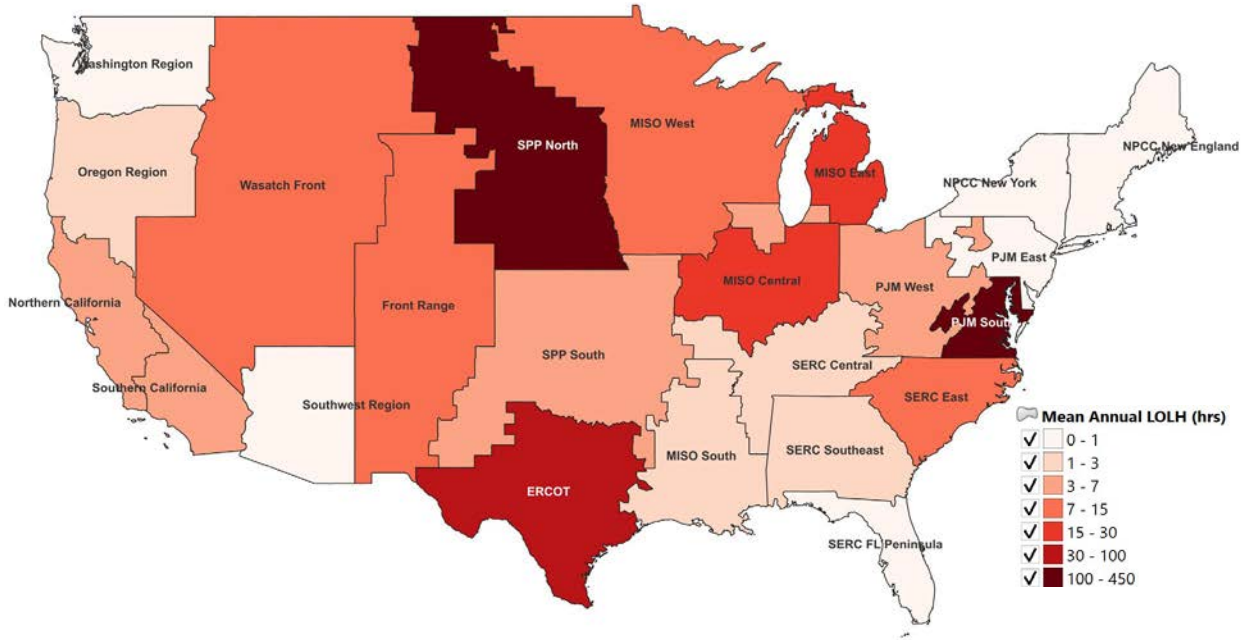


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

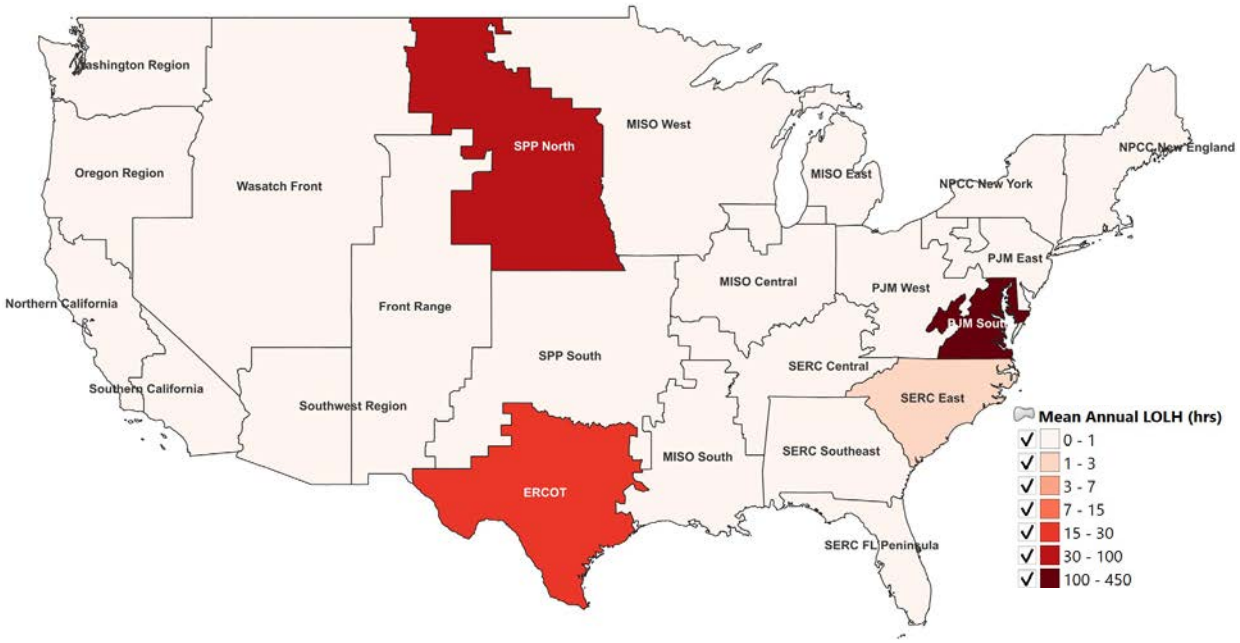


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,[12] and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

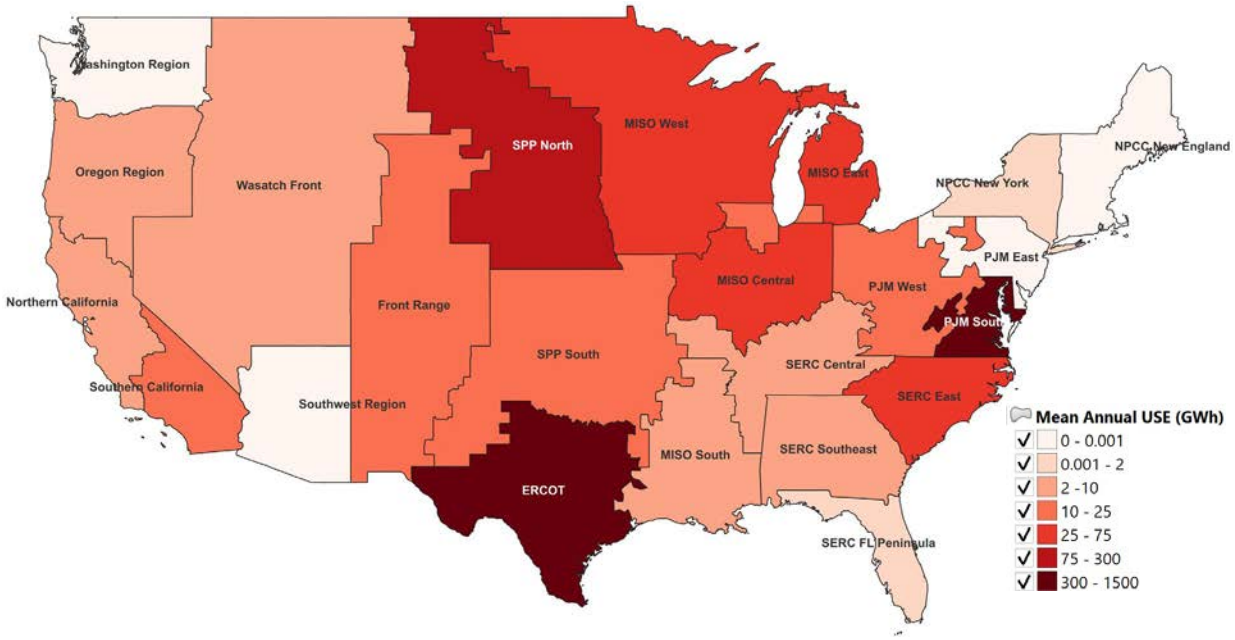


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures**: All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH)**: Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity**: Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy**: Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events**: Most regions experienced ≥3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways**: Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance**: Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures**:

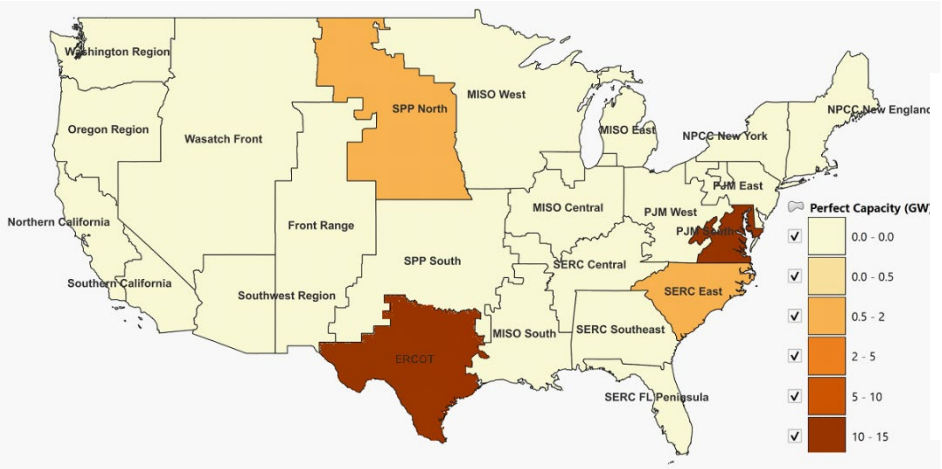
- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- **SERC-East**: Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as “perfect capacity,” this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.



	2024-Current System (MW)	2030-No Plant Closures (MW)
PJM	2400	10,500
SERC-E		500
SPP-N		1,500
ERCOT	1600	10500
Total	4000	23000

Perfect Capacity/Additions

Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS[13] model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)[14] including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,[15] it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS[16] base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

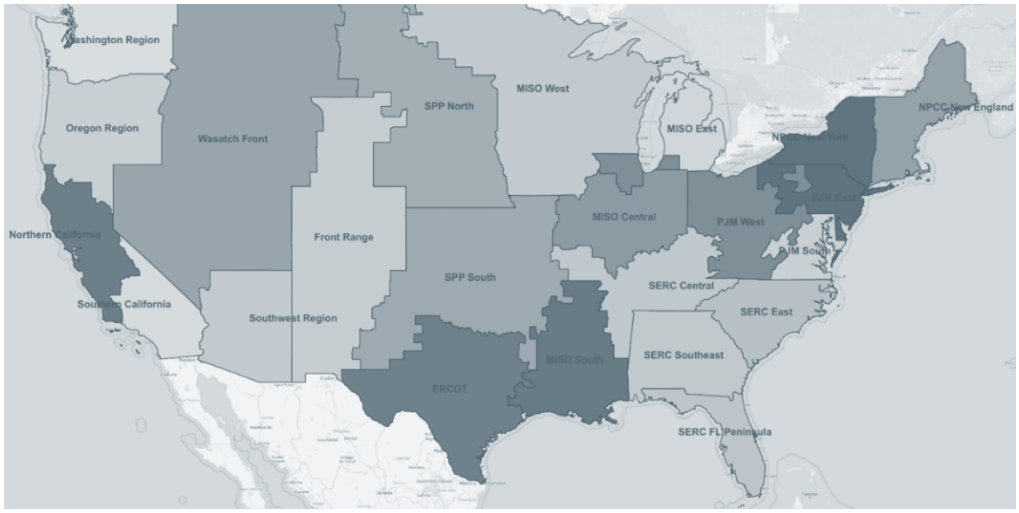


Figure 5. TPRs used in NERC ITCS

13. Energy Exemplar, "PLEXOS," https://www.energyexemplar.com/plexos.
14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.
15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").
16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.[17] Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.

- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.[18]

- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.

- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).

- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.

- **Transfer Capabilities and Imports/Exports -** Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.
18. See ITCS Final Report, Appendix G, for outage and derate methods.

  - Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.

  - To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See "Outputs" in the appendix for more details.

  - To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of $1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.

- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.
- **Demand Response –** Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for "Controllable and Dispatchable Demand Response – Available", or firm, controllable DR capacity.
- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:

  1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.[19]

  2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.

- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
    - *Normalized USE (percentage %):* The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.[20]
    - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
    - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
    - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
    - *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.

- *Max Consecutive LOLH (hours)*[21]: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

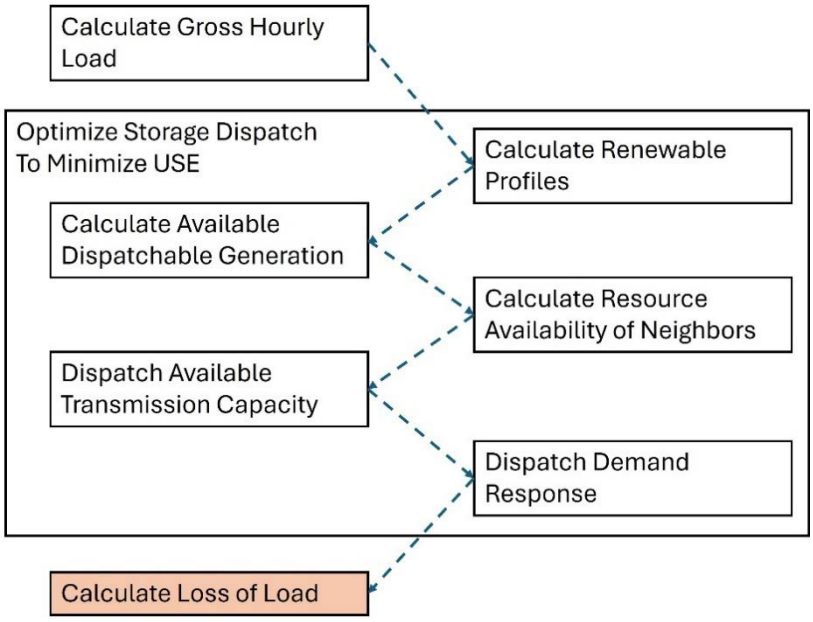


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.

- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.

- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.

- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 108 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

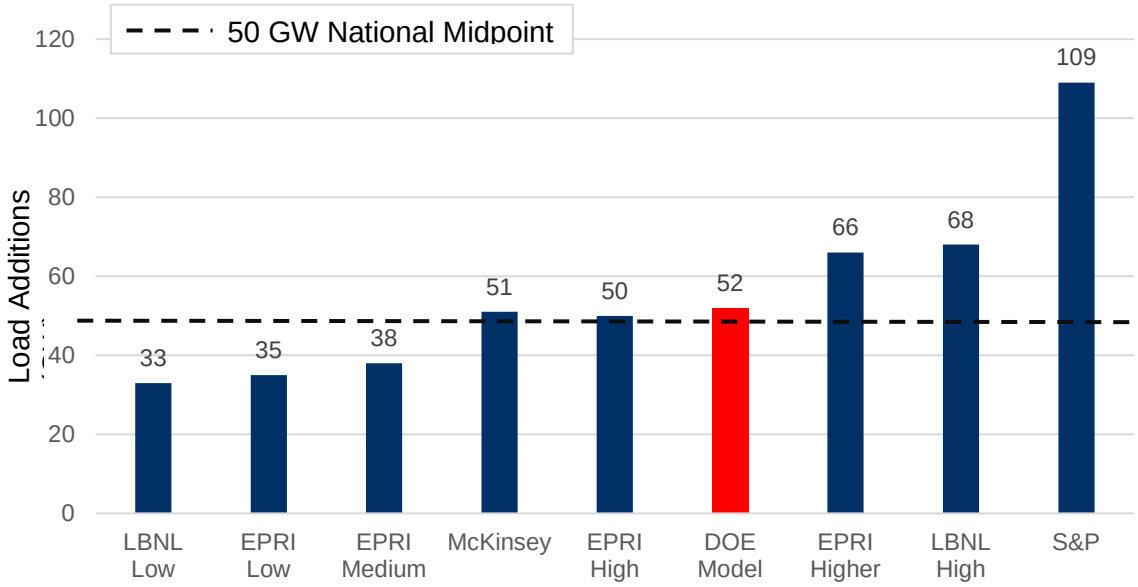


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 2 above displays a benchmark reflecting the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models.

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

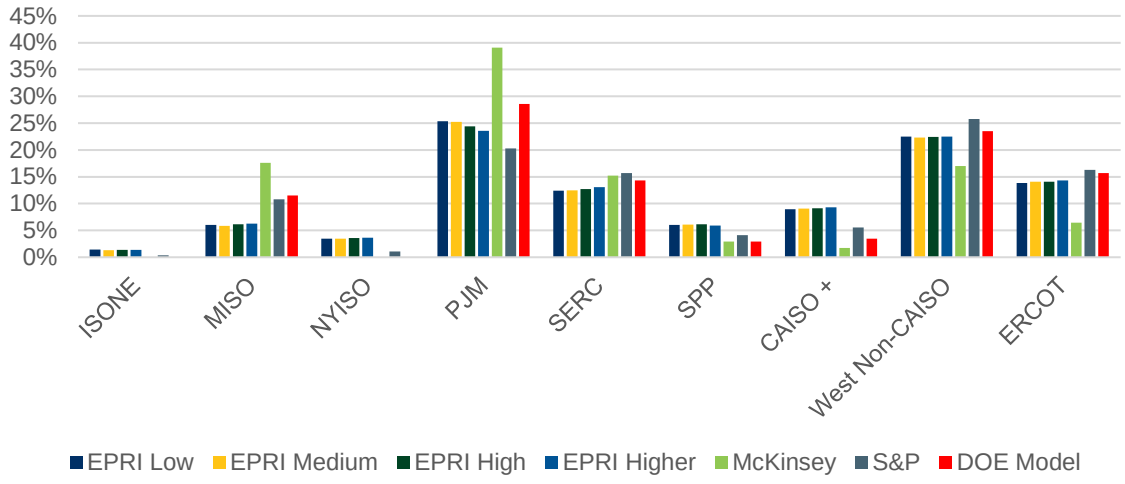


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

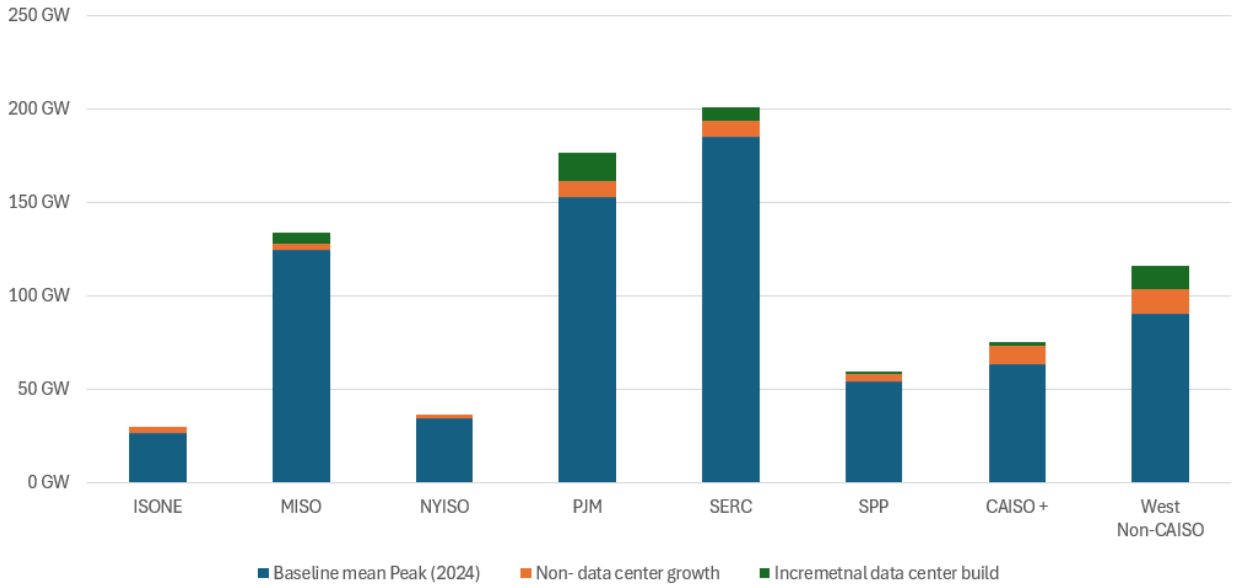


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.[22] Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%. [23]

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the "perfect capacity" to be as small as possible while reaching NUSE values below 0.002% in all regions.[24] As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term "expected unserved energy" because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, "Resource Adequacy Metrics and Criteria Roadmap," December 2024. https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf.

