BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 141

MISO 2025-26 Winter Readiness Presentation

2025-26 Winter Readiness Workshop

October 29, 2025

Agenda

Welcome – Jason Howard

Assessments

1. Weather (Adam Simkowski/Ella Dankanics)
2. Generation (Gurmanpreet Kaur)
3. Transmission (Fisseha Zewdu)
4. Winterization Survey Results (Mike Mattox)

Seasonal Risk / Uncertainty Management

1. Lessons Learned Winter 2024-25 (Jason Howard)
2. Dynamic Ramp Changes (Matt Campbell)

Emergency Procedures /Training

1. Technical Development (Anita Hurst)
2. EOP-002 Updates (Don Hunter)

Q&A

2025-26 Winter Readiness: Weather

Adam Simkowski, Meteorologist
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Ella Dankanics, Meteorologist
Operations Risk Management
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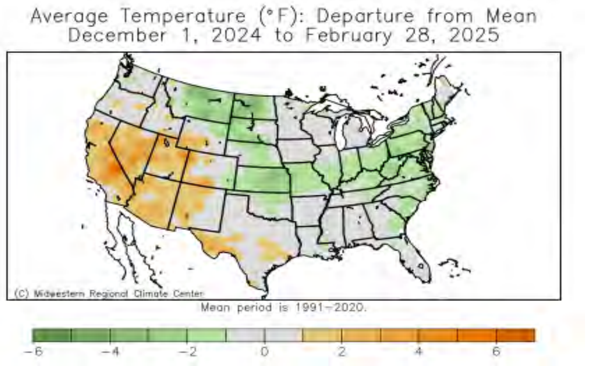
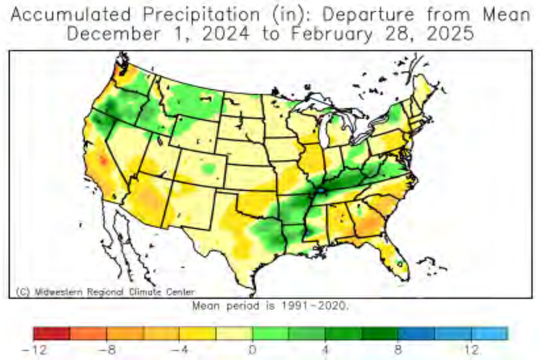
Last winter, which was colder than normal due to more durable cold, is the top analog year for the upcoming winter

Winter 2024-25

- Near normal to below normal temperatures across MISO's footprint
- Below normal temperatures were prevalent across MISO's North and Central regions for longer stretches than in recent history
- Seven days at or below 10°F systemwide during the January and February winter storms
- Systemwide temperatures were nearly as cold as the winter of 2017-2018 across MISO
- Above normal precipitation in MISO Central and South, including snow in New Orleans