24. NERC, "Evolving Criteria for a Sustainable Power Grid," July 2024. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO[25]

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

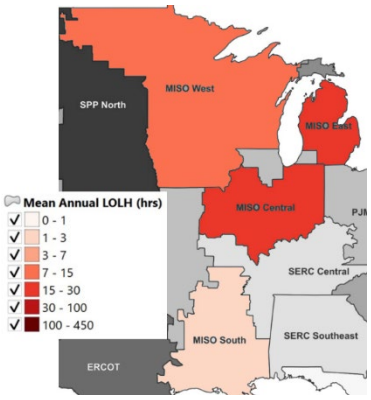


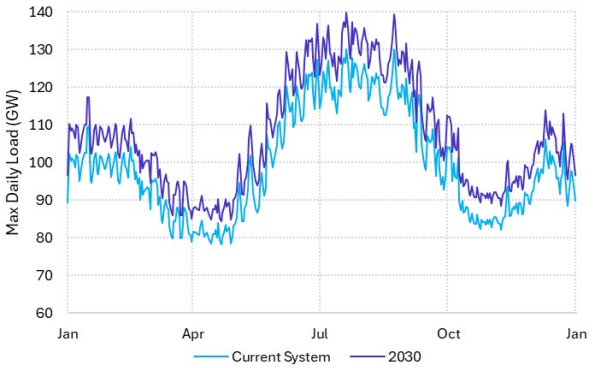
Table 2. Summary of MISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	**130,136**	**139,846**

Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.[26] In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	**207,319**	**196,049**	**228,393**

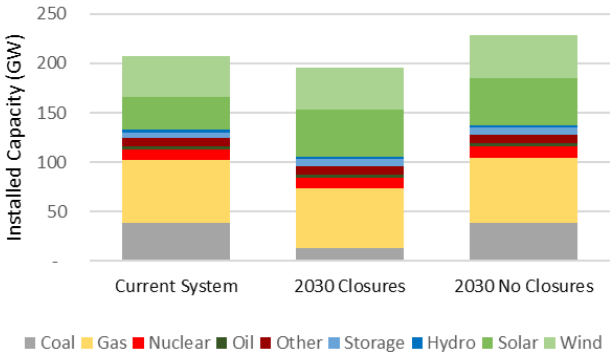


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**37,914**	**64,194**	**11,127**	**2,867**	**8,717**	**5,427**	**2,533**	**32,826**	**41,715**	**207,319**
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	**71,612**
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	**51,982**
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	**54,511**
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	**29,213**
Additions	**0**	**2,535**	**0**	**330**	**0**	**1,929**	**0**	**14,354**	**1,926**	**21,074**
MISO-W	0	537	0	172	0	374	0	3,552	1,358	**5,993**
MISO-C	0	407	0	57	0	934	0	5,103	339	**6,841**
MISO-S	0	1,226	0	68	0	9	0	3,868	27	**5,199**
MISO-E	0	364	0	34	0	611	0	1,831	201	**3,042**
Closures	**(24,913)**	**(6,597)**	**0**	**(324)**	**(140)**	**(16)**	**(83)**	**0**	**(272)**	**(32,345)**
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	**(10,152)**
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	**(11,088)**
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	**(6,954)**
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	**(4,150)**

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

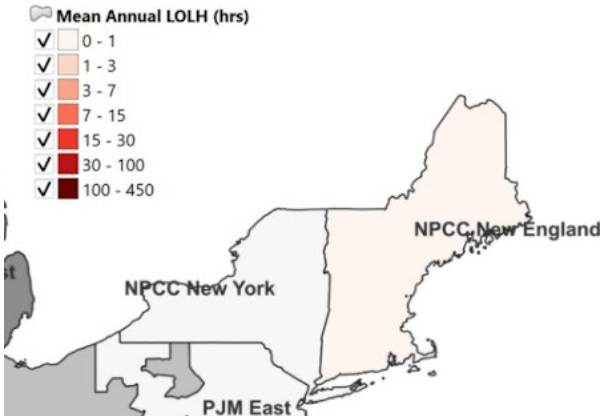
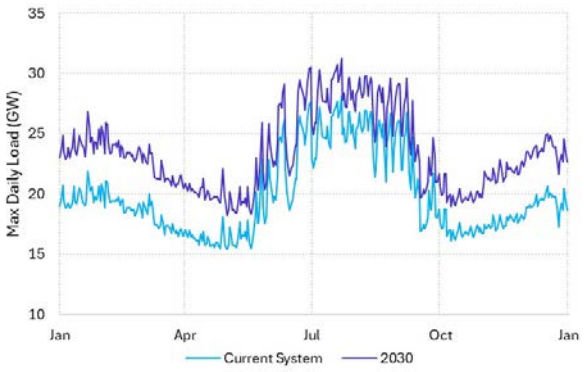


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	**28,128**	**31,261**

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	**39,979**	**42,845**	**45,534**

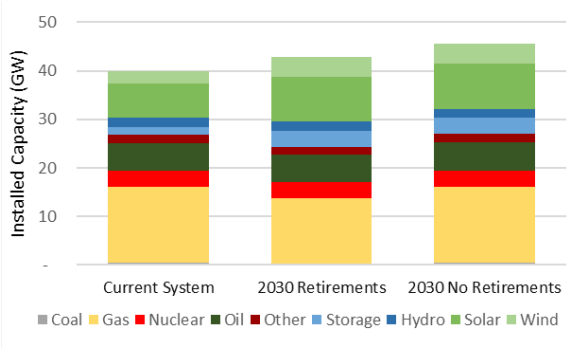


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**541**	**15,494**	**3,331**	**5,710**	**1,712**	**1,628**	**1,911**	**7,099**	**2,553**	**39,979**
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	**39,979**
Additions	**0**	**90**	**0**	**181**	**0**	**1,607**	**0**	**2,183**	**1,495**	**5,555**
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	**5,555**
Closures	**(534)**	**(1,875)**	**0**	**(203)**	**(77)**	**0**	**0**	**0**	**0**	**(2,690)**
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	**(2,690)**

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

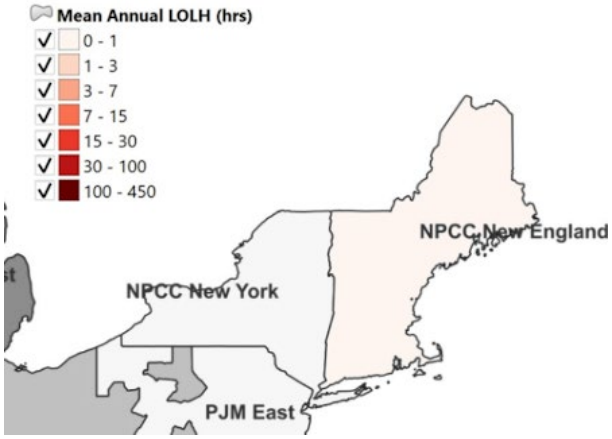
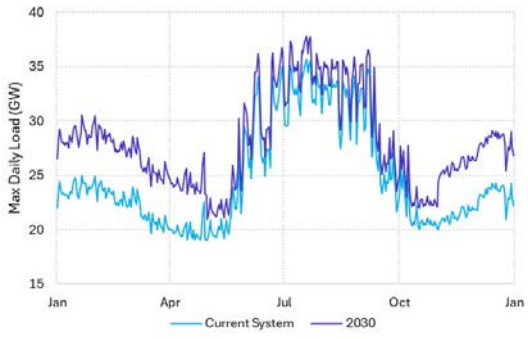


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
NYISO	35,669	37,844
Total	**35,669**	**37,844**

Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	**45,924**	**50,396**	**51,444**

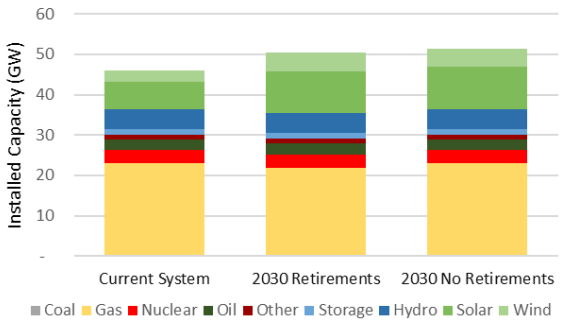


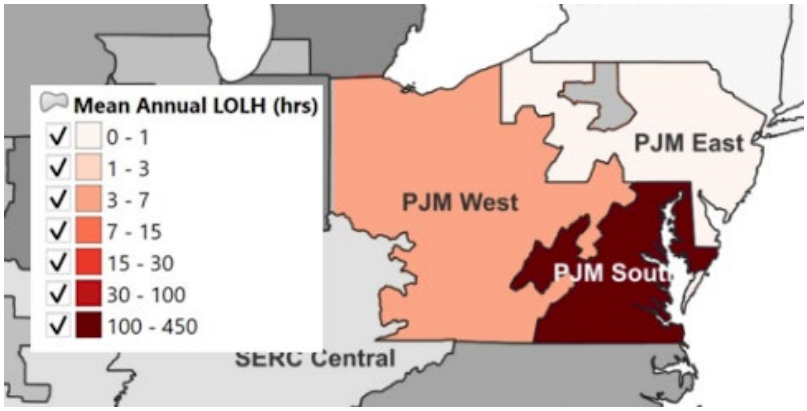
Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO's generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**0**	**22,937**	**3,330**	**2,631**	**1,194**	**1,460**	**4,915**	**6,749**	**2,706**	**45,924**
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	**45,924**
Additions	**0**	**0**	**0**	**15**	**0**	**0**	**0**	**3,604**	**1,902**	**5,521**
NYISO	0	0	0	15	0	0	0	3,604	1,902	**5,521**
Closures	**0**	**(1,030)**	**0**	**(19)**	**0**	**0**	**0**	**0**	**0**	**(1,049)**
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	**(1,049)**

2.4 PJM



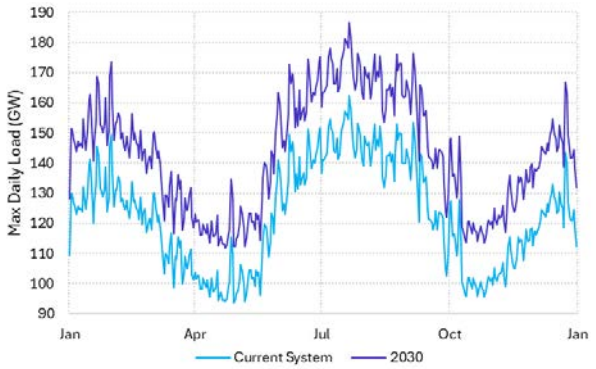
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

Table 8. Summary of PJM Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	**162,269**	**186,627**

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	**214,638**	**236,798**	**253,504**

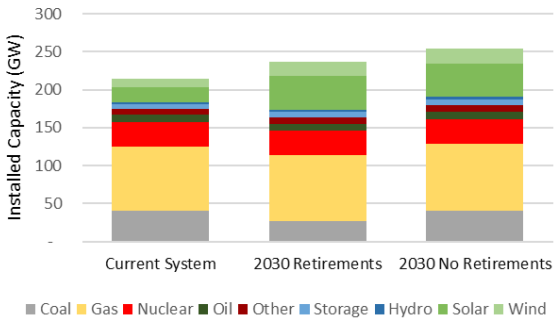


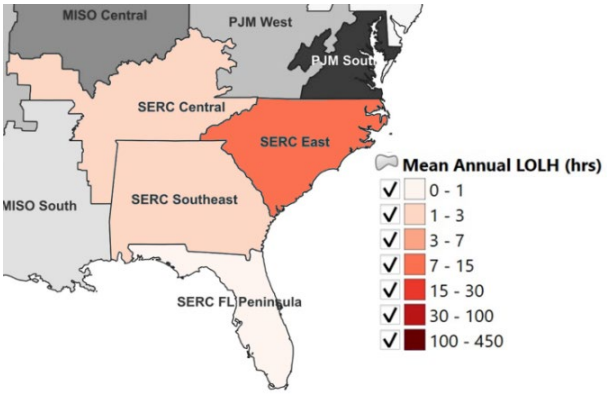
Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**39,915**	**84,381**	**32,535**	**9,875**	**8,248**	**5,400**	**3,071**	**19,495**	**11,718**	**214,638**
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	**114,467**
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	**39,951**
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	**60,221**
Additions	**0**	**4,499**	**0**	**32**	**317**	**1,938**	**0**	**24,991**	**7,089**	**38,866**
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	**21,343**
PJM-S	0	802	0	13	102	726	0	8,856	218	**10,717**
PJM-E	0	1,615	0	13	81	357	0	3,958	783	**6,806**
Closures	**(13,253)**	**(1,652)**	**0**	**(1,790)**	**(11)**	**0**	**0**	**0**	**0**	**(16,706)**
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	**(12,710)**
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	**(1,817)**
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	**(2,179)**

2.5 SERC



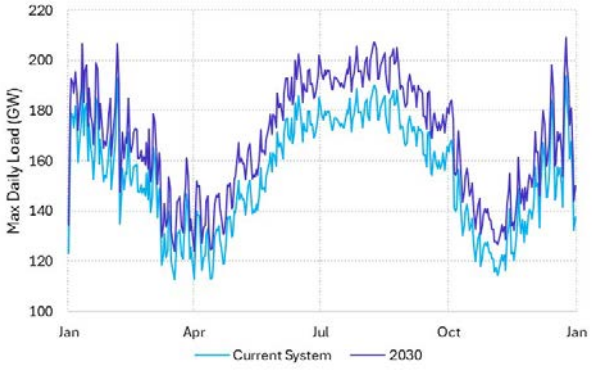
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

Table 10. Summary of SERC Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	**193,654**	**209,269**

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	**253,680**	**260,423**	**279,285**

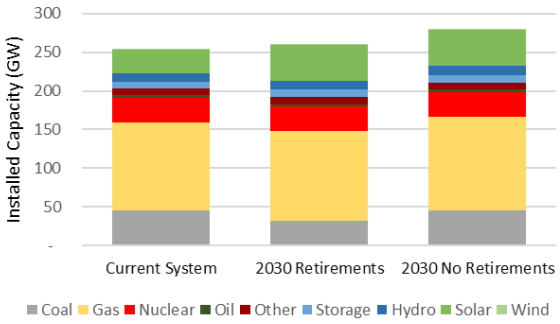


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**45,747**	**113,334**	**31,702**	**4,063**	**8,779**	**7,469**	**11,425**	**30,180**	**982**	**253,680**
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	**53,978**
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	**67,073**
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	**72,714**
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	**59,914**
Additions	**0**	**6,898**	**0**	**0**	**381**	**2,254**	**0**	**16,073**	**0**	**25,606**
SERC-C	0	4,831	0	0	0	80	0	771	0	**5,682**
SERC-SE	0	906	0	0	19	0	0	3,135	0	**4,059**
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	**13,459**
SERC-E	0	0	0	0	144	504	0	1,757	0	**2,405**
Closures	**(14,075)**	**(4,115)**	**0**	**(672)**	**0**	**0**	**0**	**0**	**0**	**(18,862)**
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	**(5,646)**
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	**(5,460)**
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	**(3,046)**
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	**(4,710)**

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

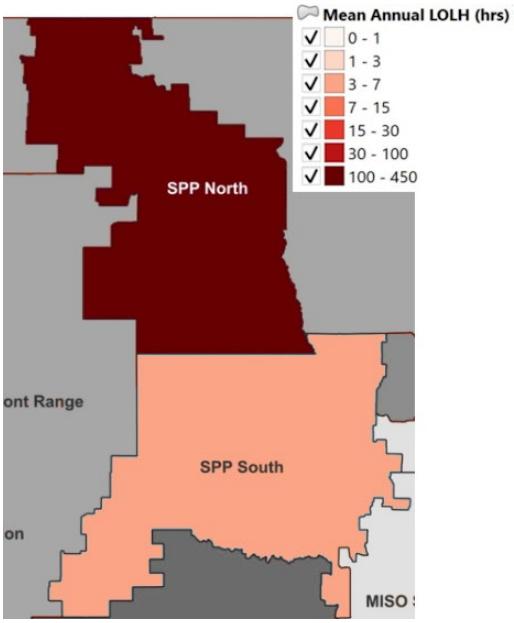
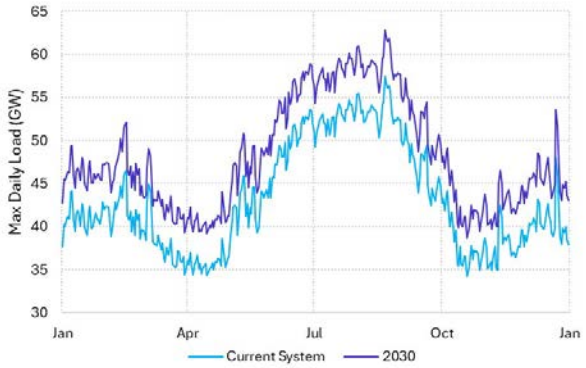


Table 12. Summary of SPP Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).



Subregion	2024	2030
SPP-N	12,668	14,676
SPP-S	44,898	48,337
Total	**57,449**	**62,891**

Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	**95,142**	**103,130**	**110,449**

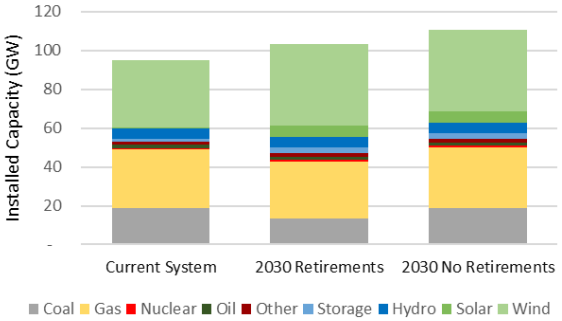


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**18,919**	**30,003**	**769**	**1,626**	**1,718**	**1,522**	**5,123**	**774**	**34,689**	**95,142**
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	**20,065**
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	**75,078**
Additions	**0**	**1,094**	**0**	**7**	**462**	**1,390**	**0**	**5,288**	**7,066**	**15,306**
SPP-N	0	126	0	2	114	11	0	633	1,434	**2,320**
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	**12,987**
Closures	**(5,530)**	**(1,732)**	**0**	**(56)**	**0**	**0**	**0**	**0**	**0**	**(7,318)**
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	**(1,705)**
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	**(5,613)**

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system's vulnerability to high load and low renewable output periods.

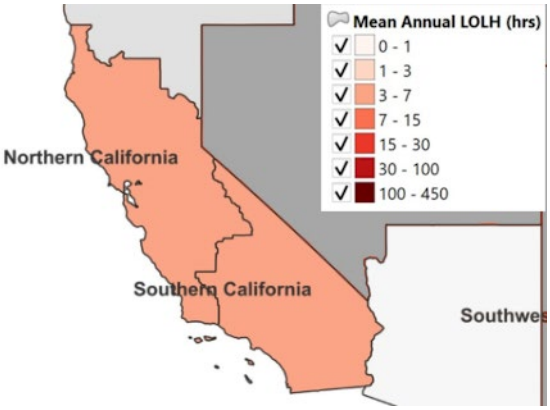
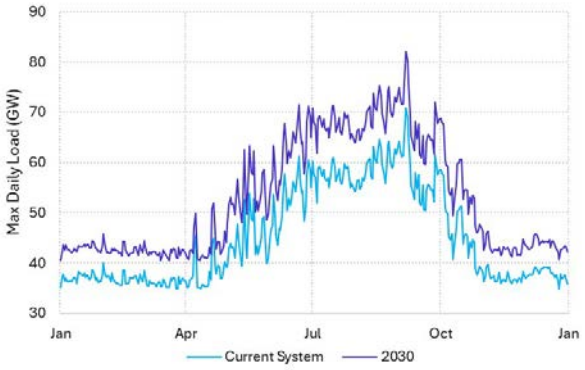


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+'s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	**70,815**	**82,146**

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	**116,925**	**122,938**	**130,809**

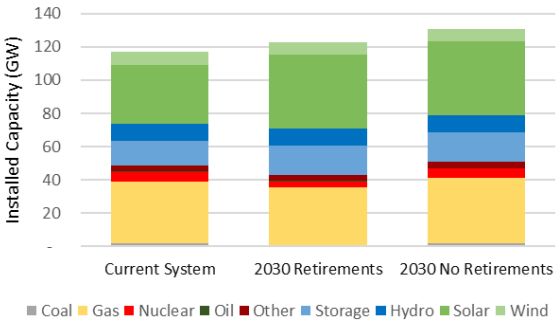


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**1,816**	**37,434**	**5,582**	**185**	**3,594**	**14,670**	**10,211**	**35,661**	**7,773**	**116,925**
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	**47,059**
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	**69,866**
Additions	**0**	**2,126**	**0**	**0**	**92**	**3,161**	**0**	**8,507**	**0**	**13,885**
CALI-N	0	735	0	0	44	757	0	3,906	0	**5,442**
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	**8,442**
Closures	**(1,800)**	**(3,771)**	**(2,300)**	**0**	**0**	**0**	**0**	**0**	**0**	**(7,871)**
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	**(3,604)**
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	**(4,267)**

2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

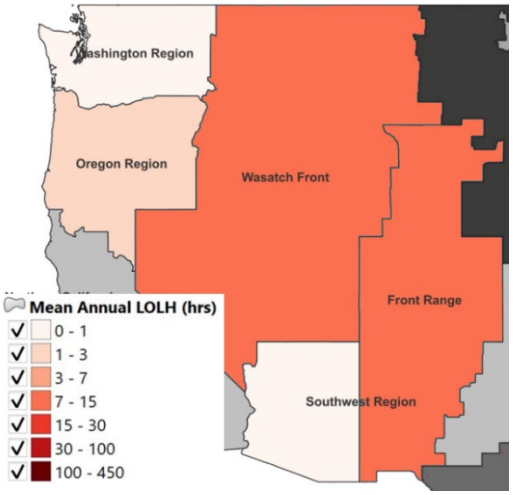
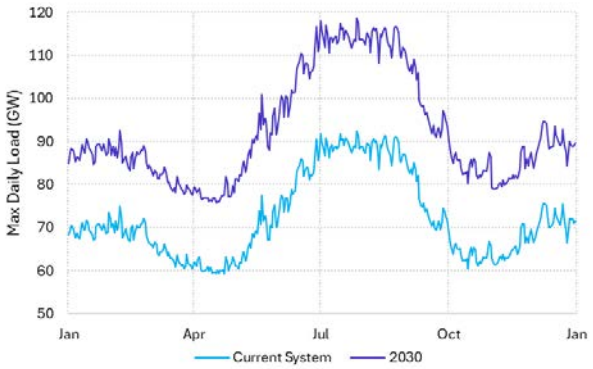


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	17.8	-	-
Normalized Unserved Energy (%)	-	0.0032	-	-
Unserved Load (MWh)	-	21,785	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	47	-	-
Normalized Unserved Load (%)	-	0.0098	-	-
Unserved Load (MWh)	-	66,248	-	-
Max Unserved Load (MW)	-	5,071	-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	**92,448**	**118,657**

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	**177,929**	**193,485**	**206,908**

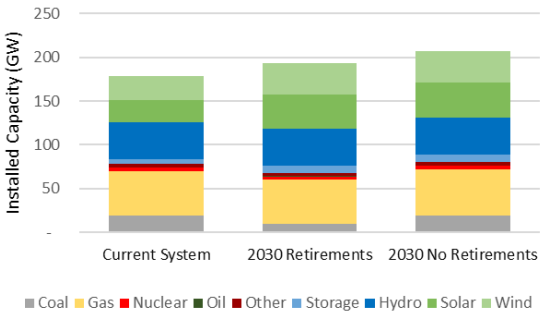


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**19,850**	**49,969**	**3,820**	**644**	**4,114**	**5,104**	**42,476**	**24,652**	**27,298**	**177,929**
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	**35,207**
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	**19,068**
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	**42,335**
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	**42,746**
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	**38,572**
Additions	**0**	**2,320**	**0**	**1**	**8**	**2,932**	**0**	**14,759**	**8,959**	**28,979**
WASHINGTON	0	246	0	0	0	109	0	1,059	952	**2,366**
OREGON	0	246	0	0	0	150	0	1,399	1,218	**3,013**
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	**6,823**
WASATCH	0	884	0	0	7	233	0	4,946	1,435	**7,505**
FRONT R	0	634	0	0	0	102	0	3,779	4,756	**9,271**
Closures	**(9,673)**	**(2,540)**	**0**	**(6)**	**(311)**	**(170)**	**(627)**	**0**	**(95)**	**(13,422)**
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	**(986)**
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	**(392)**
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	**(2,136)**
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	**(5,077)**
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	**(4,832)**

2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

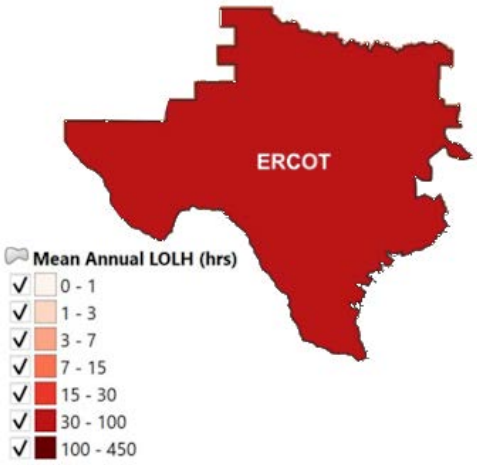
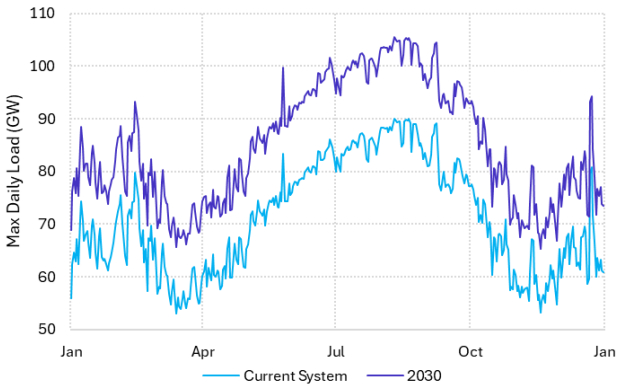


Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	**90,075**	**105,485**

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	**157,490**	**208,894**	**212,916**

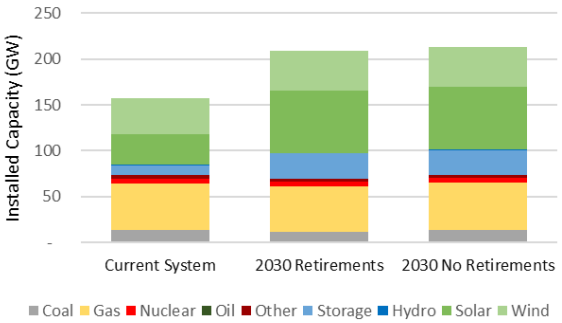


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**13,568**	**50,889**	**4,973**	**10**	**3,627**	**10,720**	**583**	**33,589**	**39,532**	**157,490**
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	**157,490**
Additions	**0**	**569**	**0**	**0**	**0**	**16,538**	**0**	**34,681**	**3,638**	**55,426**
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	**55,426**
Closures	**(2,000)**	**(2,022)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(4,022)**
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	**(4,022)**

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.[27] This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs[28], the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities[29] and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

27. NERC, “Interregional Transfer Capability Study (ITCS).” https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, “2024 Long-Term Reliability Assessment,” December, 2024, 24. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

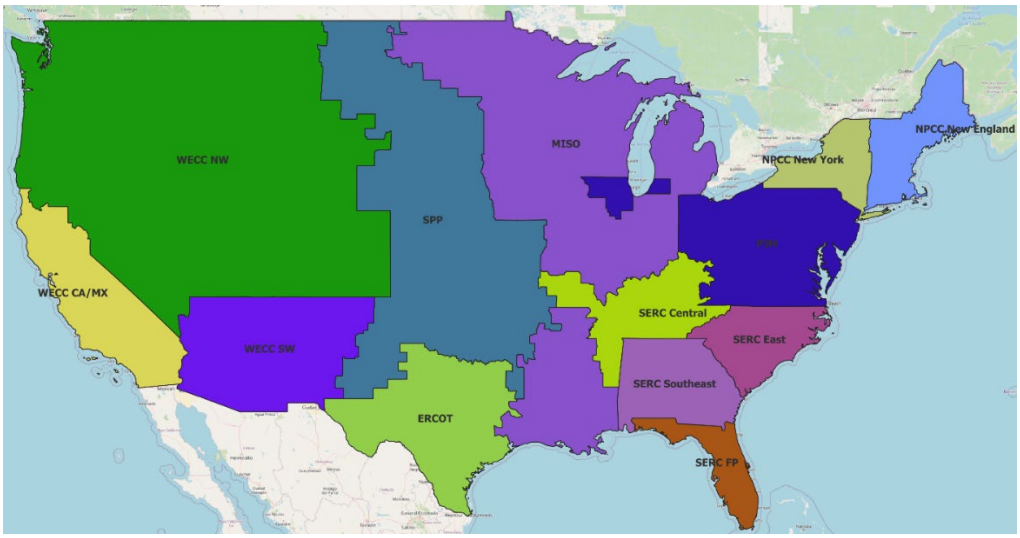


Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.[30] Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \quad \textit{(Equation.1)}$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R. The denominator is the total capacity of that fuel type across all ITCS regions mapped to R.