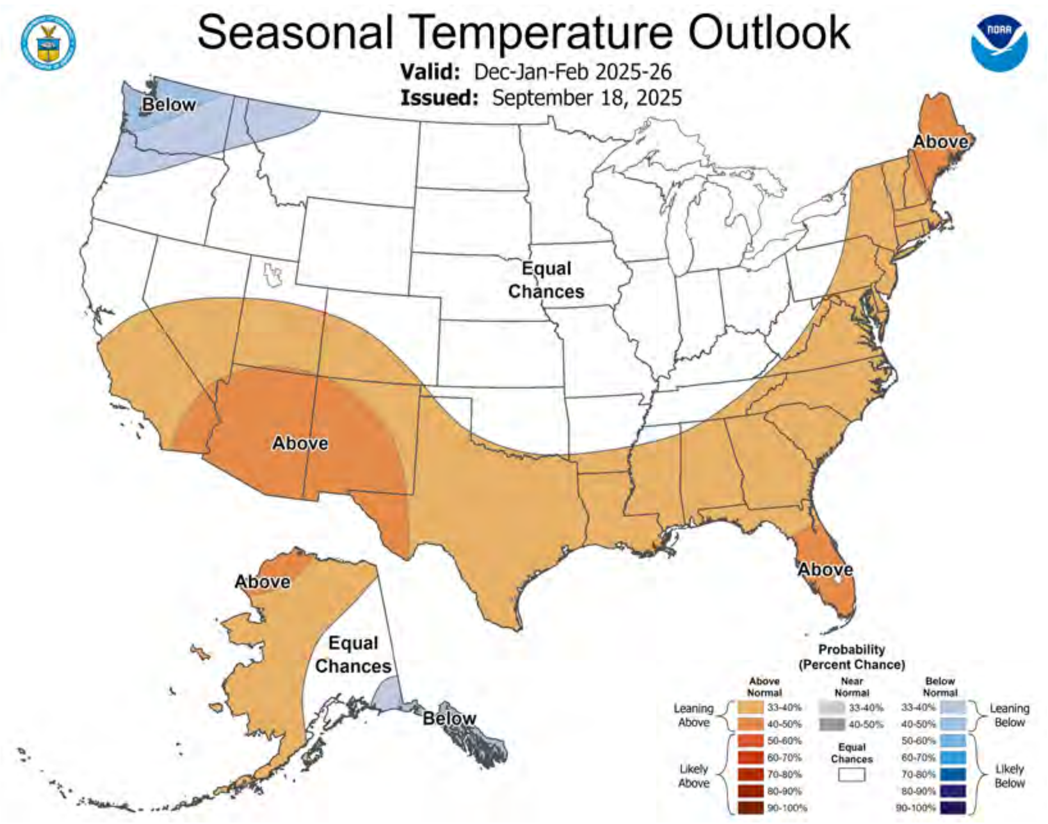


Midwestern Regional Climate Center
Cli-MATE: MRCC Application Tools Environment

TEMPERATURES

NOAA anticipates equal chances for the North and Central regions this winter, indicating more variability.

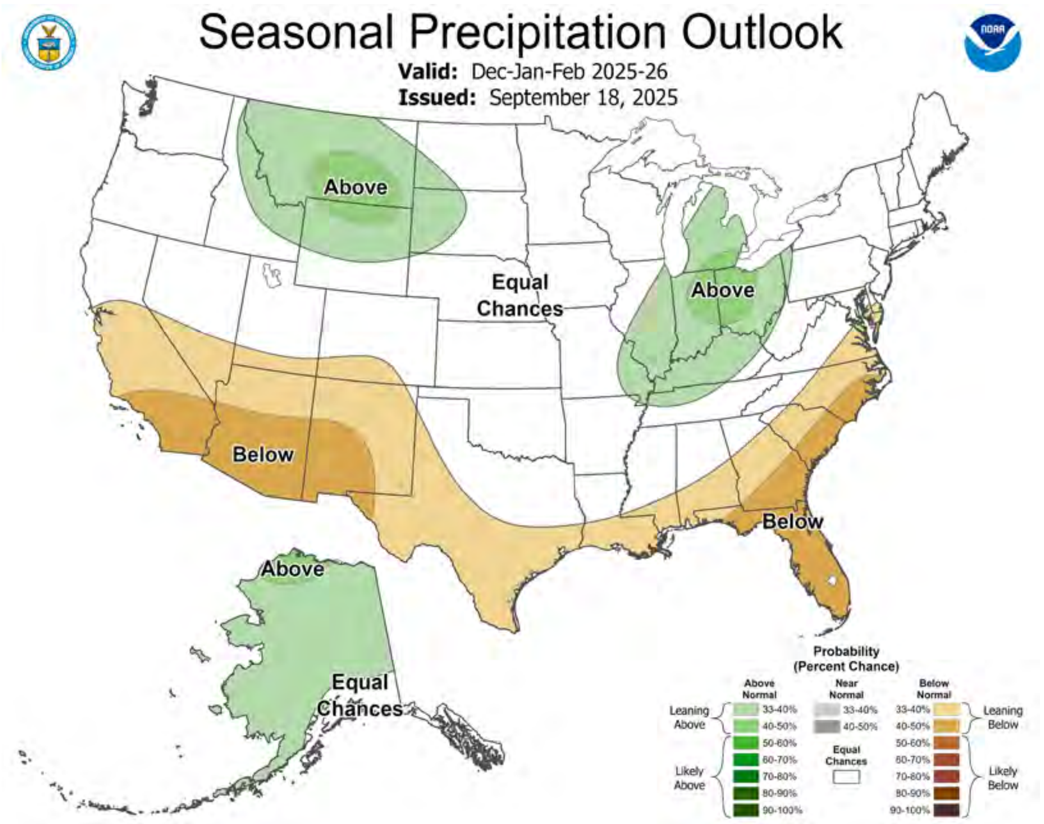
The South region is expected to trend above normal