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, "Regional Energy Development System," https://www.nrel.gov/analysis/reeds/.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Exsting + Tier 1			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**330,342**	**82,793**	**26,771**	**3,624**	**-**	**991**	**19,607**	**3,298**	**28,980**	**72,757**	**94,364**	**25,753**	**24,367**	**856,682**
	ISONE	**Total**	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO	**Total**	**37,914**	**64,194**	**11,127**	**2,867**	**613**	**-**	**329**	**4,396**	**1,031**	**2,533**	**29,777**	**41,715**	**7,775**	**3,049**	**207,319**
		MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
		MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
		MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
		MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO	**Total**	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM	**Total**	**39,915**	**84,381**	**32,535**	**9,875**	**851**	**-**	**-**	**5,062**	**338**	**3,071**	**10,892**	**11,718**	**7,397**	**8,603**	**214,638**
		PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
		PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
		PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC	**Total**	**45,747**	**113,334**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**768**	**11,425**	**26,959**	**982**	**7,707**	**3,221**	**253,680**
		SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
		SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
		SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP	**Total**	**18,919**	**30,003**	**769**	**1,626**	**20**	**-**	**345**	**477**	**1,044**	**5,123**	**703**	**34,689**	**1,353**	**71**	**95,142**
		SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
		SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	**Total**		**13,568**	**50,889**	**4,973**	**10**	**163**	**-**	**-**	**-**	**10,720**	**583**	**31,058**	**39,532**	**3,464**	**2,531**	**157,490**
	ERCOT	**Total**	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	**Total**		**21,666**	**87,403**	**9,403**	**829**	**1,565**	**4,093**	**106**	**4,536**	**15,238**	**52,687**	**44,042**	**35,071**	**1,944**	**16,271**	**294,854**
	CAISO+	**Total**	**1,816**	**37,434**	**5,582**	**185**	**726**	**2,004**	**35**	**3,514**	**11,156**	**10,211**	**25,614**	**7,773**	**829**	**10,047**	**116,925**
		CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
		CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC	**Total**	**19,850**	**49,969**	**3,820**	**644**	**839**	**2,089**	**71**	**1,022**	**4,082**	**42,476**	**18,428**	**27,298**	**1,115**	**6,224**	**177,929**
		WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
		OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
		SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
		WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
		FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
		Total	**178,268**	**468,635**	**97,169**	**27,610**	**5,353**	**4,093**	**1,096**	**24,144**	**29,256**	**82,249**	**147,856**	**168,966**	**31,161**	**43,169**	**1,309,026**

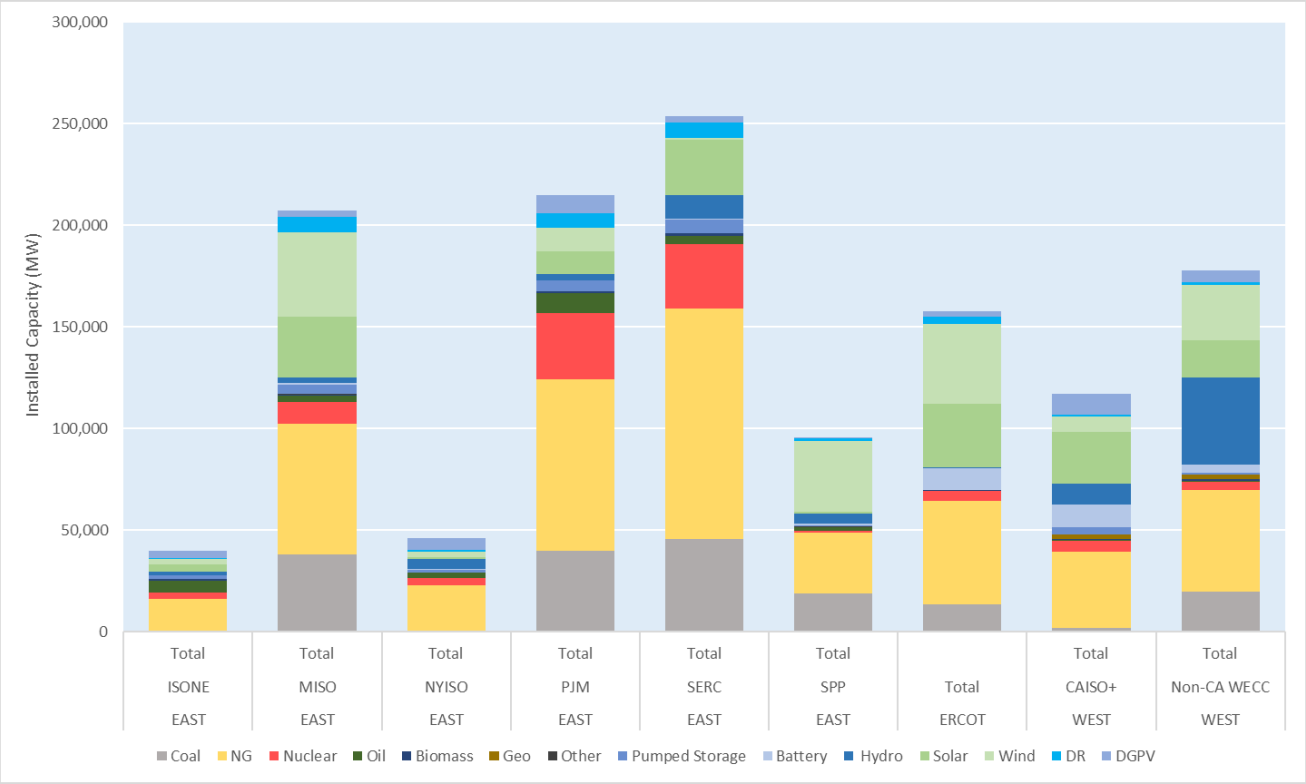


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

(i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

(i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

(ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

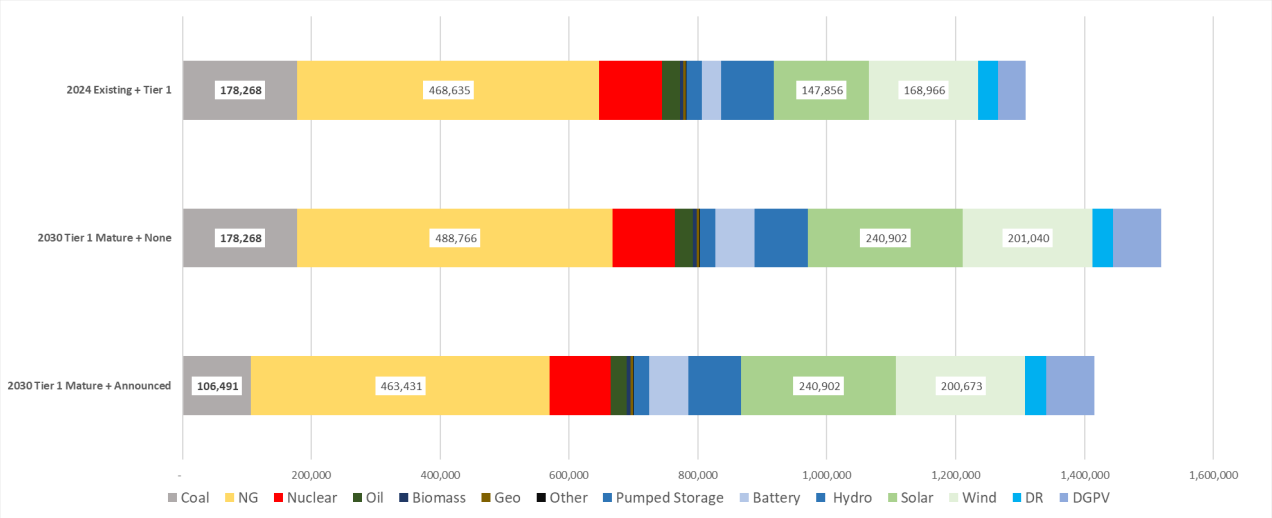


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**84,730**	**328,457**	**82,793**	**24,272**	**3,473**	**-**	**991**	**19,591**	**12,415**	**28,897**	**126,849**	**113,568**	**26,837**	**36,768**	**889,641**
	ISONE	**Total**	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO	**Total**	**13,001**	**60,132**	**11,127**	**2,873**	**473**	**-**	**329**	**4,380**	**2,960**	**2,450**	**44,132**	**43,369**	**7,775**	**3,049**	**196,049**
		MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
		MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
		MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
		MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO	**Total**	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM	**Total**	**26,662**	**87,228**	**32,535**	**8,117**	**917**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**236,798**
		PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
		PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
		PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC	**Total**	**31,672**	**116,117**	**31,702**	**3,391**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**260,423**
		SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
		SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
		SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
		SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP	**Total**	**13,389**	**29,365**	**769**	**1,576**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**103,130**
		SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
		SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	**Total**		**11,568**	**49,436**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**208,894**
	ERCOT	**Total**	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	**Total**		**10,193**	**85,538**	**7,103**	**823**	**1,427**	**3,983**	**106**	**4,366**	**21,330**	**52,060**	**51,648**	**43,935**	**1,981**	**31,931**	**316,424**
	CAISO+	**Total**	**16**	**35,789**	**3,282**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**122,938**
		CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
		CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC	**Total**	**10,177**	**49,749**	**3,820**	**639**	**701**	**1,924**	**71**	**852**	**7,014**	**41,849**	**24,536**	**36,162**	**1,115**	**14,876**	**193,485**
		WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
		OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
		SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
		WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
		FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
		Total	**106,491**	**463,431**	**94,869**	**25,106**	**5,063**	**3,983**	**1,096**	**23,958**	**61,003**	**81,539**	**240,902**	**200,673**	**32,282**	**74,563**	**1,414,959**

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**345,459**	**82,793**	**27,336**	**3,701**	**-**	**991**	**19,607**	**12,415**	**28,980**	**126,849**	**113,840**	**26,837**	**36,768**	**968,610**
	ISONE	**Total**	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	**Total**	**37,914**	**66,729**	**11,127**	**3,197**	**613**	**-**	**329**	**4,396**	**2,960**	**2,533**	**44,132**	**43,641**	**7,775**	**3,049**	**228,393**
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	**Total**	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	**Total**	**39,915**	**88,880**	**32,535**	**9,907**	**928**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**253,504**
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	**Total**	**45,747**	**120,232**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**279,285**
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	**Total**	**18,919**	**31,098**	**769**	**1,632**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**110,449**
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	**Total**		**13,568**	**51,458**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**212,916**
	ERCOT	**Total**	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	**Total**		**21,666**	**91,849**	**9,403**	**829**	**1,565**	**4,156**	**106**	**4,536**	**21,330**	**52,687**	**51,648**	**44,030**	**1,981**	**31,931**	**337,717**
	CAISO+	**Total**	**1,816**	**39,560**	**5,582**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**130,809**
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	**Total**	**19,850**	**52,289**	**3,820**	**645**	**839**	**2,097**	**71**	**1,022**	**7,014**	**42,476**	**24,536**	**36,257**	**1,115**	**14,876**	**206,908**
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
		Total	**178,268**	**488,766**	**97,169**	**28,175**	**5,429**	**4,156**	**1,096**	**24,144**	**61,003**	**82,249**	**240,902**	**201,040**	**32,282**	**74,563**	**1,519,243**

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.[1–17]

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a "learning rate" scales each tree's contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

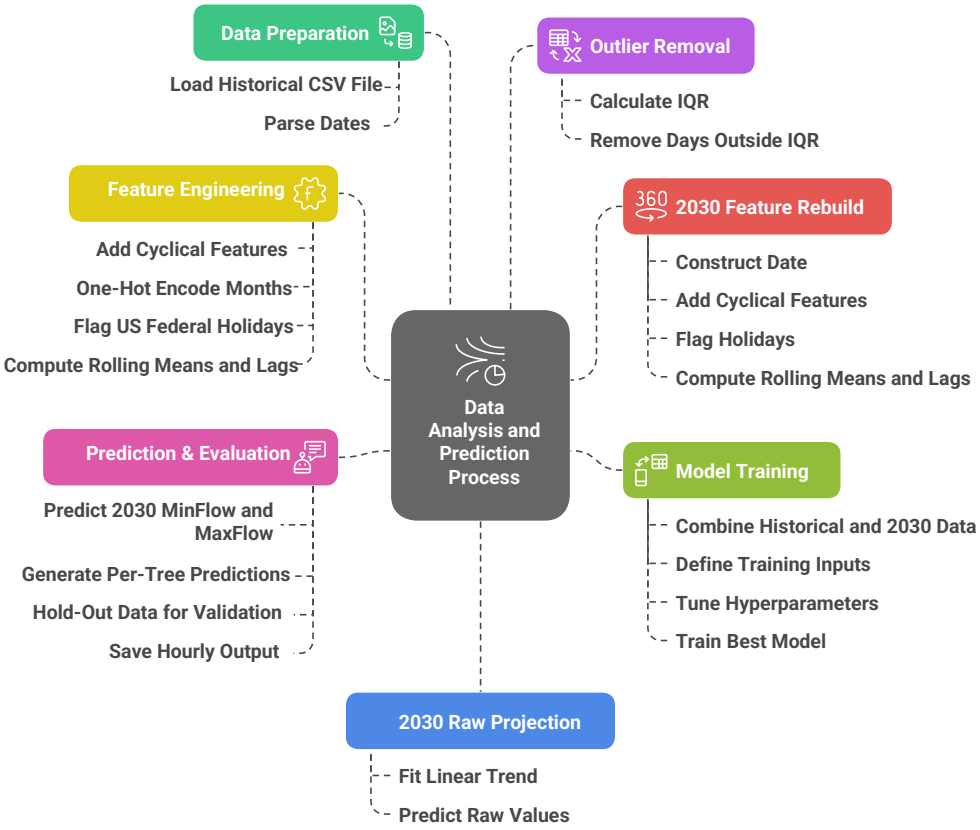


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year's MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

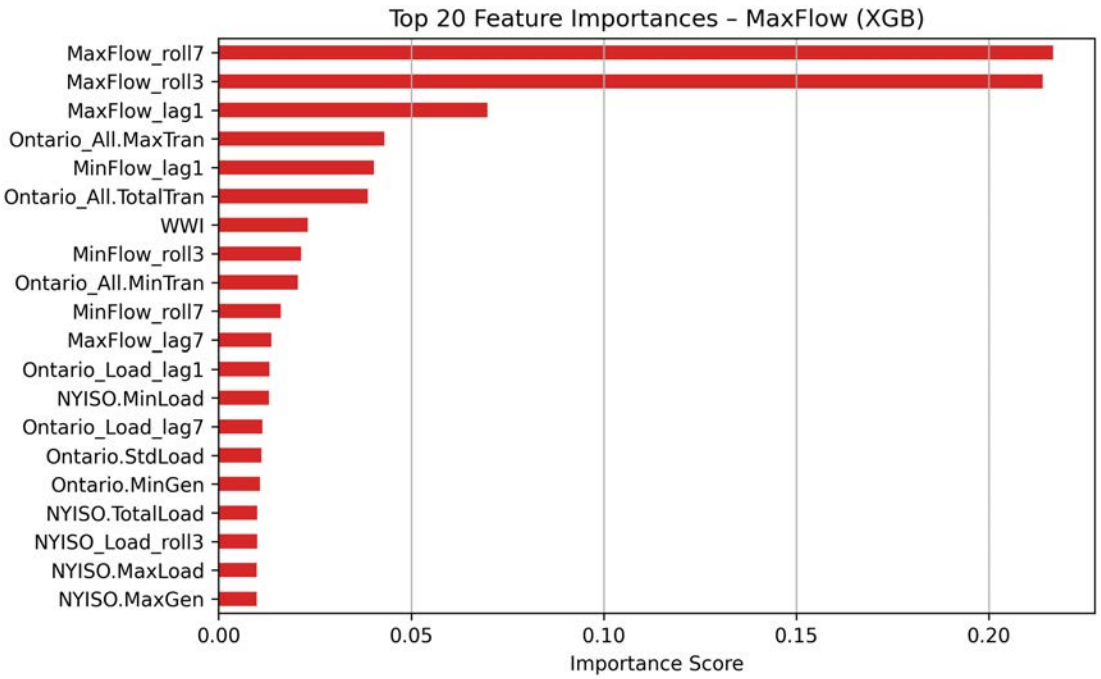


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

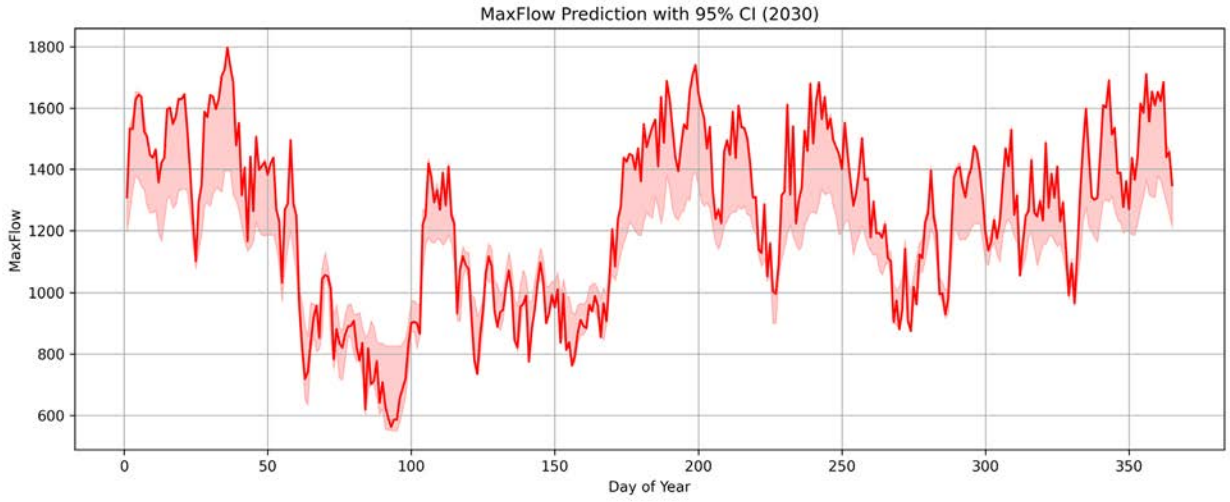


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model's reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

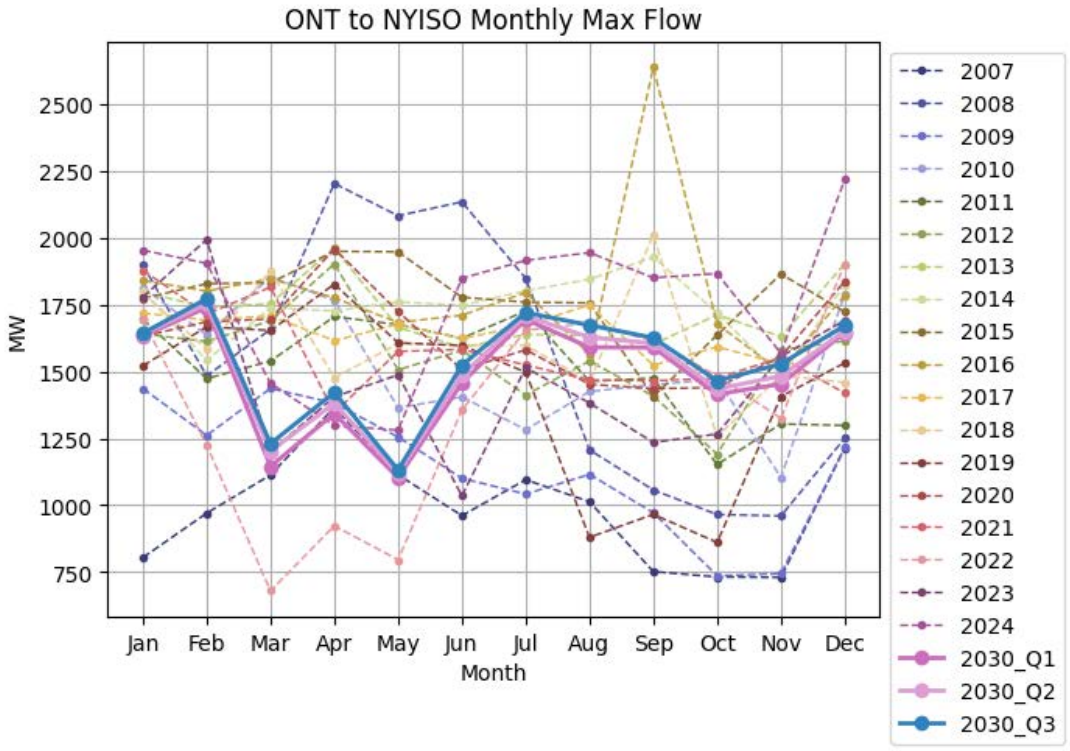


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ±150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load,

generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

(iii) Pacific Northwest to British Columbia

(iv) Alberta to Montana

(v) Manitoba to MISO West

(vi) Ontario to MISO West

(vii) Ontario to MISO East

(viii) Ontario to New York

(ix) Hydro-Quebec to New York

(x) Hydro-Quebec to New England

(xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

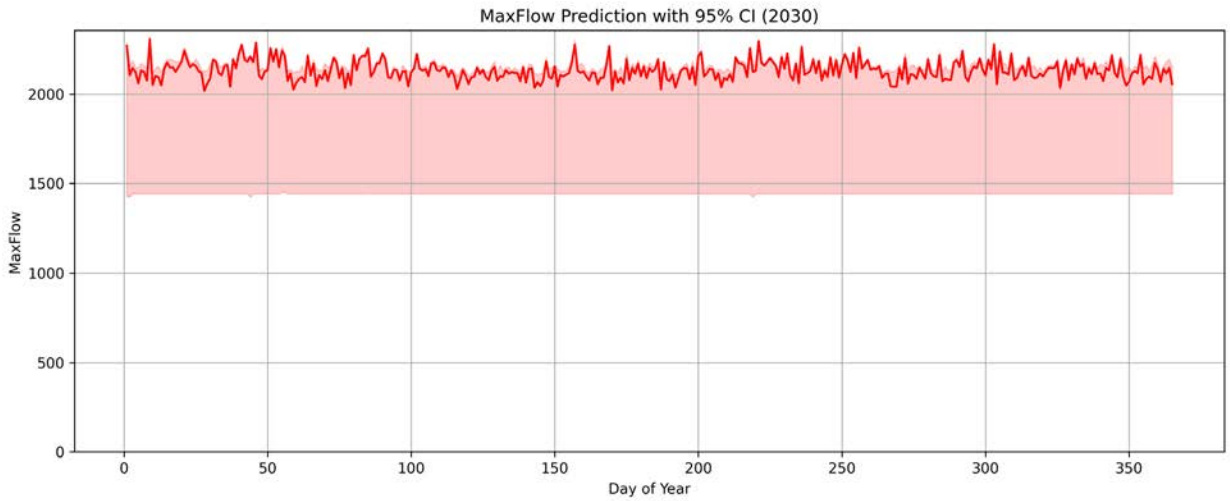


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

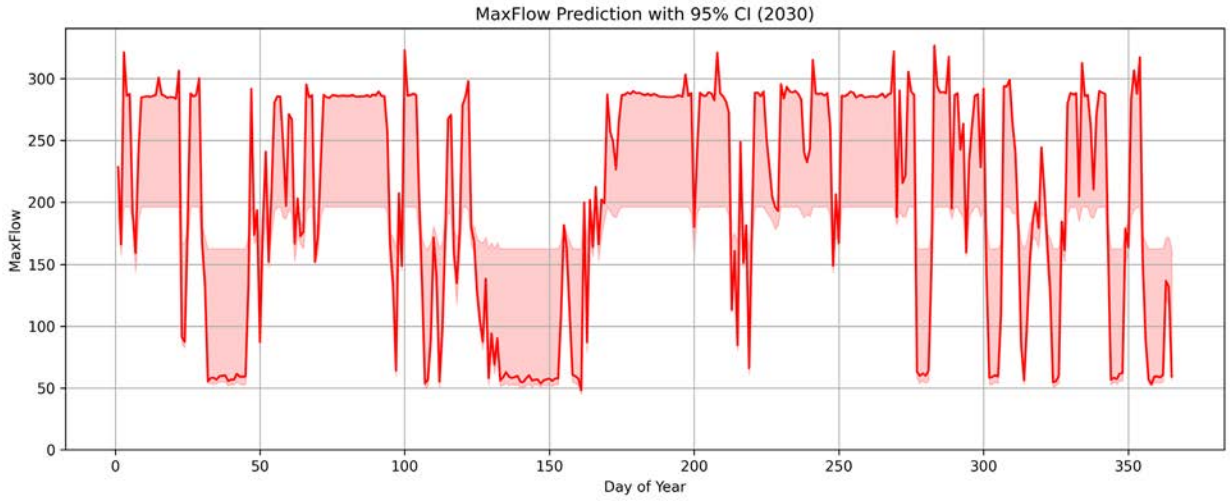


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

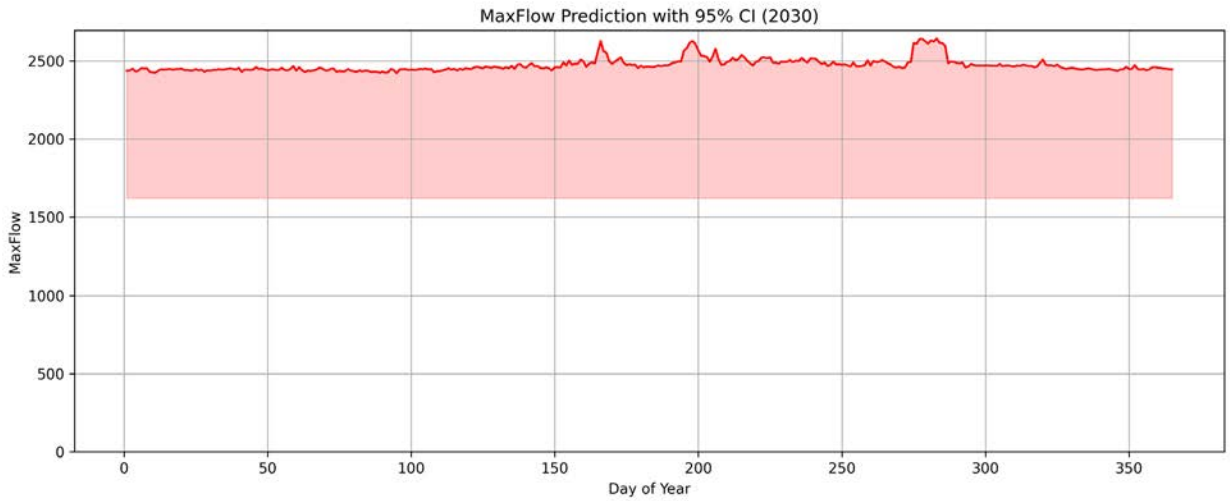


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

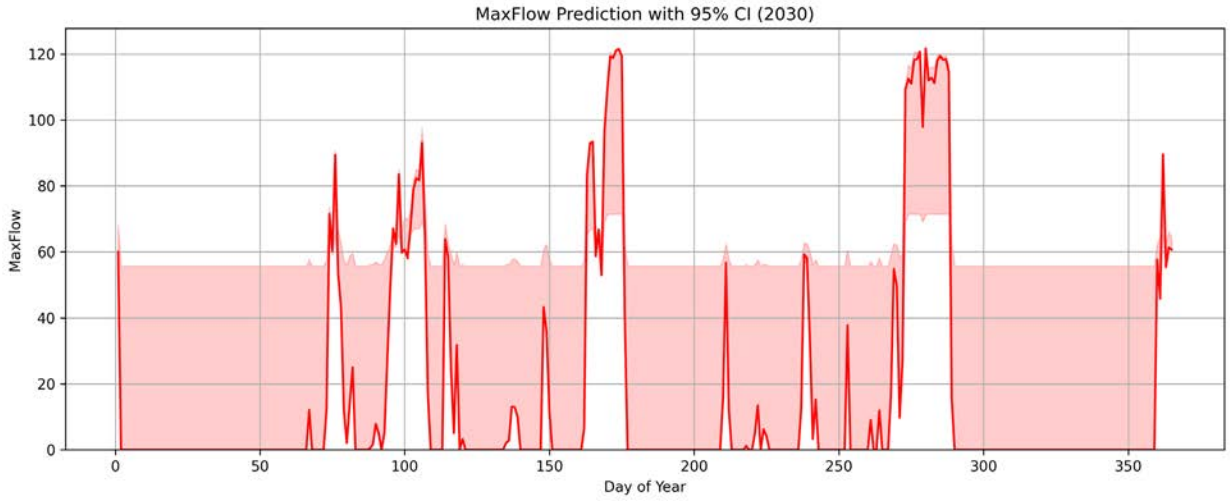


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

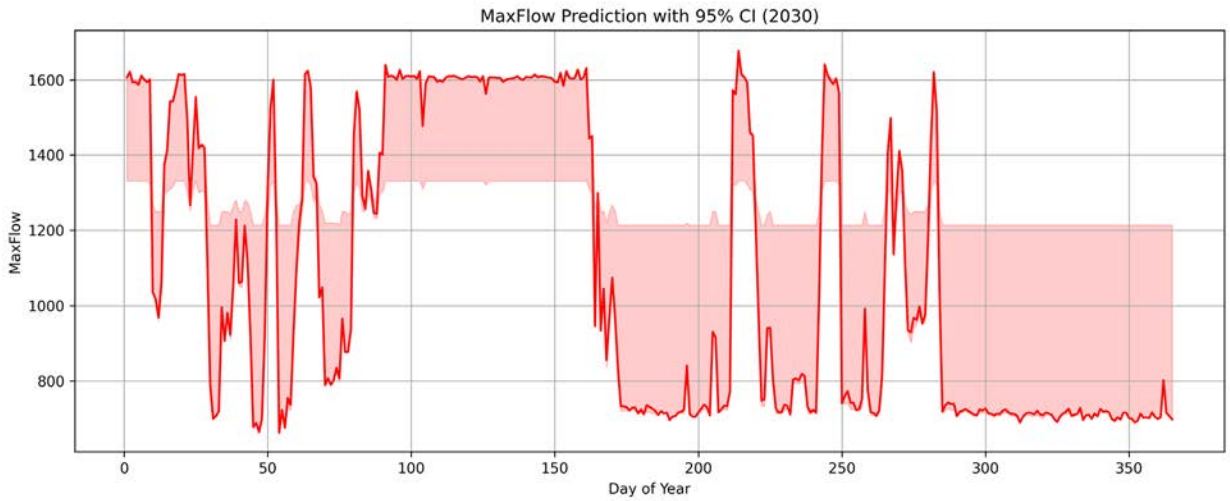


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

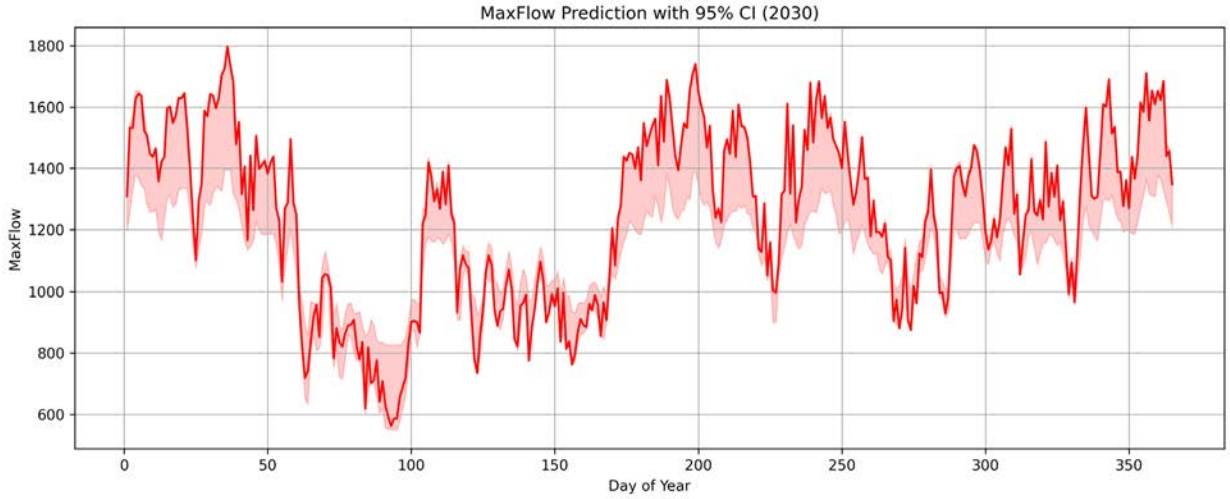


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

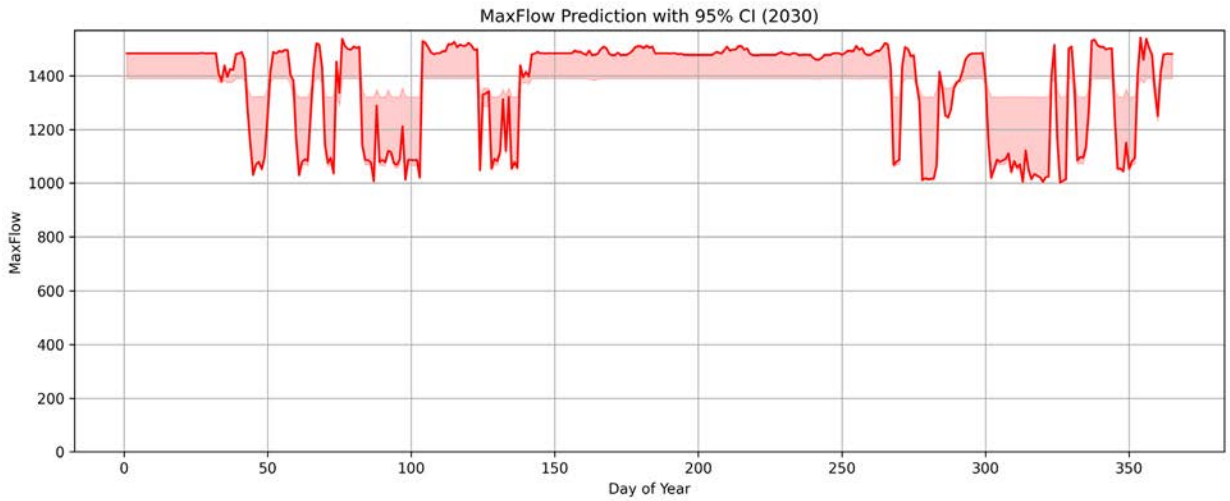


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

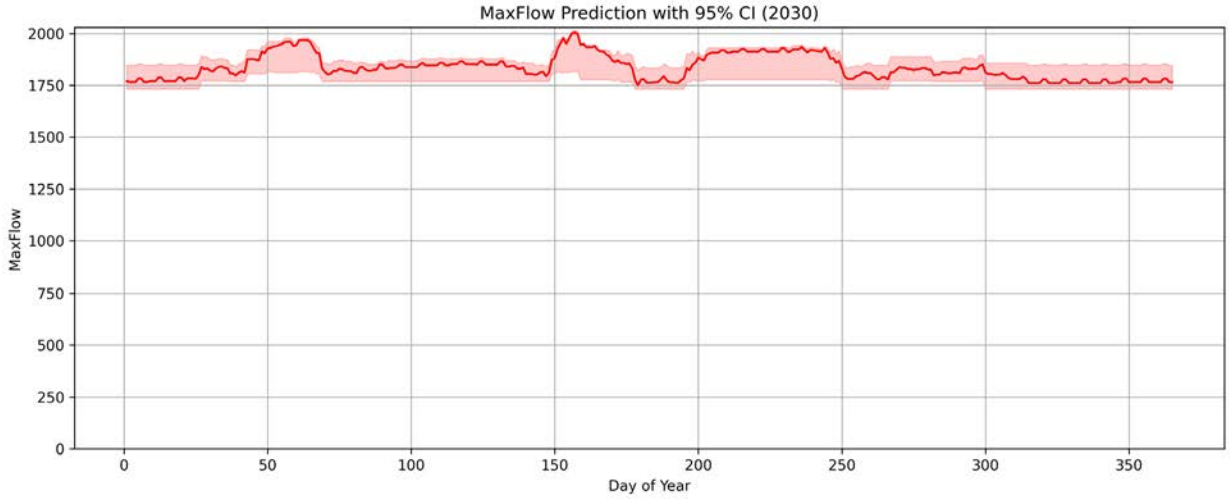


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

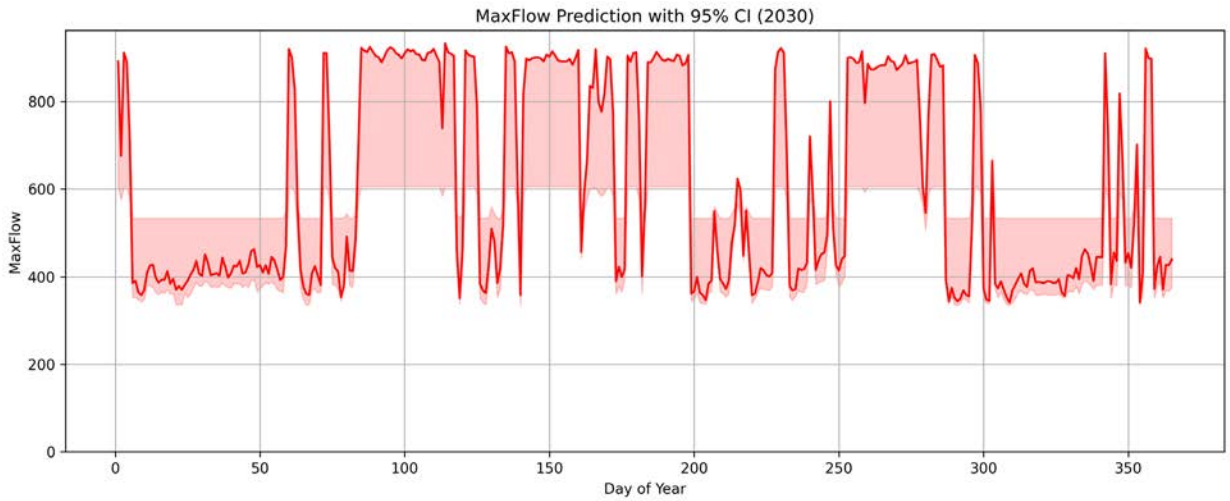


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

References

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EO 14262

Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents 15521

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose.* The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. *Policy.* It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. *Addressing Energy Reliability and Security with Emergency Authority.* (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

(i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;

(ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and

(iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

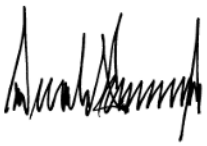
Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025–06381
Filed 4–11–25; 8:45 am]
Billing code 3395–F4–P

Available at (accessed on 5/27/2025):
https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid

U.S. DEPARTMENT of ENERGY

For more information, visit:
energy.gov/topics/reliability

DOE/Publication Number • July, 7 2025

Attachment S

State AG Request For Rehearing of DOE Report
Aug 6 2025

BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

In re: Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, July 2025	Submitted via e-mail to: AskCR@hq.doe.gov August 6, 2025

Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York

The Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York ("the States") make this filing to raise our concerns with the Department of Energy's ("Department" or "DOE") report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, published July 7, 2025 ("Report"),[1] and request rehearing of the same.

Given that DOE has not yet applied the report to issue future emergency orders, the States do not concede that the Federal Power Act requires the States to request rehearing at this time.[2] Still, the States acknowledge that President Trump instructed DOE to use the methodology in this report as part of a "protocol" to issue orders pursuant to Section 202(c) of the Federal Power Act preventing the retirement of power plants identified as critical to reliability in DOE's report.[3] DOE has indicated that it intends to comply with that mandate and use this Report to "guide reliability interventions" and issue Section 202(c) emergency orders.[4] The States reserve all rights to present these objections, or any other objection or legal challenge to the Report or DOE's reliance on this report going forward. However, out of an abundance of caution and to preserve their arguments, the States also formally request rehearing of the methodology,

[1] Available at https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29_0.pdf [https://perma.cc/J2XU-2RRJ].
[2] *See* 16 U.S.C. § 825*l*.
[3] *See* Exec. Order No. 14,262, 90 Fed. Reg. 15,521 (Apr. 14, 2025).
[4] *See* U.S. DEP'T OF ENERGY, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [https://perma.cc/YLX7-8G7T] (explaining that DOE's methodology will be used, pursuant to the executive order, "prevent [] generation resources from leaving the bulk-power system"); Press Release, U.S. Dep't of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security [https://perma.cc/8TEJ-AGH6]. (stating that its "methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act"); Report at *vi* (explaining that DOE's standard will be used to "guide reliability interventions"), 1 (emphasizing the need for DOE's "decisive intervention" in energy markets), 10 (analyzing ERCOT because "FPA Section 202(c) allows DOE to issue emergency orders to ERCOT").

standards, and protocol identified in this Report under Section 313*l* of the Federal Power Act, 16 U.S.C. § 825*l*.

This filing details the ways in which the Report is arbitrary and why it would be unlawful to rely on it to justify future Section 202(c) orders. The States also request DOE review the Report independently before it is used in any capacity in order to address the serious errors in the analysis highlighted here.

I. Motion to Intervene

The Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York move to intervene in this proceeding pursuant to Section 313*l* of the Federal Power Act, 16 U.S.C. § 825*l*, and request that the Department of Energy grant rehearing of its July 7, 2025 report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*.

Executive Order 14262 and DOE's own statements alongside the Report's publication indicate that it will be used to "guide reliability interventions" and justify issuance of emergency orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c). The Report is deeply flawed and, if DOE is taken at its word, it will inflict significant harm on our states.

Many of the retiring resources targeted by this report are located in our states. In Washington, for example, the Transalta Centralia coal-fired power plant is scheduled to retire in December 2025. In Colorado, the Craig and Comanche coal-fired power plants are scheduled to retire by the end of the year as well and the state's remaining coal fired power plants are scheduled to retire by 2031. These retirements have been thoroughly vetted by state and regional authorities and approved only following an extensive examination of cost considerations and reliability impacts.

And even when a source is not located directly in one of our states, the ratepayer impacts of overriding a planned retirement based on the DOE Report will often be felt by our residents. That is because many of these resources operate within regional transmission systems that spread costs across all, or a portion of, their footprint. In MISO, for example, ratepayers across the ISO's north and central regions are being asked to foot the bill for the continued operation of the J.H. Campbell coal-fired power plant in Michigan pursuant to a Section 202(c) order issued by DOE in May. In just five weeks, complying with that Order has cost the plant's owner $29 million.[5] The order is expected to cost consumers close to $100 million if it expires on August 21 and is not renewed.[6]

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[5] *See* CMS Energy Corp., Quarterly Report (Form 10-Q) (Jul. 31, 2025), https://www.sec.gov/ix?doc=/Archives/edgar/data/0000201533/000081115625000071/cms-20250630.htm.

[6] Brian Dabbs, *Coal Plant Ordered to Stay Open Cost $29M to Run in 5 Weeks*, POLITICO ENERGYWIRE (Aug. 1, 2025), https://subscriber.politicopro.com/article/eenews/2025/08/01/coal-plant-ordered-to-stay-open-cost-29m-to-run-in-5-weeks-00487542.

Our states are also harmed when Section 202(c) is used to keep polluting facilities from retiring in upwind locations. Fossil-fuel power plants are large sources of ozone-forming pollution and toxic emissions that contribute to nonattainment of air quality standards in downwind states like Connecticut, New York, and Maryland. Planned retirements have the benefit of reducing this pollution and overriding those state and regional determinations based on the DOE Report will further the harm that downwind states face from upwind sources.

Moreover, the report unlawfully intrudes on the states' authority to regulate generation resources within their borders. Section 201 of the Federal Power Act clearly reserves to the states their traditional authority "over facilities used for the generation of electric energy."[7] That authority "is a matter that has traditionally rested with the states, and it should continue to rest there."[8]

Both EO 14262 and subsequent statements by DOE make clear that the report will be used to justify Section 202(c) orders going forward.[9] The States are aggrieved by the report which paints an unrealistic picture of resource adequacy to justify use of DOE emergency authority. Exercising that authority in non-emergency situations will harm ratepayers and the environment and unlawfully infringe on an area of state sovereign authority. Moreover, our states are also purchasers of retail electricity and are directly harmed by the rate impacts from these decisions.