PRECIPITATION

NOAA anticipates above normal precipitation for the Great Lakes this winter

Drier on the Gulf Coast



Historical Analog (Reference) Years

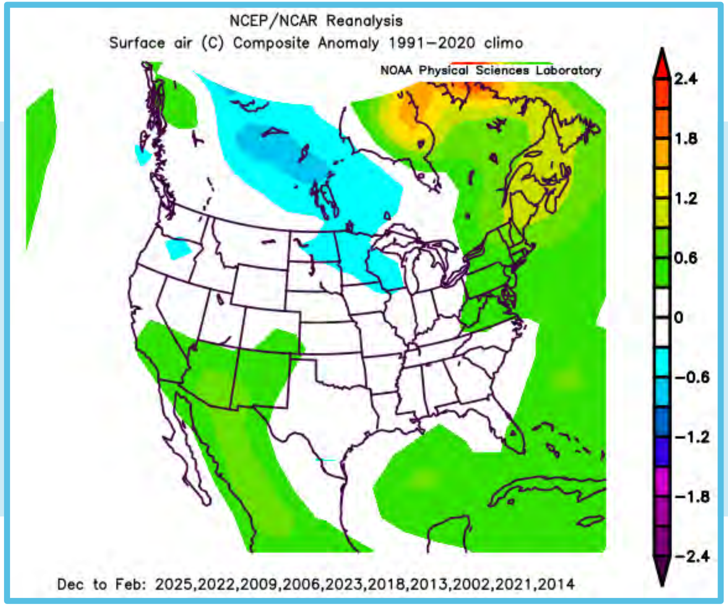
Analog years for Winter 2025-2026

	Vendor A	Vendor A Rank	Vendor B	Vendor B Rank
Year(s)	2024-25	1	2024-25	1
	2021-22	2	2012-13	2
	2008-09	3	2021-22	3
	2005-06	4	2022-23	4
	2022-23	5	2011-12	5
	2017-18	6	2016-17	6
	2012-13	7	2017-18	7
	2001-02	8	2001-02	8
	2020-21	9	2005-06	9
	2013-14	10	2013-14	10
			2019-20	11

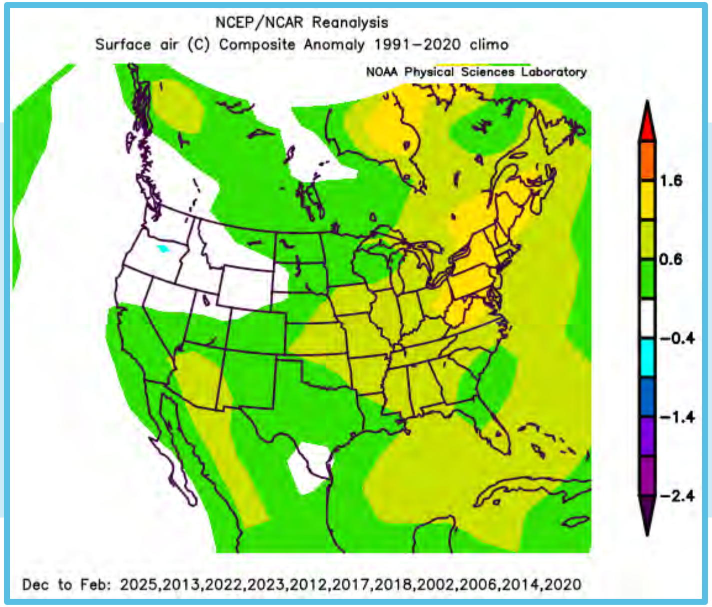
Cold MISO Winter
Warm MISO Winter
Normal MISO Winter