II. Background

a. Resource adequacy is highly regulated at the state and regional levels.

Existing regulatory mechanisms govern both federal requirements for reserve margins and state resource adequacy determinations. Resource adequacy is an integral part of prudent, least-cost, utility planning in every state and region of the country.[10] DOE plays no role in the complex proceedings to determine either reserve margins or specific resource adequacy conclusions. The Report fails to grapple with the complicated task of resource adequacy planning undertaken by state utility offices and regional grid planners across the country, yet these existing procedures are a key part of the alleged resource adequacy conundrum which the DOE Report claims to address.

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[7] 16 U.S.C. § 824(b)(1).
[8] *Devon Power LLC et al.,* 109 FERC ¶ 61,154, para. 47 (Nov. 8, 2004).
[9] *See* U.S. Dep't of Energy, Order No. 202-25-4 (May 30, 2025) [https://perma.cc/PS3M-6CJA] [*hereinafter* "Eddystone Order"] (The methodology "will be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk power system. . . . DOE plans to use [the July 7] methodology to further evaluate Eddystone Units 3 and 4.").
[10] *See* SYNAPSE ENERGY ECONOMICS & LAWRENCE BERKELEY NATIONAL LABORATORY, BEST PRACTICES IN INTEGRATED RESOURCE PLANNING 1-2 (Nov. 2024), https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf [https://perma.cc/D68F-WHWQ].

i. States directly regulate resources to ensure an adequate supply of electricity.

Most states rely on resource planning processes to ensure that adequate generation is available to meet projected demand. While some states have largely delegated this authority to the regional grid operators and rely on market-based mechanisms to ensure future demand is met, it is ultimately the state that retains regulatory authority over generation resources.[11] These state processes are transparent and iterative, relying on technical and expert analysis to ensure that adequate resources are procured in a prudent manner. The States describe just a few of the mechanisms at play in our jurisdictions as relevant examples below.

1. Arizona

Arizona, like other states, regulates the power generation, transmission, and distribution needs of the electric grid to ensure resource adequacy and reliability. This regulatory authority is established in the State's constitution. The Arizona Constitution grants the Arizona Corporation Commission ("ACC") broad authority to regulate public service corporations, including electric utilities.[12] The Arizona Constitution also empowers the ACC to set just and reasonable classifications, rates, and charges, as well as to make and enforce rules, regulations, and orders for the governance of utilities. This constitutional authority underpins the ACC's ability to establish requirements for resource planning and grid reliability.[13]

The ACC has reliability requirements in its Resource Planning and Procurement ("RPP") rules.[14] The ACC's RPP rules require load-serving entities to file and seek acknowledgement of their prospective, 15-year resource plans every three years, which include projected data for generating units and power supply systems, capital costs, environmental impacts, and cost analyses.

The most recent version of Integrated Resource Plans was authorized by the ACC on October 21, 2024,[15] which approved the power generation, transmission, and distribution acquisition plans that were submitted by Arizona Public Service,[16] Tucson Electric Power,[17] and UNS Electric.[18] The ACC requires similar data from its electric cooperatives in order to improve

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[11] 16 U.S.C. § 824(b)(1).
[12] ARIZ. CONST. art. 15, § 3.
[13] *Id.*
[14] A.A.C. R14-2-701.
[15] ACC Decision No. 79589, https://docket.images.azcc.gov/0000212120.pdf?i=1754080707112.
[16] ARIZONA PUBLIC SERVICE, *2023 Integrated Resource Plan* (Nov. 1, 2023), https://docket.images.azcc.gov/E000031965.pdf?i=1754080707112.
[17] TUCSON ELECTRIC POWER, *Tucson Electric Power 2024 Integrated Resource Plan* (Nov. 1, 2023), https://docket.images.azcc.gov/E000031960.pdf?i=1754080707112.
[18] UNS ELECTRIC, *UNS Electric 2023 Integrated Resource Plan* (Nov. 1, 2023), https://docket.images.azcc.gov/E000031961.pdf?i=1754080707112.

grid performance and reliability in rural areas of the state.[19] The decision requires technology-neutral portfolio methodologies, annual load forecast accuracy reports, and analysis of coal-fired power plant retirement timelines to enhance reliability, building on existing triannual utility analyses. It also requires sharing modeling data with stakeholders.

While one major utility in Arizona, the Salt River Project, is not subject to the ACC's jurisdiction, it has adopted its own planning and goal-setting requirements, referred to as the Integrated System Plan.[20]

2. New York

The New York Independent System Operator ("NYISO") plays a significant role in safeguarding electric grid reliability while supporting the clean energy transition.[21] As part of its biennial reliability planning process, NYISO first conducts a Reliability Needs Assessment, which examines whether New York's power grid will have enough generation, storage, and transmission capacity to meet demand over the next ten years.[22] Specifically, the Assessment uses probabilistic simulations to evaluate whether New York meets the Loss of Load Expectation (LOLE) criterion of not more than 0.1 event-days/year (equivalent to one day in ten years), which is the standard reliability criterion used by the New York State Reliability Council and the Northeast Power Coordinating Council.[23] The Assessment also evaluates how New York's environmental and energy laws—such as the Climate Leadership and Community Protection Act, which requires 100% zero-emission electricity by 2040—will affect grid reliability, especially as fossil fuel-fired power plants retire, and electricity demand increases due to building electrification and the continued growth of the electric vehicle market.[24]

Following the Reliability Needs Assessment, NYISO completes the biennial planning process by issuing a Comprehensive Reliability Plan that documents the plans for a reliable electric grid over the same ten years.[25] The Comprehensive Reliability Plan provides solutions to any shortfalls identified in the Reliability Needs Assessment, such as accelerating battery deployment, deferring certain retirements, upgrading transmission lines, or increasing demand-side participation.[26] While the 2022 Reliability Needs Assessment did not identify any actionable

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[19] ARIZONA ELECTRIC POWER COOPERATIVE, *Demand-and Supply-Side Data Filing* (Apr. 1, 2025), https://docket.images.azcc.gov/E000042810.pdf?i=1753996193952.
[20] SALT RIVER PROJECT, *Integrated System Plan* (Apr. 1, 2025), https://www.srpnet.com/grid-water-management/future-planning/integrated-system-plan.
[21] *See About Us*, NYISO, https://www.nyiso.com/about-us.
[22] *See* NYISO, 2024 RELIABILITY NEEDS ASSESSMENT (Nov. 19, 2024), https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf.
[23] *Id.* at 41.
[24] *Id.* at 23-24 fig. 13.
[25] *See* NYISO, 2023–2032 COMPREHENSIVE RELIABILITY PLAN (Nov. 28, 2023), https://www.nyiso.com/documents/20142/2248481/2023-2032-Comprehensive-Reliability-Plan.pdf (following the 2022 RNA and incorporating finding and solutions from the quarterly short term reliability process).
[26] *See id.*

reliability shortfalls, the 2023–2032 Comprehensive Reliability Plan nonetheless provided a forward-looking analysis that evaluated key risk factors related to reliability, including delays in major transmission projects, winter peaking and gas shortage risks, and extreme weather.[27]

In parallel with the biennial reliability planning process, as of 2019, NYISO also conducts a quarterly short-term reliability ("STAR") process to identify reliability needs that may arise over the next five years due to various changes in the grid, such as generator deactivations, revised transmission plans, or updated electricity demand.[28] For example, NYISO's Quarter 2 2023 STAR report, published on July 14, 2023, identified the potential for electricity supply shortfalls in New York City beginning in the summer 2025 as a result of the New York State Department of Environmental Conservation's "Peaker Rule," which seeks to reduce nitrogen oxide (NO_x) emissions from simple-cycle combustion turbines that supply backup generation during peak demand.[29] Following this STAR report, NYISO sought proposed solutions from market participants and ultimately exercised its authority under the Peaker Rule to require specific peaker units to remain operational until long-term solutions—such as the Champlain Hudson Power Express line, scheduled to enter service in spring 2026, bringing 1,250 MW of hydropower to New York City—could come online.[30] NYISO incorporates any needs or shortfalls identified in the STAR process into its biennial reliability planning process.[31]

3. Connecticut

Connecticut General Statutes § 16a-3a requires that the Department of Energy and Environmental Protection ("DEEP") prepare an Integrated Resource Plan ("IRP"). An IRP is composed of an assessment of the future electric needs and a plan to meet those future needs. It is "integrated" in that it looks at both demand side (conservation, energy efficiency, etc.) resources as well as the more traditional supply side (generation/power plants, transmission lines, etc.) resources in making its recommendations on how best to meet future electric energy needs in the state. Connecticut's current IRP was completed in 2020 and updated in 2022. DEEP is currently developing the 2025 IRP, which involves planning for the next ten years.

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[27] *Id.* at 48-67.

[28] *See Short-Term Reliability Process*, NYISO, https://www.nyiso.com/short-term-reliability-process (last visited July 28, 2025); *Reliability Planning Process and Declaring a Reliability Need: Next Steps*, NYISO (July 14, 2023), https://www.nyiso.com/-/reliability-planning-process-and-declaring-a-reliability-need-next-steps.

[29] NYISO, Short-Term Assessment of Reliability: 2023 Quarter 2 (July 14, 2023), https://www.nyiso.com/documents/20142/16004172/2023-Q2-STAR-Report-Final.pdf/5671e9f7-e996-653a-6a0e-9e12d2e41740.

[30] Press Release, NYISO, *NYISO Identifies Solution to Solve New York City Reliability Need* (Nov. 20, 2023), https://www.nyiso.com/-/press-release-%7C-nyiso-identifies-solution-to-solve-new-york-city-reliability-need.

[31] *See* NYISO, 2023–2032 COMPREHENSIVE RELIABILITY PLAN, *supra* note 25, at 30–32.

4. Colorado

Colorado regulations require every investor-owned retail electric utility and wholesale electric generation and transmission cooperative operating in the state to file an energy resource plan ("ERP") with the Public Utilities Commission ("PUC") every four years.[32] ERPs must contain electric demand and energy forecasts, evaluation of existing resources, an assessment of planning reserve margins and contingency plans for the acquisition of additional resources.[33] If an ERP includes retirement of an existing coal-fired generating facility, detailed workforce transition and community assistance plans must be filed.[34]

The planning process includes a reserve margin to meet a 0.1 days per year loss of load expectation standard.[35] Utilities use this reserve margin to propose additional generation for the planning period, where necessary. Those proposals are vetted through extensive stakeholder input and consideration by the Colorado PUC and the additional generation must satisfy availability and dispatchability criteria.[36] And where generation needs arise outside of the four-year ERP process, interim ERPs and applications for certificates of public convenience and necessity can be filed to meet those needs.[37] These proceedings are transparent and iterative and conducted with technical and expert analysis of grid conditions and ratepayer impacts.

5. Illinois

Illinois ratepayers are served by two Regional Transmission Organizations ("RTO"), Midcontinent Independent System Operator, Inc. ("MISO") and PJM Interconnection, L.L.C. ("PJM"). Central and Southern Illinois are encompassed by MISO Local Resource Zone 4 and a small portion of Northwest Illinois is included in MISO Local Resource Zone 1.[38] The service area of Commonwealth Edison Company, the load serving entity for Illinois electricity customers in Northern Illinois, is encompassed by PJM's ComEd Zone.[39] The Illinois Attorney General's office represents Illinois ratepayers who have a significant interest in resource adequacy and maintaining reliable service at least possible cost that is materially affected by the outcome of this proceeding.

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[32] 4 COLO. CODE REGS. § 723-3-3603(a).
[33] 4 COLO. CODE REGS. § 723-3-3604(b-f).
[34] COLO. REV. STAT. § 40-2-125.5(4)(a)(VII).
[35] *See* Colo. Pub. Utils. Comm'n Proceeding No. 24A-0422E, HE 109 and HE 109 ZM-1; Colo. Pub. Utils. Comm'n Proceeding No. 21A-0141E, Hrg. Exh. 115, pp. 8-10.
[36] COLO. REV. STAT. § 40-2-125.5 (4)(d)(II).
[37] *Id*.
[38] *See* MISO Tariff, Attachment VV, Map of Local Resource Zone Boundaries, https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.
[39] *See* MISO Tariff, Attachment VV, Map of Local Resource Zone Boundaries, https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.

6. Washington

Washington electric utilities file clean energy implementation plans to the Washington Utilities and Transportation Commission once every four years with a biennial update filing at the midway point of every plan.[40] They also file long term integrated resource plans every four years.[41] For investor-owned utilities, if an integrated resource plan identifies a resource need within the next four years, the utility must file a request for proposal with the Commission for approval.[42]

7. Michigan

In Michigan, ratepayers are served primarily by MISO, with a smaller portion included within PJM. In MISO, the regulation of resource adequacy planning has both a state and federal aspect. MISO member states have a capacity obligation under the MISO tariff. MISO's resource adequacy requirements, however, are designed to be complementary to the primary role of the states in ensuring resource adequacy.[43] In Michigan, the investment decisions of utilities are regulated by the Michigan Public Service Commission ("MI PSC"). Through Michigan's state Integrated Resource Planning process, the MI PSC exercises regulatory authority over utilities in order to ensure that the utilities obtain the amounts of capacity they need to meet their obligations under the MISO tariff, and that they do so at the best value to ratepayers, and with a composition of resources that otherwise complies with state law, including environmental requirements.

Michigan's IRP statute requires electric utilities whose rates are regulated by the MI PSC to periodically file an integrated resource plan. The IRP is a projection of the utility's load obligations and a plan to meet those obligations.[44] The IRP statute directs the MI PSC to approve

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[40] *See* WASH. REV. CODE § 19.405.060; WASH. ADMIN. CODE § 480-100-640, -645; *see also* WASH. UTILS. AND TRANSP. COMM'N, *Clean Energy Implementation Plans*, https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/clean-energy-implementation-plans-ceips.

[41] *See* WASH. REV. CODE § 19.280.040 to 050; WASH. ADMIN. CODE § 480-100-620, -625; *see also* WASH. UTILS. AND TRANSP. COMM'N, *Integrated Resource Plans*, https://www.utc.wa.gov/integrated-resource-plans-irps.

[42] *See* WASH. ADMIN. CODE § 480-107-009(2), -017.

[43] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, 62,606 at P 13 (2020) ("approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities ... within the [MISO] region."); *see also id*. ("MISO's proposed Tariff language explains that the resource adequacy requirements 'are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction.' In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's Auction is not—*and has never been*—the primary mechanism for its [Load Serving Entities] to procure capacity."); *Midwest Indep. Transmission Sys. Operator, Inc*., 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]").

[44] MICH. COMP. LAWS § 460.6t(3).

a plan if the MI PSC determines that it "represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."[45] To make that decision, the statute instructs the MI PSC to consider whether the IRP appropriately balances seven statutory factors: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective.[46]

The IRP statute also directs the MI PSC to establish – among other things – computer modeling scenarios that must be used to analyze the costs of possible plans in an IRP, including costs associated with plant retirement dates.[47] In Consumers Energy's 2021 IRP, for example, the company conducted modeling that compared other possible retirement dates of its J.H. Campbell coal-fired power plant to a 2025 retirement and concluded that the most cost-effective retirement date was 2025.

8. Minnesota

Since 1991, Minnesota law has required each public utility to propose a set of resource options that the utility could use to meet the electricity service needs of its customers over a forecast period of 15 years.[48] The resource options include using, refurbishing and constructing utility plant and equipment, buying power generated by other entities, controlling customer loads, and implementing customer energy conservation. The Minnesota Public Utilities Commission ("Minnesota Commission") evaluates the plan's ability to ensure reliability of utility service, keep customer's bills and utility rates as low as practicable, minimize adverse socioeconomic effects and adverse effects on the environment, and limit risk.[49] The Commission uses an extensive notice and comment process in which the utilities and stakeholders evaluate detailed modeling of demand and various resource costs. The Minnesota Commission may approve, reject or modify utility resource plans.[50] In the most recent resource plan for Minnesota's largest utility, the Minnesota Commission approved including in the resource plan a new natural-gas fired 420 MW combustion turbine plant to address peak load.[51]

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[45] MICH. COMP. LAWS § 460.6t(8)(a).
[46] *Id*.
[47] MICH. COMP. LAWS § 460.6t(1).
[48] MINN. STAT. § 216B.2422; MINN. R. ch. 7843; *see also Electric Integrated Resource Planning (IRP)*, MINN. PUB. UTILS. COMM'N, https://mn.gov/puc/activities/economic-analysis/planning/irp/ (last accessed Aug. 6, 2025).
[49] MINN. R. 7843.0600, subp. 3.
[50] MINN. STAT. § 216B.2422.
[51] MINN. PUB. UTILS. COMM'N, Dkt. No. E-002/RP-24-67; E-002/CN-23-212, Order Approving Settlement Agreement With Modifications (Apr. 21, 2025), https://www.edockets.state.mn.us/documents/%7B30F45996-0000-CF1F-80E3-5E41B2F16918%7D/download?contentSequence=0&rowIndex=3.

ii. Regional operators establish mechanisms to ensure resource adequacy and grid stability.

State primacy over resource adequacy is further complemented by the regional transmission operators. For example, MISO and PJM both have extensive processes for obtaining resource adequacy and reliability. MISO works collaboratively with its member states to ensure resource adequacy throughout its service area.[52] MISO ensures there is sufficient generation capacity through forecasting demand growth, assessing existing generation assets, and planning for new generation resources.[53] MISO accounts for state Integrated Resource Planning and also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. MISO's capacity market is intended to incentivize the development and maintenance of adequate generation resources.[54] MISO's annual Planning Resource Auction ("PRA") procures sufficient resources and allows market participants to buy and sell capacity via the auction.[55]

Resource adequacy within the PJM footprint is subject to an established, extensive, layered, framework of oversight and regulation. The resource adequacy contribution of each PJM electric generating plant operating is subject to ongoing, technical reviews by PJM, pursuant to its tariff, and in conformity with rules promulgated and periodic grid reliability reviews conducted by Reliability First Corporation and NERC, respectively.[56] PJM also conducts an auction, its base residual auction ("BRA"), for the procurement of capacity from generating resources.

b. Historic use of 202(c) is limited.

Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), grants the Secretary of Energy the authority to issue orders that require the "temporary connection[]" of power plants and the "generation, delivery, interchange, or transmission of electric energy" in order to address certain emergencies "and serve the public interest."[57] The law also effectively waives compliance with "any Federal, State, or local environmental law or regulation" that would conflict with any

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[52] *System Planning*, MISO, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited July 30, 2025).
[53] *Id.*
[54] *Id.*
[55] *Resource Adequacy*, MISO, https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc (last visited July 30, 2025).
[56] *See, e.g., North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom*. *Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); Order No. 748, Final Rule, 134 FERC ¶ 61,213 (2011). FERC approved regional reliability standards applicable to PJM, developed by RFC and submitted to FERC by NERC. *Notice of Proposed Rulemaking on Plan. Res. Adequacy Assessment Reliability Standard*,133 FERC ¶ 61,066 (2010) (proposed rule for RFC); *Plan. Res. Adequacy Assessment Reliability Standard*, Order No. 747, 134 FERC ¶ 61,212 (2011) (final approval of RFC's Resource Adequacy Reliability Standard).
[57] 16 U.S.C. § 824a(c)(1).

party's obligations under such an order, but limits the length of any order that conflicts with a pollution control requirement to 90-days, with extension possible.[58]

That authority originated principally as a wartime power of what was then the Federal Power Commission. Section 202(c) was enacted in 1935, in the leadup to World War II, with the same "emergency" language that exists in the statute today, specifically to guard against energy related shortages that were viewed as hampering national security during World War I.[59] It was initially used largely to issue "interconnection" orders specifically between utilities at a time when America's electric grid was more fragmented, monopolized, and less diversified than it is today.[60] Interconnection was seen as a powerful means to increase grid reliability, but the federal government largely lacked regulatory power over the electric sector at the time.[61] The then-Federal Power Commission did not invoke its emergency authority until the United States entered World War II.[62] Section 202(c) orders were issued repeatedly during the war, primarily to order interconnection between utilities, but the provision was rarely invoked once the war ended. A number of organizational changes ensued in the decades following the War and the provision's authority eventually came to rest with the Secretary of Energy.[63]

From 2000, when the authority of Section 202(c) was "rediscovered" in response to the California Energy Crisis, through 2024, the provision was sparingly invoked to respond to true emergencies to avoid imminent widespread blackouts.[64] Most 202(c) orders issued during this period involved natural disasters or other acute power outages.[65] These emergencies included one high-profile incident near the nation's capital that led to the statute's 2015 amendment, adding the provisions explicitly waiving environmental liability due to compliance with a Section 202(c) order, leading the statute to read as it does today.[66] Orders issued during this period were typically of limited duration, lasting for a period of days to weeks.[67]

The typical process for issuing a Section 202(c) order is outlined by DOE implementing regulations at 10 C.F.R. §§ 205.370-379. In the normal course, requests for Section 202(c) orders originate with a grid operator or utility facing an acute and unforeseen emergency that normal processes and demand response mechanisms are incapable of addressing, though they may be issued by the Department unprompted as well.[68] Applications for Section 202(c) orders made by

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[58] *Id.* at § 824a(c)(3)-(4).
[59] For a deeper discussion of the history of Section 202(c), see Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789 (2025). *See also id.* at 798-802.
[60] *Id.* at 802-804.
[61] *Id.* at 801-802.
[62] *See id.* at 803 n.82 *and accompanying text*.
[63] *Id.* at 803-04; 42 U.S.C. § 7151(b).
[64] *Id*. at 805-509.
[65] Rolsma, *supra* note 59, at 805-09, 839-42 tbl.1.
[66] *Id.* at 806-08 (citing DEP'T OF ENERGY, ORDER NO. 202-05-3 (Dec. 20, 2005)); 16 U.S.C. § 824a(c)(3)-(5).
[67] *See* Rolsma, *supra* note [x], at 839-42 tbl.1 (chronicling all Section 202(c) orders issued "after dissolution of the Federal Power Commission").
[68] *See* 10 C.F.R. § 205.370.

outside entities are to include specific details to "be considered by the DOE in determining that an emergency exists" and the appropriate intervention.[69] This information is supposed to include "[d]aily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the emergency," "[a] description of the situation and a discussion of why this is an emergency, … includ[ing] any contingency plan of the applicant and the current level of implementation," and "[a] description of efforts made to obtain additional power through voluntary means and the results of such efforts."[70] Section 202(c) orders bypass environmental review under NEPA and can waive pollution control requirements that would otherwise apply to the facilities.[71]

c. President Trump Declares a National Energy Emergency on his first day in office and subsequently issues EO 14262.

On January 20, 2025, his first day in office, President Trump issued Executive Order 14156 titled "Declaring a National Energy Emergency".[72] That unilateral declaration did not provide any factual support for its assertion that emergency conditions had overtaken the electricity grid.[73]

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[74] Section 3(b) of the executive order directs the Secretary of Energy (Secretary) to:

> develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy.[75]

It further requires that the methodology in the Report (Methodology) "be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order," or July 7, 2025.[76]

The Executive Order describes the featured role that the Report will play in future DOE actions. EO 14262 § 3 is titled "Addressing Energy Reliability and Security with Emergency Authority" and § 3(c) directs the Secretary to "establish a process by which the [Methodology],

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[69] 10 C.F.R. § 205.373.
[70] 10 C.F.R. §§ 205.373(a)-(o).
[71] *See, e.g.*, *Environmental Integrity Project v. DOE*, 471 F. Supp. 3d 132 (D.D.C. 2023).
[72] 90 Fed. Reg. 8433.
[73] *See Id*. (providing no factual support for claimed emergency). Many of the States have since joined litigation challenging that declaration. *See* Complaint, *Washington v. Trump*, NO. 2:25-cv-00869 (W.D. Wa. May 9, 2025).
[74] The EO was signed alongside Exec. Order No. 14261, Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241, 90 Fed. Reg. 15517 (Apr. 8, 2025), at a White House event with members of the coal industry.
[75] Exec. Order No. 14262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025).
[76] Exec. Order No. 14262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025) (referring to § 3(b)(iii)).

and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability."[77] It indicates the protocol shall "include all mechanisms available under applicable law, including Section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region."[78] In short, Executive Order 14262 instructs DOE to publish a methodology by July 7, 2025 that will form the basis for future exercises of its Section 202(c) authority.

d. DOE's 2025 Emergency Orders Preventing the Retirement of Fossil Fuel Power Plants.

Since January 20, 2025, the U.S. Department of Energy (DOE) has issued five emergency orders under Section 202(c) of the Federal Power Act (FPA), a sharp uptick from the less than one order per year issued on average from 2017-2024.[79] Three of these orders were largely in line with DOE's historic Section 202(c) practice – allowing units to modify their operations in response to acute risks to the grid.[80] However, in late May 2025 DOE issued a pair of Section 202(c) orders requiring facilities that were slated to retire the very next business day to remain on-line. These orders represent a marked shift in how Section 202(c) has historically been used.[81]

For example, the orders for the J.H. Campbell Generating Station in Michigan and the Eddystone Plant in Pennsylvania, both previously slated for retirement, cited general concerns about resource adequacy and not any acute emergency. In Michigan, regulators warned that the Campbell order would place upward pressure on ratepayers, particularly in Consumers Energy's service territory, where decommissioning costs were already being recovered through base rates. One Michigan regulator estimated that the costs of complying with DOE's order for 90 days would approach $100 million.[82] Consumers Energy has since disclosed that continued operation

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[77] Exec. Order No. 14262, 90 Fed. Reg. 15521, 15522 (Apr. 8, 2025) (referring to § 3).
[78] Exec. Order No. 14262, 90 Fed. Reg. 15521, 15522 (Apr. 8, 2025) (referring to § 3) (emphasis added).
[79] U.S. DEP'T OF ENERGY, *DOE Issues 202(c) Orders to PREPA for Grid Stability*, https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.
[80] *See* Duke Energy Carolinas (Order No. 202-25-5) (allowing increased operations to support grid stability); H.A. Wagner (Order No. 202-25-6) (allowing exceedance of operational limit – but maintained compliance with pollution control requirements – to allow units to respond to demand); PREPA (Order No. 202-25-1) (requiring measures to mitigate outage risks during high load conditions)
[81] U.S. Dep't of Energy, Order No. 202-25-3 (May 23, 2025), https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf [https://perma.cc/Q7P7-TDTX] [*hereinafter* "Campbell Order"]; Eddystone Order, *supra* note 9.
[82] *See, e.g.*, Ella Nilsen, *The Trump Admin Ordered a Coal Power Plant to Stay On Past Retirement. Customers in 15 States Will Foot the Bill*, CNN (June 6, 2025), https://www.cnn.com/2025/06/06/climate/michigan-coal-plant-energy-cost-wright.

of the plant in the first five weeks since the Order was issued has resulted in a net financial impact of $29 million.[83]

e. DOE Publishes its Methodology and Reliability Standard to Guide Future Section 202(c) "Reliability Interventions."

On July 7, 2025, DOE published a "Report on Evaluating U.S. Grid Reliability and Security," which set forth the methodology and reliability standard that the Executive Order had mandated. *See* Report at *vi* (hereinafter, "the Report"). DOE stated the methodology "will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States." *Id*. Despite this statement, DOE has not explained how or when it will re-assess the methodology and, to date, has not involved the public in the creation of the methodology or offered an opportunity for public comment on the methodology.

i. DOE did not provide public notice or an opportunity for comment on the Report.

Before publishing the Report, DOE provided no public notice or request for comment on methods or reliability standards that DOE was considering. DOE did not consult with the undersigned States or, to the States' knowledge and belief, consult with any grid operator or other State on appropriate mechanisms to ensure grid reliability and grid reliability issues around the country.[84] Other than the statements in the Report, DOE has not made the underlying data or models available to allow the public to reproduce or test DOE's analysis. DOE has not requested public comment on the Report, opened any administrative proceeding to otherwise involve the public in DOE's methodology, or published the Report in the Federal Register.

DOE has confirmed, consistent with the Executive Order's mandate, that it will rely on the Report to justify future Section 202(c) orders.[85] DOE explained in the June 2025 Eddystone Order that it would use the forthcoming Report "to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk power system[,]" including potential Section 202(c) orders extending DOE's Eddystone Order.[86] DOE also issued the Report with a "Fact Sheet,"

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[83] *See supra* notes 5-6 *and accompanying text*; NRDC, *Trump Administration's DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target* (June 16, 2025), https://www.nrdc.org/bio/derrell-e-slaughter/trump-administrations-doe-forcing-coal-plants-stay-open-michigan-first.
[84] *See* Report at i (acknowledging lack of data from regional and utility levels).
[85] See Report at vi (explaining that DOE's standard will be used to "guide reliability interventions"), 1 (emphasizing the need for DOE's "decisive intervention" in energy markets), 10 (analyzing ERCOT because "FPA Section 202(c) allows DOE to issue emergency orders to ERCOT").
[86] Eddystone Order, *supra* note 9.

wherein DOE explained that the methodology will be used to "prevent [] generation resources from leaving the bulk-power system."[87]

ii. DOE's analysis rests on key assumptions about load growth, retirements, and capacity additions.

The Report's analysis rests on assumptions about future electricity demand (referred to as "load growth"), anticipated retirements of existing facilities ("retirements"), and future electricity generation sources (referred to as "capacity additions"). DOE made additional assumptions, some explicit and others implicit, which the States have not yet been able to fully analyze or comment on here.[88]

Regarding load growth, DOE assumes 101 Gigawatts ("GW") of new load will be added to the grid by 2030.[89] DOE projects that data centers, especially for developing Artificial Intelligence ("AI"), will add 50 GW of that new load, and other demand growth will add 51 GW. DOE appears to assume that data-center load will be "firm," meaning electricity to meet that demand must be guaranteed at all times.[90] That is in contrast to "interruptible" load for which supply can be reduced during peak periods.[91] DOE also appears to assume that all the new data centers will connect to the grid, rather than rely on "behind-the-meter" generation and that regulators and grid operators will allow every MW of new load to connect to the grid on a firm basis, even if doing so threatens the grid's reliability.[92] Based on these assumptions, DOE projects a 15% increase in load by 2030.[93]

The Report assumes 51 GW of non-data-center load, purportedly based on the NERC's 2024 ITCS projections.[94] DOE does not explain why using projections from a NERC report on inter-regional transmission is reasonable or why those projections are reliable for DOE's purposes. Additionally, NERC's 2024 projections likely already include some data center load expectations, as well as policies to encourage the electrification of transportation, heating and cooling, and other energy uses that the Trump Administration has rescinded or is planning to

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[87] U.S. DEP'T OF ENERGY, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [https://perma.cc/YLX7-8G7T]; *see also* Press Release, U.S. Dep't of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security [https://perma.cc/8TEJ-AGH6] (stating that its "methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act").
[88] *See generally* Report at 10-19.
[89] Report at 2-3.
[90] Report at 18.
[91] *Id.*
[92] *See id.* at 2-3, 15-18.
[93] *See* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report* (July 11, 2025), https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/ [https://perma.cc/GN56-VLNA].
[94] *See* Report at 11.

rescind.[95] DOE apparently did not account for shifting electrification policies in its load projections.

Regarding retirements, DOE assumed 104 GW of "firm capacity" retirements by 2030, roughly three-quarters from coal-fired power plants and one-quarter gas plants.[96] *Id*. at 5; see also Report at 3, 12-13, A1-A8. DOE included approximately 50 GW of "confirmed retirements," retirements that have been formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date.[97] DOE also included approximately 50 GW of "announced retirements," which are generators that have publicly stated retirement plans but not formally notified system operators or initiated the retirement process.[98]

Regarding capacity additions, DOE took a more conservative approach. Rather than including all announced projects, DOE assumed "that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built." Report at A-5. These projects, known as Tier 1 resources, are by their very nature likely to be built in the short term. As a result, DOE assumed "minimal capacity additions beyond 2026." *Id*. In addition, DOE does not appear to have modeled new transmission projects, despite their grid reliability benefits.

The Report's assumptions about load growth and electricity supply differ significantly from other forecasts.[99] As one grid reliability expert commented, DOE's report "used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026."[100] For example, DOE assumed 15% load growth by 2030, but the U.S. Energy Information Agency recently assumed just 6% in their "high" growth" case.[101] Other differences with the Energy

[95] *See* NERC, 2024 Long Term Reliability Assessment Report 8 (July 15, 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf [https://perma.cc/NMP4-KRN5] (discussing how "the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America").
[96] Report at 5.
[97] *Id.* at 12; *see also* O'Connell, *supra* note 93.
[98] Report at 12.
[99] Report at 2 (noting that demand forecasts vary widely).
[100] O'Connell, *supra* note 93.
[101] U.S. Energy Information Administration, Form EIA-860 (June 11, 2025) https://www.eia.gov/electricity/data/eia860/.

Information Agency forecasts are described in the chart below:[102]

DOE Report Assumptions vs. U.S. Energy Information Administration Data:

	DOE Report	EIA 860
Load growth:	101 GW	N/A
Capacity Additions	209 GW	200 GW
Gas Capacity Additions	22 GW	35 GW
Battery Capacity Additions	31 GW	53 GW
Retirements	104 GW	52 GW

The Report also does not address actions already being taken by states, utilities, and regional grid operators to meet increased load growth or how markets are already responding to increasing demand. As GridLab explained in its analysis:

> Markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that could add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.[103]

iii. Based on these assumptions and DOE's resource adequacy standard, DOE concluded intervention in electricity markets is needed to prevent outages.

DOE then adopted a novel "resource adequacy standard," using a combination of non-traditional and non-standardized metrics ("Loss of Load Hours" and "Normalized Unserved Energy").[104] DOE selected the target to be achieved with each metric.[105]

DOE did not define what energy sources it considered "firm" capacity or why only those sources provide the necessary attributes for grid reliability. DOE's usage of the term in the report suggests that only coal or gas power plants count as "firm" capacity and excluded other sources that could provide similar, greater, or different levels of reliability (like batteries or transmission) from its analysis.[106]

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[102] O'Connell, *supra* note 93.
[103] *Id*.
[104] Report at 3-4.
[105] *Id.*
[106] *See, e.g.*, *id.* at 1, 32, 37.

DOE portrayed three scenarios in an attempt to assess the impact of planned retirements on resource adequacy in 2030.[107] The first scenario is "Plant Closures," which assumes that announced retirements and capacity additions "in the final stages for connection" that are "either under construction or ha[ve] received approved planning requirements" will occur.[108] The second scenario is "No Plant Closures," which has the same assumption about additions as the "Plant Closures" scenario but assumes no retirements.[109] The third scenario is "Required Build" which uses the "Plant Closures" scenario's assumptions about retirements and then artificially adds enough hypothetical perfect capacity to the system to meet DOE's new reliability standard.[110] Perfect capacity is hypothetical capacity that experiences no outages and is used in the modeling "to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations."[111]

DOE then concluded, based on the above assumptions, the risk of power outages in 2030 would be 100 times higher in 2030 than it is today.[112] DOE concluded that "decisive intervention" and "robust and rapid reforms" are necessary to avoid this result and to accommodate "projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.[113] Numerous grid experts have commented on the shortcomings of this approach.[114]

III. Statement of Issues and Specification of Errors.

1. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure Act and Federal Power Act because it suffers from numerous analytical, mathematical, and empirical flaws, including but not limited to the following:
    a. DOE relies on key assumptions about load growth, retirements, and capacity additions that are unreasonable and unsupported by evidence or logic.

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[107] *Id.* at 3, 5.
[108] *Id.* at 4-5.
[109] *Id.*
[110] *Id.*
[111] *Id.* at 5.
[112] *Id.* at 1.
[113] *Id.*
[114] *See, e.g.*, Jeff St. John, *Critics Fear Trump Will Use Flawed DOE Report to Push Pro-Coal Agenda*, CANARY MEDIA (July 14, 2025), https://www.canarymedia.com/articles/fossil-fuels/trump-doe-report-open-coal-plants [https://perma.cc/2T7L-3FWX]; Matthias Fripp & Brendan Pierpont, *Energy Department's Flawed Grid Study Props Up Expensive, Zombie Power Plants*, UTILITYDIVE (July 24, 2025), https://www.utilitydive.com/news/doe-grid-reliability-study-zombie-power-plants/753596/ [https://perma.cc/QH3V-KM5R]; INST. FOR POL'Y INTEGRITY, ENOUGH ENERGY: A REVIEW OF DOE'S RESOURCE ADEQUACY METHODOLOGY (July 2025), https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf [https://perma.cc/WN39-K9LE].

b. DOE assumes the transmission grid will remain static over the next five years and fails to consider how new transmission projects in development will impact reliability.
c. DOE fails to define "firm power capacity" or reasonably explain why DOE apparently considers only coal and gas to be "firm power capacity" when other generation sources, energy storage, or transmission could provide similar or greater reliability attributes.
d. DOE's assumptions unreasonably presume that the market, grid operators, and state regulators will take no action in the next five years to address load growth or reliability issues, and that no alternative other than preserving aging coal and gas power plants will ensure grid reliability.
e. DOE's analysis suffers from mathematical errors, analytical flaws, and lacks sufficient data or regional input. Those flaws are amply described in the attached analysis by the Institute for Policy Integrity and are incorporated and adopted here. *See* IPI Report (attached as Ex. XX).
f. Although DOE acknowledged that data and input from states and regional entities could improve the analysis, DOE chose not to consult with those entities or seek to obtain that data.
g. DOE selected non-traditional and non-standardized resource adequacy metrics and targets to be achieved without providing a reasoned explanation for its choices, including why it selected Normalized Unserved Energy ("NUSE") and Loss of Load Hours ("LOLH") instead of other possible metrics that would provide different data, an explanation of the costs and benefits of its choices and the target to be achieved, and why a nationwide target is appropriate despite regional differences in the costs and benefits with regard to resource adequacy.
h. DOE offers no reasonable explanation how the Report could be used to identify "at-risk region[s] and guide reliability interventions" when it arbitrarily relies on geographic groupings that do no match boundaries used by utilities, balancing authority areas, transmission planning regions, regional wholesale markets, NERC regional entities, or NERC reliability coordinators to reliably operate the nation's electric grid.

These assumptions and omissions work together to arbitrarily tip the scales in favor of finding a resource adequacy risk. *See Motor Vehicles Mfrs. Ass'n v. State Farm*, 463 U.S. 29, 43 (1983); *WildEarth Guardians v. U.S. Bureau of Land Mgmt*., 870 F.3d 1222, 1237 (10th Cir. 2017); *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1391 (D.C. Cir. 1985); *see also infra* Section 4.a.

2. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it pursues an extra-statutory motive of preserving aging and uneconomic fossil fuel

power plants at consumer expense, which contradicts the Federal Power Act's express goal of preserving just and reasonable rates and preventing undue discrimination or preference. The Administration's energy actions, when viewed collectively, also demonstrate that DOE has prejudged the outcome of this proceeding and intended its analysis to reach only one result: preventing the retirement of fossil-fueled power plants. *See Dep't of Com. v. New York*, 588 U.S. 752, 785 (2019); *Gresham v. Azar*, 950 F.3d 93, 104 (D.C. Cir. 2020), *vacated as moot*, *Becerra v. Gresham*, 142 S. Ct. 1665 (2022). *See also infra* Section 4.a.iii-iv.

3. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it purports to guide emergency action under Section 202(c) of the Federal Power Act but does not describe an "emergency" within the meaning of the Federal Power Act or DOE's implementing regulations. *See* 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; *Otter Tail Power Co. v. Federal Power Com.*, 429 F.2d 232, 234 (8th Cir. 1970). *See also infra* Section 4.b.

4. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it "fails to consider an important aspect of the problem" and fails to consider reasonable alternatives. Specifically, the Report ignores alternatives, or in some cases actively prevents viable alternatives with no explanation, such as expanding interregional transmission, batteries, renewable energy, incorporating data centers flexibly into load, and the existing resource adequacy mechanisms that are used by states and regional grid operators to assess reliability and respond to resource adequacy needs. *See State Farm*, 463 U.S. at 43. *See also infra* Section 4.a. (arbitrary and capricious) and section 4.c. (existing resource adequacy mechanisms)].

5. The Report is *ultra vires* and contrary to law in violation of the Administrative Procedure and Federal Power Acts because it intrudes upon matters reserved for the States and the Federal Energy Regulatory Commission. DOE does not possess authority to set nationwide resource adequacy standards or regulate sources of electricity generation. *See* 16 U.S.C. § 824b(1); *Whitman v. Am. Trucking Ass'ns, Inc.*, 531 U.S. 457, 468 (2001). *See also infra* Section 4.d.

6. The Report violates the Administrative Procedure Act, 5 U.S.C. 553, because it establishes a legislative rule without first providing public notice and comment. *See Shalala v. Guernsey Mem'l Hosp.*, 514 U.S. 87, 99–100 (1995); *Nat'l Min. Ass'n v. McCarthy*, 758 F.3d 243 (D.C. Cir. 2014); *Children's Health Care v. Centers for Medicare & Medicaid Servs.*, 900 F.3d 1022 (8th Cir. 2018). *See infra* Section 4.e.

7. The Report is arbitrary, capricious, and contrary to law in violation of the Administrative Procedure Act because it allegedly supports issuing Section 202(c) emergency orders based on factors and procedures that conflict and are inconsistent with DOE's existing regulations. *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39,984 – 39,989 (Aug. 6, 1981); 10 C.F.R. §§ 205.371 *et seq*. *See infra* Section 4.e.ii.

8. The Report is arbitrary and capricious in violation of the Administrative Procedure Act because DOE failed to acknowledge that its methodology and protocol for issuing Section 202(c) orders is inconsistent with the factors for determining when an emergency exists that DOE's regulations already set out. *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. at 39,985; 10 C.F.R. §§ 205.371, 205.373. It is also inconsistent with DOE's previous position that emergency orders are inappropriate for long-term reliability issues and a "utility must solve long-term problems itself." 46 Fed. Reg. at 39,985; *see also* 10 C.F.R. § 205.371. Agencies act arbitrarily when they fail to display awareness that they are changing position and offer good reasons for the change in policy. *See Food & Drug Administration v. Wages & White Lion Invs*., 604 U.S. ---, 145 S. Ct. 898, 918 (2025); *see also infra* Section 4.e.

IV. Request for Rehearing

a. DOE's Report is Based on Flawed and Arbitrary Assumptions and is Unsupported by Substantial Evidence.

The Report's conclusions rest on critical assumptions about load growth, retirements, and capacity additions, but DOE did not reasonably explain how it arrived at those assumptions or support its choices with substantial evidence. At times, DOE's assumptions are internally inconsistent and arbitrarily tip the scales in favor of finding a need to prevent scheduled retirements. The Report also seems to adopt a definition of "firm capacity" that includes only fossil-fuel power plants, but does not explain why other generation sources or batteries are not also "firm capacity." DOE has also failed to make the data it relied on publicly available – rendering it impossible to fully test DOE's analysis.[115]

[115] Due to the lack of public notice or any consultation or opportunity for involvement in the DOE's development of this report, the States have not had an opportunity to fully analyze DOE's methodology. DOE also has not made the data or models it used publicly available, which would allow the States to critically assess or replicate DOE's analysis and uncover additional flaws in DOE's approach. As such, the States reserve the right to raise additional flaws with DOE's analysis and conclusions at a later date, as they continue to analyze the Report.

Agencies act arbitrarily when they base decisions on key assumptions that are irrational or unsupported.[116] Moreover, when agencies use complex models, they must publicly reveal the assumptions and data incorporated into their models and "provide a full analytical defense" of their model.[117]

i. DOE fails to reasonably explain or support its load growth assumptions

DOE assumes 15% load growth by 2030, half of which DOE assumes will serve new data centers.[118] In doing so, DOE presumes – without evidence or a rational explanation – that data center load is firm (i.e., it cannot be interrupted at peak times). That assumption is arbitrary and directly undermined by recent advances in both policy and technology.

Some policymakers are already requiring data centers to be flexible, interruptible load.[119] In Texas, for example, a new law grants ERCOT more flexibility to curtail certain data center loads in the event of a grid emergency.[120] DOE did not grapple with the impact of this law on its underlying assumptions despite the fact that curtailing such load during peak hours "could go a long way towards avoiding the DOE-identified resource adequacy problem" in ERCOT.[121]

DOE also ignores the possibility of industry reducing its demand for electricity either as a matter of policy or innovation in this rapidly developing field. NVIDIA, the foremost supplier of hardware for AI data centers, recently announced a new power supply unit that can reduce peak grid demand by up to 30%.[122] In another recent example, Google agreed to a demand response framework with two utilities that would reduce how much electricity is used by its data centers during peak hours.[123]

DOE's reliance on an inflexible assumption for data center load reflects a failure to consider how this rapidly developing industry may adapt to address its significant energy

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[116] *WildEarth Guardians v. U.S. Bureau of Land Mgmt*., 870 F.3d 1222, 1237 (10th Cir. 2017); *Hisp. Affs. Project v. Acosta*, 901 F.3d 378, 389 (D.C. Cir. 2018) (noting agencies' affirmative duty to examine key assumptions underlying their policies).
[117] *Nat. Res. Def. Council, Inc. v. Herrington,* 768 F.2d 1355, 1385 (D.C. Cir. 1985); *see also Columbia Falls Aluminum Co. v. EPA*, 139 F.3d 914, 923 (D.C. Cir. 1998).
[118] Report at 18.
[119] *See* Ex. D, Nicholas Institute Report at 25; *see also* Ex. C, IPI Report at 24
[120] S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170); *See also* Ex. C, IPI Report at 26.
[121] Ex. C., IPI Report at 26.
[122] Meris Lutz, *NVIDIA addresses AI peak power demand, spikes in new rack-scale systems*, UtilityDive (July 30, 2025), https://www.utilitydive.com/news/nvidia-rack-scale-system-smooth-ai-power/756279/.
[123] Laila Kearney, *Google agrees to curb power use for AI data centers to ease strain on US grid when demand surges*, Reuters (Aug. 4, 2025), https://www.reuters.com/sustainability/boards-policy-regulation/google-agrees-curb-power-use-ai-data-centers-ease-strain-us-grid-when-demand-2025-08-04/.

demand. This renders DOE's blunt conclusions regarding resource adequacy arbitrary and capricious.[124]

The Report also adopts an unreasonably high estimate of future data center load, arbitrarily claiming it is simply adopting a "midpoint assumption." Report at 15. DOE admits that there are "wide variations" in estimates of future data center load growth, yet the agency does not appear to have conducted any actual evaluation of those estimates to determine their respective accuracy. DOE must explain why its adoption of an estimated 50 GW load growth is more reliable or likely than other projections. It cannot just pick what it calls a "midpoint" from available studies and move forward. A rational approach would involve projecting future growth under a number of scenarios. Indeed, DOE did not account for a number of factors that temper against aggressive assumptions for future data center load growth. Those factors include the fact that data center developers often make duplicative requests for service; that data center deployment is limited by the availability of chips and processing systems; that data center efficiency may increase in the future as technology develops; and that utilities are incentivized to adopt aggressive load forecasts.[125]

The Report also assumes an additional 51 GW of non-data center load growth. DOE states that it adopted this assumption from NERC's 2024 ITCS Report. But NERC's 2024 ITCS Final Report does not contain its own load growth projections.[126] DOE has not cited which NERC projections it is relying on, what data underlie those projections, or why DOE considers it reliable for purposes of setting a uniform resource adequacy standard and guiding reliability interventions. Moreover, NERC's forecasts already contain data center load expectations meaning the Report may be double counting projected future demand from data centers.[127] NERC's forecasts may also contain other assumptions that are no longer appropriate, such as demand forecasts based on federal incentives to electrify transportation that no longer exist. Additionally, as the Institute for Policy Integrity explains in its report, DOE's method for distributing load growth across the country is questionable and does not necessarily reflect actual market decisions.[128]

ii. DOE arbitrarily assumes 104 GW of retiring capacity by 2030 but only 22 GW of additions in the same time period.

The Report also assumes the retirement of 104 GW of generating capacity by 2030, an extremely aggressive estimate that cannot withstand any level of scrutiny. [129] That assumption is inconsistent with the U.S. Energy Information Administration's data from June 2025 showing

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[124] *See* Report at 17, 40; *see also* Ex. C, IPI Report at 26 ("DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT").
[125] *See generally* Ex. E, London Economics International Report.
[126] Ex. A, NERC ITCS Report.
[127] Report at 17.
[128] See Ex. C, IPI report at 24; *see also* Ex. E, LEI Report at 10-14 (noting that data centers have many choices where to locate).
[129] *See* Report at 5, A-5.

only half of that capacity is actually set for retirement. [130] This projection is also flawed because it arbitrarily includes announced retirements even though those generators have not formally provided notice of their retirement or initiated the retirement process. [131] Many of these resources have, however, pushed back their actual retirement dates due to changing market conditions and the policies of the current administration.[132]

At the same time that the Report overestimates the amount of load growth and retirements by 2030, it underestimates capacity additions that can be reasonably expected to come online in that same timeframe. DOE assumes only Tier 1 projects will be built by 2030. Because Tier 1 additions are projects that are either under construction or received approved planning requirements, nearly all will be in service by 2026.[133] DOE acknowledged that the Tier 1 assumption "results in minimal capacity additions beyond 2026," Report at A-5, yet DOE did not explain why that assumption was nonetheless reasonable when forecasting conditions to 2030.

By focusing solely on Tier 1 projects, DOE excludes announced capacity additions or even capacity additions that are seeking approval to interconnect to the grid (NERC "Tier 2" projects).[134] Excluding capacity that has been requested but has not yet received approval for planning requirements does not make sense for predictions stretching out five years from now. Both common sense and history suggest that at least some of these additions will receive approval in that time.[135] DOE has thus adopted a view of generator additions that is completely at odds with its projection of generator retirements and together the approach arbitrarily tips the scales in favor of finding a resource adequacy risk.

These assumptions seem to ignore a fundamental property of market dynamics: that supply will respond to rising demand. DOE assumes that generators who have not initiated the retirement process will retire even if remaining in the market would still be economic for them. And DOE assumes that developers will refrain from building any new energy projects from 2027-2030 despite market signals that additional capacity is needed. Those assumptions are unreasonable and render the Report arbitrary and capricious.[136]

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[130] U.S. Energy Information Administration, Form EIA-860 (June 11, 2025) https://www.eia.gov/electricity/data/eia860/.
[131] *See* Report at 5, A-5.
[132] Kevin Clark, *Where coal plant retirements are happening – And what could delay them*, Power Engineering (July 14, 2025), https://www.power-eng.com/coal/plant-decommissioning/where-coal-plants-are-closing-and-what-could-delay-them/. *See also,* Joe Schulz, *We Energies will delay Oak Creek coal plant retirement by one year to 2026*, Wisconsin Public Radio (June 26, 2025), https://www.wpr.org/news/we-energies-delay-oak-creek-coal-plant-retirement-2026. See also Ex. C, IPI Report at 23-24 (explaining why DOE's retirement figure likely overstates retirements).
[133] NERC, *2024 Long-Term Reliability Assessment* at 22, 136-37 (2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.
[134] *Id*.
[135] *See also* Ex. C, IPI Report at 21-22 (applying historical statistics and data to demonstrate why DOE's exclusion of Tier 2 additions is unreasonable).
[136] *See* Report at 1 (concluding that, based on its model, intervention is needed to ensure a reliable power grid and meet the AI growth requirements).

DOE also arbitrarily excludes new transmission projects from its analysis altogether. Interregional transmission improvements are known to be one of the most cost-effective ways of improving grid reliability.[137] DOE apparently assumes that the nation's transmission will remain static over the next five years, despite ongoing planning processes and reforms to increase transmission projects and the well-documented reliability benefits that more transmission can provide.[138] DOE also appears to undercount the reliability benefit of existing transmission systems in its analysis.[139] It is nonsensical to ignore the benefits of new transmission when DOE is purportedly seeking to improve the reliability of the electric grid and keep costs affordable for consumers.

iii. DOE's analysis lacks sufficient regional granularity and suffers from other analytical flaws.

DOE's analysis also suffers from mathematical errors, analytical flaws, and lacks sufficient data or regional input further highlighting the importance of leaving resource adequacy to the states. DOE itself recognized that the Report's lack of regional data was a shortcoming that undercut its conclusions. As DOE acknowledges, "[e]ntities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience."[140] Despite this admission, DOE made no attempt to consult with States or grid operators on reliability issues or to obtain this data. An agency "may not tolerate needless uncertainties in its central assumptions when the evidence fairly allows investigation and solution of those uncertainties."[141]

This lack of state and regional granularity contributes to the report's unreasonable assumptions and overstated conclusions. Rather than focus on a region-specific analysis, DOE engaged in broad approximations to allocate nationwide projections to the various regions. For example, DOE started with a nationwide estimate of 50 GW of incremental data center load, allocated it across regions using state-level growth ratios from S&P's forecast, then mapped these state-level projections to the regions used for its analysis, the NERC Transmission Planning Regions (TPRs).[54] It is also unclear how DOE accomplished this mapping, given that the referenced NERC TPRs do not perfectly map to states.[56]

Further, the Report's conclusions regarding resource adequacy are contradictory at times, even within a single region, rendering DOE's characterization of certain regions' resource adequacy arbitrary and capricious. To guide its assessments, DOE set reliability standards of "[n]o more than 2.4 hours of lost load in an individual year" and "[n]o more than an NUSE [Normalized Unserved Energy] of 0.002%."[142] In its analysis of the PJM region, the Report highlights PJM's average loss of load figure of 2.4 hours under the current system analysis, apparently to indicate resource inadequacy despite clearly not *exceeding* the threshold DOE set,

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[137] *See generally* Ex. A, NERC ITCS Report; *see also* Ex. F, GridStrategies Report at 1.
[138] *See generally* Ex. A, NERC ITCS 2024 Report (identifying areas where new transmission can significantly improve reliability); Ex. F, GridStrategies, Resource Adequacy Value of Interregional Transmission (June 2025)
[139] *See* Ex. C, IPI Report at 25.
[140] Report at i.
[141] *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1391 (D.C. Cir. 1985).
[142] Report at 4.

while also describing the region's current system as "experienc[ing] shortfalls, but … below the required threshold."[143] At the same time, the Report notes that "[f]or the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM," despite the Report's summary of the PJM's modeled NUSE metric in the current system clocking in at 0.0008%, again clearly meeting the reliability threshold that DOE itself selected.[144]

The Report also fails to explain how it could be used to identify "at-risk region(s) and guide reliability interventions"[145] while relying on many geographic groupings that do not match the boundaries used by utilities, balancing authority areas, transmission planning regions, regional wholesale markets, NERC regional entities, or NERC reliability coordinators to reliably operate the nation's electric grid.

For example, the "Front Range" region in the Report includes Colorado and portions of New Mexico and Wyoming but those boundaries are geographically different from regions analyzed in NERC's reliability assessments. NERC's 2025 Summer Reliability Assessment includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota in the "WECC-Rocky Mountain" region, and includes Arizona and New Mexico, most of Nevada, and small parts of California and Texas in the "WECC-Southwest" region.[146] The regional grouping used in the Report is arbitrary and inconsistent with these existing groupings.

The Report states its model is derived from NERC's Interregional Transfer Capability Study ("ITCS")[147] and asserts the subregions used in the Report, called Transmission Planning Regions ("TPRs"), "match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions."[148] However, the ITCS makes clear that FERC's transmission planning regions were altered to create the TPRs for the ITCS,[149] which was focused on transfer capability between neighboring regions and not resource adequacy. [150] The ITCS Final Report does not explain how specific footprints were determined in any detail.[151] In January 2025 comments filed with FERC in response to the ITCS report, DOE commented "[t]he subregion boundaries used in the ITCS are useful for evaluating interregional transfer capability given the chosen methodology, *but not for evaluating resource adequacy of those subregions*."[152] DOE explained the ITCS subregions do not reflect actual monitored transmission constraints, nor

[143] Report at 27 & Tbl. 8.
[144] Report at 9, 27 Tbl. 8. *See also* Ex. C, IPI Report at 20.
[145] Report at vi.
[146] NERC, *2025 Summer Reliability Assessment* at 36, 38 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.
[147] Report at 2.
[148] Report at 10 n.14.
[149] Ex. A, NERC ITCS Report at 7.
[150] Fiscal Responsibility Act of 2023, H.R. 3746, 118th Congress (2023–2024) (directing NERC to study the total transfer capability between transmission planning regions).
[151] *See* Ex. A, NERC ITCS Report at 7.
[152] Comments of the U.S. Dep't of Energy, FERC Docket No. AD25-4-000, at 6 (Jan. 17, 2025) (emphasis added).

do they accurately capture the service territories or balancing authority areas that are the footprints on which resource adequacy decisions are made.[153]

Despite DOE's earlier comments, the DOE Report fails to explain why the TPR subregions, many of which have no similarities to the regions actually used by NERC to assess reliability nor the planning regions used by entities with resource adequacy obligations, are now appropriate geographic boundaries for running resource adequacy scenarios and guiding reliability interventions. Returning to the example of the Front Range region, neither the ITCS Final Report nor the DOE Report explain why resource adequacy analysis should be done collectively for Colorado and portions of New Mexico and Wyoming, in which the load serving entities and balancing authorities plan their systems, acquire generating resources, and decide to interconnect to neighboring systems under completely separate processes. Because many of the Report's subregions are divorced from how the grid is actually planned and operated, they risk inaccurate groupings of load and available generating resources and incomplete understandings of how transmission capacity may be used in times of peak demand.

The Report suffers from other analytical shortcomings, which are amply described in the Institute for Policy Integrity's report and are expressly incorporated and adopted here.[154] As the Institute for Policy Integrity explained, DOE fails to offer a reasonable explanation for its choice of resource adequacy metrics and targets, outage thresholds, or the use of a deterministic model instead of a more accurate probabilistic model. By relying solely on weather data from recent years in a deterministic model, rather than a more statistically accurate probabilistic model, the Report "does not sufficiently account for uncertainty," weakening the strength of its modeled findings for 2030.[155]

Given the abundant shortcomings in DOE's methodology, it is unreasonable to rely on the data and analysis contained in the Report to draw any firm conclusions about the resource adequacy of any region of the United States electrical grid now or in 2030, and DOE's various findings of resource inadequacy despite these flaws is arbitrary and capricious.

iv. DOE's flawed analysis establishes an arbitrary and unlawful preference for fossil fuel plants over other methods to preserve grid reliability, contrary to the Federal Power Act.

The flawed assumptions discussed above lead to an obvious conclusion: that DOE designed the Report to satisfy the White House's goal of bailing out uneconomic and environmentally harmful power plants. DOE's report is not addressing an emergency, but seeking to prop up a coal industry that is unable to compete with cheaper and cleaner modern energy sources like wind, solar, and batteries.

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[153] *See id.* at 6-7.
[154] See Ex. C, IPI Report at 18-26
[155] *Id*. at 21.

Executive Order 14262 was signed alongside EO 14261 *Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241*. EO 14261 claims to "encourage and support our Nation's coal industry to increase our energy supply, lower electricity costs, stabilize our grid, create high-paying jobs, support burgeoning industries, and assist our allies." And President Trump's statements at the signing ceremony make clear that the two orders are intended to serve a complementary purpose. As the President said, with coal workers lining the stage behind him for a photo-op, "we're bringing back an industry that was abandoned" and "all those plants that have been closed are going to be opened."[156]

The President's Grid Reliability Order references his earlier Declaration of an Energy Emergency, *see* EO 14156 "Declaring a National Energy Emergency," which created an energy emergency based on an alleged shortage of affordable and domestic energy sources. In all orders, the President narrowly focuses on fossil fuels and specifically excludes wind, solar, or batteries from the definition of "energy." And the Administration has simultaneously taken steps to derail the wind and solar industries, revoking previously issued permits for offshore wind projects, pausing the issuance of approvals, permits, and loans for wind projects nationwide, and adding bureaucratic hurdles to the permitting process for wind and solar.[157]

To the extent that the Report advances the Administration's policy of discriminating against renewable energy, batteries, and transmission to advance the extra-statutory motive of preserving aging fossil fuel power plants at consumer expense, it is contrary to express goals of the Federal Power Act.[158] Sections 205 and 206 of the Federal Power Act require rates to be just and reasonable and not unduly discriminatory or preferential.[159] Purporting to justify Section 202(c) orders for fossil fuel plants that are not needed and ignoring other viable methods to preserve grid reliability at a lower cost for consumers is likely to result in unjust and unreasonable rates. While 202(c) permits deferral of this issue to FERC in a rate proceeding, DOE must – at minimum – consider how a streamlined and uniform methodology may impact rates and cost recovery.

Significantly, when DOE proposed in 2017 that FERC adjust its rates to compensate generation that could store 90 days of fuel on-site (i.e., coal and nuclear generation), FERC unanimously rejected that proposal.[160] FERC concluded that DOE failed to demonstrate that allowing all eligible resources to receive a special rate regardless of the specific reliability needs of that region would be a just and reasonable outcome.[161] DOE also failed to show that such a remedy "would not be unduly discriminatory or preferential" since only "certain resources [could] be eligible for the rate, thereby excluding other resources that may have resilience

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[156] Adam Burke, *Trump orders coal revival, but market favors natural gas*, NPR (April 17, 2025) https://www.npr.org/2025/04/16/nx-s1-5359013/trump-orders-coal-revival-market-favors-natural-gas.
[157] *See generally*, Complaint, New York, et al. v. Trump, et al., No. 25-cv-11221 (D. Mass., filed May 5, 2025) (describing Administration's assault on wind energy). *See also e.g.,* Department of the Interior, Secretarial Order 3437, https://www.doi.gov/document-library/secretary-order/so-3437-ending-preferential-treatment-unreliable-foreign; Department of the Interior, Secretarial Order 3438, https://www.doi.gov/document-library/secretary-order/so-3438-managing-federal-energy-resources-and-protecting.
[158] *See* FPA Sections 205 and 206; 16 U.S.C. §§ 824d, 824e.
[159] *Id*.
[160] *See* Order Terminating Rulemaking, 162 FERC ¶ 61,012, ¶ 16 (Jan. 8, 2018).
[161] *Id*.

attributes."[162] DOE's second attempt to manipulate the energy markets in favor of its preferred energy sources suffers from the same fatal flaws and its motives are contrary to the goals of the Federal Power Act.

b. The Report does not describe an "emergency" and cannot be used to justify future grid reliability interventions by DOE.

i. Common usage and regulation define "emergency" narrowly.

Section 202(c) is limited, by its own terms, to either "the continuance of any war in which the United States is engaged," or "whenever the Commission determines that an emergency exists *by reason of*" certain enumerated causes.[163] Those causes include: (1) "a *sudden* increase in the demand for electric energy," (2) "a shortage of electric energy or of facilities for the generation or transmission of electric energy," (3) a shortage of "fuel or water for generating facilities," and (4) "other causes."[164]

The relevant focus is therefore on the definition of "emergency." In 1930, just a few years before the Act's passage, Webster's New International Dictionary of the English Language defined "emergency" as a "sudden or unexpected appearance or occurrence… an unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency." The year before the statute was last amended, Merriam-Webster's Dictionary and Thesaurus (2014) defined "emergency" as "an *unforeseen* event or condition requiring prompt action." Thus, at all relevant times "emergency" was defined as being unexpected or unforeseen and requiring some form of exigent response.

That limited reading of Section 202(c) is bolstered by the emergency provision's immediate statutory context. Section 202(c) is preceded by Section 202(b), which grants what is now the Federal Energy Regulatory Commission the authority to issue similar interconnection orders "*after* opportunity for hearing," indicating that Congress intended to place a temporal constraint upon the emergency authority in Section 202(c), limiting it to situations not amenable to public notice and hearing.[165]

DOE's regulations implementing Section 202(c) also suggest the provision's narrow applicability to only true emergencies. [166] DOE has provided that "actions under this authority are envisioned as meeting a specific inadequate power supply situation."[167] The regulations

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[162] *Id*.
[163] 16 U.S.C. § 824a(c)(1) (emphasis added).
[164] *Id.* (emphasis added). The catchall "other causes" must still be the "reason" that an emergency exists. *Id*. *See also* Rolsma, *The New Reliability Override,* 57 U. Conn. L. Rev. at 810-13.
[165] 16 U.S.C. § 824a(b); 42 U.S.C. § 7172(a)(1)(B).
[166] *See also* 46 Fed. Reg. 39987 (Aug. 6, 1981).
[167] 10 C.F.R. § 205.371.

further define applicable emergencies to include "an *unexpected* inadequate supply of electric energy," "*unforeseen* occurrences," or "a *sudden* increase in customer demand," echoing the.[168]

In guidelines for defining "inadequate utility system fuel inventory or energy supply," the regulations further specify that the threshold for such an emergency may be met "when, combined with other conditions, the projected energy deficiency upon the applicant's system *without emergency action by the DOE*, will equal or exceed 10 percent of the applicant's then normal daily net energy for load, or will cause the applicant to be unable to meet its normal peak load requirements *based upon use of all of its otherwise available resources* so that it is unable to supply adequate electric service to its ultimate customers."[169] This definition again narrows the circumstances in which DOE may exercise its 202(c) authority to those not redressable by other means, implicating only acute or imminent power shortages where no other recourse is available.[170]

ii. The report does not point to any sudden or unforeseen circumstances.

. DOE's report does not identify any region, except ERCOT, that currently fails to meet DOE's reliability targets.[171] DOE's flawed analysis points to a failure to meet reliability targets only in 2030. An expected increase in demand that can be projected over the next five years is not an energy emergency. Those shortfalls are not "unexpected" or "imminent" so as to justify a departure from normal planning procedures. The Report is squarely focused on 2030 and does not assess resource adequacy in any of the intervening years. According to the standard set out in *Otter Tail Power Co. v. Federal Power Com.*, 429 F.2d 232, 234 (8th Cir. 1970), the shortfalls predicted by the Report are at best policy crises "which [are] likely to develop in the foreseeable future but which [do] not necessitate immediate action." In other words, the concerns may be addressable using FPA § 202(b), but certainly not FPA § 202(c).

Significantly, DOE has never before issued a 202(c) order based on such a broad and speculative increase in load demand. On the contrary, prior to 2025, DOE had only used 202(c) to delay the retirement of generation facilities on three narrow occasions, as requested by the system operator or government body, and only for as long as necessary to address the imminent emergency.[172]

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[168] *Id.* (emphasis added).
[169] 10 C.F.R. § 205.375 (emphasis added).
[170] While the regulations also state that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency … ," the definition crucially does not allow for *projections* of such circumstances to qualify or include any qualifying terms indicating similar intent. On the face of the regulation, and consistent with reasonable interpretations of the statute, such an eligible power shortage must be sufficiently imminent to avoid reducing the inherent limitation of the word "emergency" to an absurdity. 10 C.F.R.§ 205.371.
[171] Report at 7.
[172] *See* Benjamin Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. 789, 843-46 (2025).

iii. Reliance on the Report to justify a Section 202(c) order would be contrary to law.

Based on EO 14262 and DOE's own statements, it is evident that the Department intends to rely upon the analysis and methodology in the Report to justify future Section 202(c) orders.[173] But the Report cannot lawfully be relied upon to justify the exercise of DOE's limited emergency authority. Doing so would be contrary to law.[174]

As discussed above, the Secretary of Energy's authority under Section 202(c) of the Federal Power Act is statutorily limited to wartime or certain "emergency" situations; otherwise, similar proceedings fall under the jurisdiction of the Federal Energy Regulatory Commission through a process of notice and hearing.[175] Even taking the Report at face value, its own conclusions fail to describe anything resembling an emergency in any part of the country besides ERCOT.[176] Any conclusion that an emergency exists is undermined by the arbitrary nature of the Report's analysis.[177]

Moreover, the Report's conclusions, on their face, fail to describe an "emergency". Conclusions about resource adequacy five years in the future, in 2030, fall outside of the temporal limits of an "emergency" and are exactly the type of concern that should be dealt with through usual planning processes.[178] Any attempt by DOE to bootstrap future Section 202(c) orders to the Report would be in direct contradiction to its statutory authority to issue such orders and its own regulations implementing that authority.[179]

c. DOE failed to consider an important aspect of the problem: existing reliability mechanisms.

Agency action is arbitrary and capricious under the APA if it "fails to consider an important aspect of the problem." *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). Here, DOE has acted as if the Report exists on a blank slate of resource adequacy and reliability planning yet that could not be farther from the

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[173] *See* Report at vi; EO 14262 Sec. 3(c). In at least one Section 202(c) order issued after the publication of EO 14262 but before the release of the Report, the Department stated that it "plans to use this methodology to further evaluate" the generation units subject to that order. Order No. 202-25-4 ("Eddystone 202(c) Order") at 2 (May 30, 2025).

[174] *See* 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.370-371, 375.

[175] 16 U.S.C. §§ 824a(b)-(c); 42 U.S.C. §§ 7151(b), 7172(a)(1)(B).

[176] Report at 7 ("Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average load loss per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study."); *see also* Ex. C, IPI Report at 29-31 ("Despite DOE's press statement asserting that the study's methodology can help guide [sic] 'guide Federal reliability interventions,' presumably to address the EO's [EO 14262] mandate that DOE find a way to routinize further 202(c) emergency orders, the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy." (footnotes omitted)).

[177] *See supra* Section 4.a.

[178] *See* Report at 8-9.

[179] 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.370-371, 375.

truth. As described above, a multilayered system of resource planning involving states and regional grid operators ensures adequate supplies and grid stability.[180]

The Report's conclusion that "absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens," is undermined by this failure.[181] States across the nation are grappling with how to meet increased demand from AI data centers while maintaining grid reliability and distributing the costs of those changes in an equitable manner. Without an analysis of the existing framework for making such determinations, and ongoing efforts to adjust those systems to meet new challenges, there is no basis for DOE's conclusion that "intervention" – likely through 202(c) orders – is the only way to possibly reach those goals.[182]

d. As described in the EO, the report intrudes upon state authority.

EO 14262 directs the Secretary of Energy to rely upon the methodology disclosed in the Report to "identify current and anticipated regions with reserve margins below acceptable thresholds" and "identify which generation resources within a region are critical to system reliability."[183] The Executive Order also directs DOE to further develop a "protocol" for applying this analysis to "include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource."[184] The Report is therefore foundational to the "protocol" that EO 14262 intends will direct emergency orders to override planned retirements. The Report thus directly intrudes on the States' lawful resource adequacy planning processes.

With respect to regulatory oversight for resource adequacy, section 201 of FPA, 16 U.S.C § 824(b)(1), reserves authority over generation facilities to the states. It states in pertinent part: "The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over facilities used for the generation of electric energy* or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[185]

The Federal Power Act is likewise clear that federal regulatory jurisdiction over the power sector "extend[s] only to those matters which are not subject to regulation by the States."[186] With the few and specific exceptions outlined elsewhere in the statute, this jurisdiction

[180] *See Supra,* Section 2.a.
[181] Report at 1.
[182] *Id*.
[183] Executive Order 14262, §§ 3(b)-(c).
[184] *Id.* at § 3(c).
[185] *Id*. (emphasis added).
[186] 16 U.S.C. § 824(a).

does *not* extend to "facilities used for the generation of electric energy … ."[187] This statutory language places the regulation of generation resource adequacy squarely in the ambit of the states, not the federal government.[188]

States have typically exercised this authority through a combination of individual state legislative and regulatory functions as well as engaging in multistate RTOs and ISOs. Some states have retained this authority over resource adequacy in its entirety,[189] while others have directed their utilities to join RTOS/ISOs that, through their tariffs, impose resource adequacy requirements. Those RTO/ISOs also generally establish markets that allow market participants to buy and sell capacity and thereby to facilitate market entry and exit decisions based on price signals. Resource adequacy requirements in RTO/ISO tariffs have been held to be practices affecting wholesale rates subject to the jurisdiction of FERC under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d & 824e.[190]

Through these channels, states conduct the careful, calculated, long-term capacity planning that goes ignored in DOE's Report.[191] The Report utterly fails to recognize or properly account for the states' traditional and statutory role in resource adequacy planning, and as forecasted by EO 14262, the Report constitutes a central component of the federal government's proposed protocol to usurp the states' authority over this issue.

The use of emergency orders to illegally override state resource adequacy planning has been challenged on the same grounds by the Organization of MISO States, Inc. (OMS), in its Petition for Rehearing of DOE Order No. 202-25-3 (ordering continued operation of the J.H. Campbell coal-fired power plant). In its Petition, OMS noted among other points that "[t]his is the first time the DOE has invoked Section 202(c) outside a severe weather event or emergency, and for the first time, uses the power to suspend a retirement and interfere with established and vetted state and regional planning processes."[192] OMS' petition continues, "[t]his expansive use of emergency powers sets a troubling precedent, enabling interventions in routine, state-approved planning decisions without an actual crisis and risks establishing its use to circumvent normal utility, RTO, and states processes, and likely exposes ratepayers to costs that should not be borne."[193] In DOE's issuance of the Report pursuant to EO 14262, the federal government is

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[187] *Id.* § 824(b)(1).
[188] *See, e.g.*, Ashley J. Lawson, CONG. RESEARCH SERV., R47521, *Electricity: Overview and Issues for Congress*, at 7 (Feb. 14, 2025).
[189] *See Devon Power LLC et al.,* 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").
[190] *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).
[191] *E.g.*, Report at 2-3, 5, 12-13 (relying solely on federal, EIA, and NERC estimates and failing to mention nuanced state, RTO, or ISO figures and actions).
[192] *See* Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Order No. 202-25-3 (filed June 23, 2025), https://www.energy.gov/sites/default/files/2025-07/Petition%20to%20Intervene%20and%20Request%20for%20Rehearing%20of%20the%20Organization%20of%20MISO%20States.pdf.
[193] *See id*. at 5; *see also id.* at 4 (challenging "Violation of the Federal Power Act and State Jurisdiction.").

attempting to establish its own rule for resource adequacy planning from which it can routinely issue illegal orders under the same flawed premise that OMS challenges in its Petition.

Lastly, Section 202(c) does not serve as a widespread grant of DOE jurisdiction over resource adequacy and capacity planning. "Congress … does not … hide elephants in mouseholes."[194] First, as described above in Part [3b], Congress assigned non-emergent questions of interconnection and transmission necessity amenable to public notice and hearing to FERC, not DOE.[195] Moreover, even this authority should not be seen as a substitute for the overarching reservation of regulatory jurisdiction over resource adequacy planning to the states.[196] No reasonable reading of the relevant statutory authorities could construe DOE's authority in 16 U.S.C. § 824a(c) as intruding on the explicit and traditional role of the states in regulating electricity generation and resource adequacy. However, all available indicators in the Report and EO 14262 evince a flawed understanding contrary to DOE's appropriate and limited role in this space, thus the Department should reconsider its findings and position on this authority.

e. DOE's Failure to Provide Public Notice and Comment on its New Standard and Methodology Violated the Administrative Procedure Act, 5 U.S.C. § 553.

Before adopting a final rule, the Administrative Procedure Act requires agencies to publish in the Federal Register a notice of proposed rulemaking and accept public comment.[197] An agency action that imposes legally binding obligations or prohibitions on regulated parties, substantially removes the agency's discretion, or would be the basis for an enforcement action for violations of those requirements, is a legislative rule that requires notice and comment.[198] Notice and comment is also required when agencies establish new standards that are not derived from an existing statute or regulation or when an agency relies on its statutorily delegated authority to establish policy.[199] Additionally, agency documents that adopt a "new position inconsistent with any of the [agency's] existing regulations" are subject to notice and comment.[200]

DOE's report creates a brand-new national standard and methodology for evaluating resource adequacy. This standard has concrete legal effects because DOE plans to enforce it via Section 202(c) emergency orders. It also is inconsistent with DOE's existing regulations, which direct DOE to issue emergency orders in very different circumstances based on different criteria than what DOE now proposes. Significantly, DOE acknowledges that its conclusions lack sufficient input from the entities responsible for operating the grid, but DOE nonetheless refused to submit the Report to notice and comment where the public could have tested DOE's assumptions and conclusions. Assuming DOE continues to comply with the Executive Order's

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[194] *Whitman v. Am. Trucking Ass'ns, Inc.*, 531 U.S. 457, 468 (2001).
[195] 16 U.S.C. § 824a(b); 42 U.S.C. § 7172(a)(1)(B).
[196] 16 U.S.C. §§ 824(a)-(b).
[197] 5 U.S.C. § 553(b)-(c).
[198] *See Nat'l Min. Ass'n v. McCarthy*, 758 F.3d 243, 251–52 (D.C. Cir. 2014).
[199] *See Children's Hosp. of the King's Daughters, Inc. v. Azar*, 896 F.3d 615, 622 (4th Cir. 2018).
[200] *Shalala v. Guernsey Mem'l Hosp.*, 514 U.S. 87, 99–100 (1995).

unlawful command to use this Report to support future Section 202(c) orders, the Report and any action relying on it must be set aside for failure to provide notice and comment.

i. DOE's standard is an exercise of assumed legislative authority, and it has concrete legal effects.

Pursuant to the Executive Order, DOE established a "uniform methodology" for assessing resource adequacy across the country.[201] That methodology adopts a new "resource adequacy standard" to measure the desired level of adequacy needed for the bulk power system.[202] DOE acknowledges that it is not using the "traditional . . . criterion" for measuring resource adequacy and is relying on metrics that are "not standardized in the U.S. today."[203] Instead, DOE unilaterally adopts new metrics to evaluate resource adequacy and establishes the reliability targets that should be obtained.[204] DOE's choice of metrics and the targets to be achieved are value judgments and should be informed by economic tradeoffs and other policy considerations about what level of system reliability should be achieved and at what cost to consumers, areas where public input is essential to sound decision making.[205]

DOE also fills its methodology with value-laden policy choices around the data inputs and assumptions that determine when DOE's reliability standard is achieved. As just one example, DOE includes projected future demand from potential new AI data centers as part of its calculation of future load.[206] Those data centers have not yet been built and some may never be.[207] And, as DOE recognized, grid operators are not likely to allow those large loads to connect if doing so threatens reliability.[208] Including those potential loads in DOE's determinations of system reliability thus inherently represents a policy choice: Should present-day consumers pay to keep retiring power plants online to ensure that potential data centers can be reliably served in the future?[209]

Even assuming *arguendo* that DOE has the statutory authority to set a uniform reliability standard, place risks of future large load growth on current consumers, or engage in long-term resource adequacy planning for the entire nation, it still must involve stakeholders through notice and comment in those legislative choices. "When an agency relies on expressly delegated authority to establish policy . . . courts generally treat the agency action as legislative [] rulemaking" and require notice and comment.[210] In other words, "when Congress leaves [] a policy choice to the agency, [courts] should lean toward finding that the agency's making of that

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[201] *See* Report at *vi* (explaining that the report is "delivering the required uniform methodology to identify at-risk region(s)"); Executive Order 14262 § 3(b).
[202] Report at 3.
[203] *Id*. 3-4.
[204] *See id*.
[205] *See* Ex. C, IPI Report at ii (criticizing DOE's choice of targets as not "appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences").
[206] *See* Report at 1-3.
[207] *See, e.g*., Ex. E, London Economics International Report; Laila Kearney and Liz Hampton, *U.S. Power Stocks Plummet as DeepSeek Raises Data Center Demand Doubts*, Reuters (Jan. 27, 2025) https://www.reuters.com/business/energy/us-power-stocks-plummet-deepseek-raises-data-center-demand-doubts-2025-01-27/.
[208] *See* Report at 14.
[209] *See also supra* Section 4.a. (discussing other arbitrary assumptions in DOE's analysis).
[210] *Children's Hosp. of the King's Daughters, Inc.*, 896 F.3d at 622.

choice requires notice and comment.[211] "Otherwise, it would be difficult to imagine what regulations *would* require notice and comment procedures."[212]

DOE's standard also has concrete legal effects because, consistent with the Executive Order, DOE will use Section 202(c) emergency orders (or the threat of Section 202(c) orders) to ensure regions meet the new standard. The Executive Order directs DOE to use this standard to "establish . . . a protocol" to identify generation resources that are critical to system reliability.[213] DOE's "protocol shall additionally" use Section 202(c) of the Federal Power Act to "ensure" those resources are retained and prevent their retirement.[214] "Protocol" means "a set of rules to be followed . . ."[215] As DOE has made clear, DOE "plans to use" this new standard to evaluate retiring coal plants and potentially issue Section 202(c) emergency orders preventing their retirement.[216]

DOE's new standard, and protocol for enforcing it, removes DOE's discretion and is intended to provide the basis for enforcement actions via Section 202(c) orders.[217] The new standard is not derived from the Federal Power Act or, as explained further below, from DOE's existing regulations, but is an entirely new method of determining resource adequacy across the country. DOE must accordingly submit its new standard and methodology to public notice and comment.[218]

ii. DOE must provide notice and comment because its standard allegedly supports issuing emergency orders based on factors that conflict with existing regulations.

DOE's Report provides new bases for issuing emergency orders that conflict with DOE's existing regulations, but DOE cannot amend those standards without first providing notice and comment.[219] DOE promulgated regulations detailing how and when it issues Section 202(c) emergency orders following public notice and comment in 1981.[220] Under DOE's current regulations, emergency orders "are envisioned as meeting a *specific* inadequate power supply situation," occasioned by "acts of God[] or unforeseen occurrences not reasonably within the

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[211] *Id*.
[212] *Id*. (quoting *N.H. Hosp. Ass'n v. Azar*, 887 F.3d 62, 70–71 (1st Cir. 2018)).
[213] Executive Order 14262 at § 3(c).
[214] *Id*.
[215] PROTOCOL, Black's Law Dictionary (12th ed. 2024).
[216] Order No. 202-25-4 at 2 (Eddystone Order). *See also* U.S. DEP'T OF ENERGY, *Fact Sheet: The Department of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [https://perma.cc/YLX7-8G7T] (explaining that DOE's methodology will be used, pursuant to the executive order, "prevent [] generation resources from leaving the bulk-power system"); Press Release, U.S. Dep't of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security [https://perma.cc/8TEJ-AGH6]. (stating that its "methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act"); Report at *vi* (explaining that DOE's standard will be used to "guide reliability interventions"), 1 (emphasizing the need for DOE's "decisive intervention" in energy markets), 10 (analyzing ERCOT because "FPA Section 202(c) allows DOE to issue emergency orders to ERCOT").
[217] *See Nat'l Min. Ass'n v. McCarthy*, 758 F.3d 243, 251–52 (D.C. Cir. 2014).
[218] *See id*.; *Children's Hosp. of the King's Daughters, Inc. v. Azar*, 896 F.3d 615, 622 (4th Cir. 2018).
[219] *See Shalala*, 514 U.S. at 99–100.
[220] *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39,984 - 39,989 (Aug. 6, 1981).

power of the affected 'entity' to prevent."[221] DOE did not intend its emergency authority to replace long-term planning by utilities: "while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself."[222]

As DOE stated then, "[t]he factors that DOE will consider in determining whether an emergency exists are specified in § 205.373."[223] Section 205.373 requires applicants to submit detailed information on "daily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the emergency" and make a "showing that adequate electric service cannot be maintained without additional power transfers." Applicants must also describe what "conservation or load reduction actions have been implemented" before seeking emergency relief.[224] In sum, DOE's current regulations direct a case-by-case analysis of specific, temporary shortages in particular situations, based on detailed information from an applicant.

DOE's new standard and methodology is an unprecedent expansion of the bases upon which DOE will justify Section 202(c) emergency orders, but DOE has not offered public comment on that expansion. Rather than focusing on specific showings of an imminent threat to grid stability, the report rests on DOE's analysis of "the U.S. electric grid's ability to meet future demand through 2030."[225] Rather than consider the "daily peak load and energy requirements of the past 30 days and projections for each day of the [] emergency," 10 C.F.R. § 205.373, DOE now plans to base Section 202(c) decisions on speculation over the development of artificial intelligence, re-industrialization of the U.S. economy, and other uncertain developments over the next five years.[226] Rather than consider the "scheduled . . . deliveries" during the emergency period and needs of existing firm customers, § 205.373(d),(f), DOE now proposes to find an emergency based on potential load growth for customers who do not currently, and may never, exist.[227]

Rather than allowing utilities and grid operators to solve long-term planning issues themselves, DOE now seeks to intervene in those state- and FERC-regulated processes based on its own assumptions about future load growth and electricity supply. But unlike DOE's Report, the long-term resource adequacy plans developed by utilities and grid operators are transparent and publicly-accountable processes that involve relevant stakeholders and the public.[228] DOE, on the other hand, published its analysis without critical data or insights from the entities who actually operate and maintain the electric grid.[229]

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[221] 10 C.F.R. § 205.371 (emphasis added).
[222] 46 Fed. Reg. at 39,985; *see also* 10 C.F.R. § 205.371
[223] 46 Fed. Reg. at 39,985.
[224] *Id*.; *see also* 10 C.F.R. § 205.375 (defining an inadequate energy supply as when an applicant is "unable to meet its normal peak load requirements based upon use of all its otherwise available resources.").
[225] Report at 2.
[226] Report at 2; *see also supra* Section 4.a.
[227] *See, e.g*., Ex. E London Economics International Report; Laila Kearney and Liz Hampton, *U.S. Power Stocks Plummet as DeepSeek Raises Data Center Demand Doubts*, Reuters (Jan. 27, 2025) https://www.reuters.com/business/energy/us-power-stocks-plummet-deepseek-raises-data-center-demand-doubts-2025-01-27/.
[228] *See supra* Section 2.a.
[229] Report at *i.*

Rather than considering what other "conservation or load reduction actions have been implemented" before turning to emergency relief, 10 C.F.R. § 205.373, DOE's standard ignores those possibilities altogether. Instead, DOE adopts aggressive and likely overstated assumptions of load growth and ignores whether any of that future demand could be flexibly integrated into the grid, what measures state and local regulators are taking to mitigate the impact of new data center demand on grid reliability, or other factors influencing grid reliability over the long-term.[230] DOE appears to admit that its overstated potential load growth will not *actually* lead to any grid reliability emergency, as there is no "indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system."[231]

DOE appropriately involved the public when it initially set out the process and factors to consider for Section 202(c) orders in its 1981 rulemaking. Yet now, DOE seeks to expand the bases for Section 202(c) orders in ways that intrude on state-regulated processes and the free market, without any input from stakeholders or the public who will ultimately pay for DOE's actions. Because the methodology and protocol effectively "expand[s] the footprint [of DOE's emergency authority] by imposing new requirements, rather than simply interpreting the legal norms Congress or the agency itself has previously created" and is inconsistent with DOE's existing regulations, it is a "rule" under the APA and notice and comment is required.[232]

iii. DOE acknowledges the importance of involving the States and other actors yet fails to provide public notice and comment to test DOE's assumptions and conclusions.

DOE's failure to provide public notice and comment is prejudicial error. DOE admittedly lacks the "range of data and insights" to make robust reliability decisions that entities responsible for the maintenance and operation of the grid have access to.[233] Had the States been given adequate notice and an opportunity to comment, they could have provided more information to DOE on how existing mechanisms address grid reliability, issues with DOE's assumptions, chosen metrics, and choice of data, identified gaps in DOE's analysis and data, and other issues. Numerous grid experts have commented on shortfalls with DOE's report.[234] Given adequate notice and an opportunity to comment, the States could have obtained their own expert analysis and potentially raised even more issues with DOE's proposed standard and methodology than what time permitted the States to raise here.

DOE has previously acknowledged the importance of involving States and the public in these questions. When DOE initially established regulations governing how and when it would

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[230] *See, e.g.*, Ex. D, Nicholas Institute Report; Jason Plautz, *State lawmakers grapple with energy demand for data centers*, E&E News (Mar. 3, 2025) https://www.eenews.net/articles/state-lawmakers-grapple-with-energy-demand-for-data-centers/; Washington Office of the Governor, *Gov. Bob Ferguson Signs Executive Order Establishing a Data Center Workgroup* (Feb. 4, 2025) https://governor.wa.gov/news/2025/governor-bob-ferguson-signs-executive-order-establishing-data-center-workgroup.

[231] Report at 14.

[232] *Children's Health Care v. Centers for Medicare & Medicaid Servs.*, 900 F.3d 1022, 1025 (8th Cir. 2018); *see also Shalala*, 514 U.S. at 99–100.

[233] Report at *i*

[234] *See, e.g.*, Jeff St. John, *Critics fear Trump will use flawed DOE report to push pro-coal agenda*, Canary Media (July 14, 2025), https://www.canarymedia.com/articles/fossil-fuels/trump-doe-report-open-coal-plants; Matthias Fripp and Brendan Pierpont, Opinion, *Energy Department's flawed grid study props up expensive, zombie power plants*, UtilityDive, https://www.utilitydive.com/news/doe-grid-reliability-study-zombie-power-plants/753596/.

issue emergency orders, DOE consulted with the Federal Energy Regulatory Commission and state officials.[235] DOE also explained that "[t]he DOE intends to utilize any available State and local expertise in resolving an emergency."[236] Indeed, DOE's organizational statute *requires* it to consult with States "[w]henever any proposed action by the Department conflicts with the energy plan of any State."[237] And States are already taking actions to address reliability issues and load growth in their jurisdictions.[238] DOE's refusal to collaborate with States or meaningfully involve other stakeholders here is inexplicable, conflicts with DOE's organizational statute, and the APA.

V. Conclusion

The State's request for rehearing should be granted and DOE should withdraw or otherwise amend the subject Report following public vetting through notice and comment proceedings. In the meantime, DOE cannot rely on the challenged report to support the exercise of its 202(c) authority. Doing so would be arbitrary and capricious and otherwise contrary to law and impose significant harm on our States.

Filed: August 6, 2025

[235] 46 Fed. Reg. at 39,985.
[236] *Id*.
[237] 42 U.S.C. § 7113; *see also* 16 U.S. Code § 824h (encouraging federal-state collaboration).
[238] Jason Plautz, *State lawmakers grapple with energy demand for data centers*, E&E News (Mar. 3, 2025) https://www.eenews.net/articles/state-lawmakers-grapple-with-energy-demand-for-data-centers/; Washington Office of the Governor, *Gov. Bob Ferguson Signs Executive Order Establishing a Data Center Workgroup* (Feb. 4, 2025) https://governor.wa.gov/news/2025/governor-bob-ferguson-signs-executive-order-establishing-data-center-workgroup.

Respectfully Submitted,

ANTHONY G. BROWN
ATTORNEY GENERAL OF MARYLAND

/s/ Steven J. Goldstein
Steven J. Goldstein
Robert N. Brewer
Assistant Attorneys General
Office of the Attorney General of Maryland
200 Saint Paul Place, 20th Floor
Baltimore, MD 21202
410-576-6414
sgoldstein@oag.state.md.us

NICHOLAS W. BROWN
ATTORNEY GENERAL OF
WASHINGTON

s/ Megan Sallomi
Megan Sallomi
Assistant Attorney General
Environmental Protection Division
800 5th Ave. Suite 2000
Seattle, WA 98104
(206) 389-2437
Megan.sallomi@atg.wa.gov

KWAME RAOUL
ATTORNEY GENERAL OF ILLINOIS

/s/ Jason E. James
Jason E. James
Assistant Attorney General
Illinois Attorney General's Office
201 W. Pointe Drive, Suite 7
Belleville, IL 62226
Phone: (217) 843-0322
Email: jason.james@ilag.gov

DANA NESSEL
ATTORNEY GENERAL OF MICHIGAN

/s/ Michael E. Moody
Michael E. Moody (P51985)
Lucas Wollenzien (P86928)
Assistant Attorneys General
Special Litigation Division
P.O. Box 30755
Lansing, MI 48909
517-335-7627
MoodyM2@michigan.gov
WollenzienL@michigan.gov

Christopher M. Bzdok (P53094)
Special Assistant Attorney General
chris@tropospherelegal.com

KEITH ELLISON
ATTORNEY GENERAL OF MINNESOTA

/s/ Alyssa Bixby-Lawson
Alyssa Bixby-Lawson
Special Assistant Attorney General
Attorney Reg. No. 0397193
Minnesota Office of the Attorney General
445 Minnesota Street, Suite 600
St. Paul, Minnesota 55101-2131
(651) 300-0904 (Voice)
(651) 297-4139 (Fax)
Alyssa.bixby-lawson@ag.state.mn.us

KRIS MAYES
ATTORNEY GENERAL OF ARIZONA

/s/ Kirsten Engel
Kirsten Engel
Special Attorney General
Environmental Protection Unit
2005 N. Central Ave
Phoenix, AZ 85085
(520) 209-4020
Kirsten.Engel@azag.gov

WILLIAM TONG
ATTORNEY GENERAL OF CONNECTICUT

/s/ Jill Lacedonia
Jill Lacedonia
Assistant Attorney General
165 Capitol Avenue
Hartford, CT 06106
(860) 808-5250
Jill.Lacedonia@ct.gov

PHILIP J. WEISER
ATTORNEY GENERAL OF COLORADO

/s/ Carrie Noteboom
Carrie Noteboom
Assistant Deputy Attorney General
Jessica Lowrey
First Assistant Attorney General
Ralph L. Carr Judicial Center
Colorado Department of Law
1300 Broadway, 10th Floor
Denver, CO 80203
(720) 508-6285
carrie.noteboom@coag.gov
jessica.lowrey@coag.gov

LETITIA JAMES
ATTORNEY GENERAL OF NEW YORK

/s/ Morgan Costello
Morgan Costello
Chief, Affirmative Litigation Section
Ashley M. Gregor
Assistant Attorney General
Environmental Protection Bureau
NYS Office of the Attorney General
The Capitol
Albany, NY 12224
(518) 776-2392
morgan.costello@ag.ny.gov
ashley.gregor@ag.ny.gov