Analysis of historical analog years for each vendor supports a near-normal winter forecast with elevated variability

Vendor A



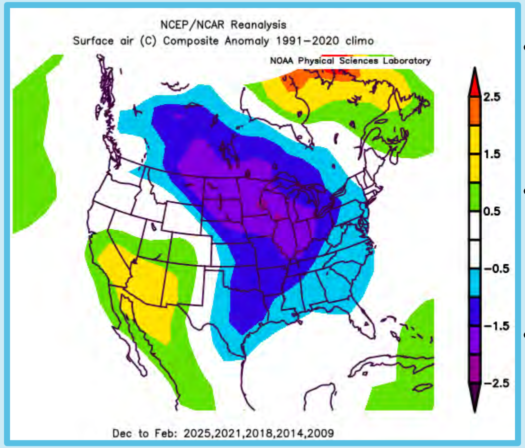
Vendor B



Analysis included December through February average temperature composites

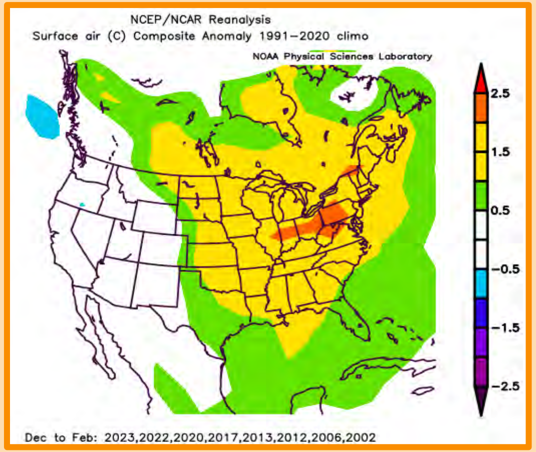
Risks to the Forecast

Colder Risk
(higher probability)



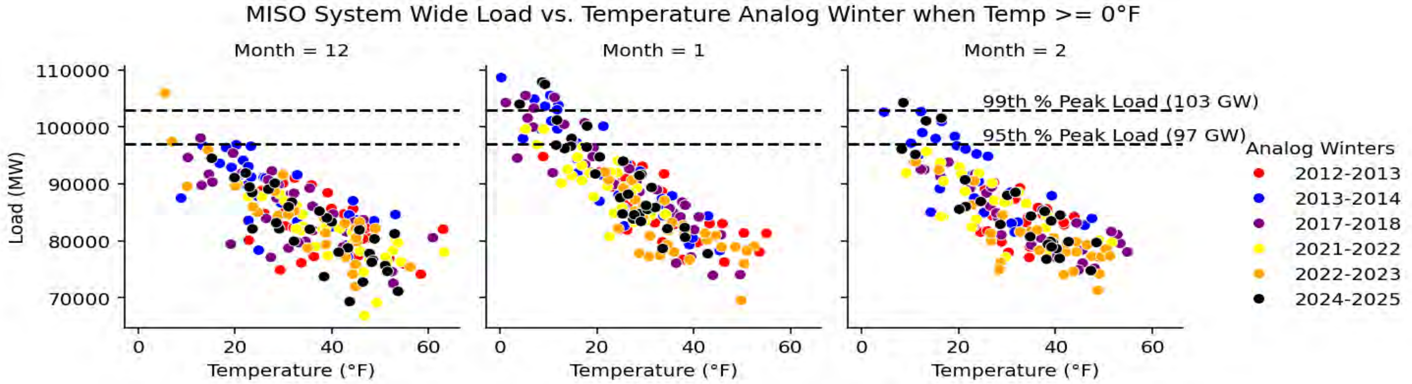
- Weaker La Niña opens the door for more cold shots throughout winter as is the current forecast.
- Other ocean/atmospheric forcing mechanisms drive the winter pattern including weaker stratospheric winds.
- Polar vortex disruptions could be elevated this winter

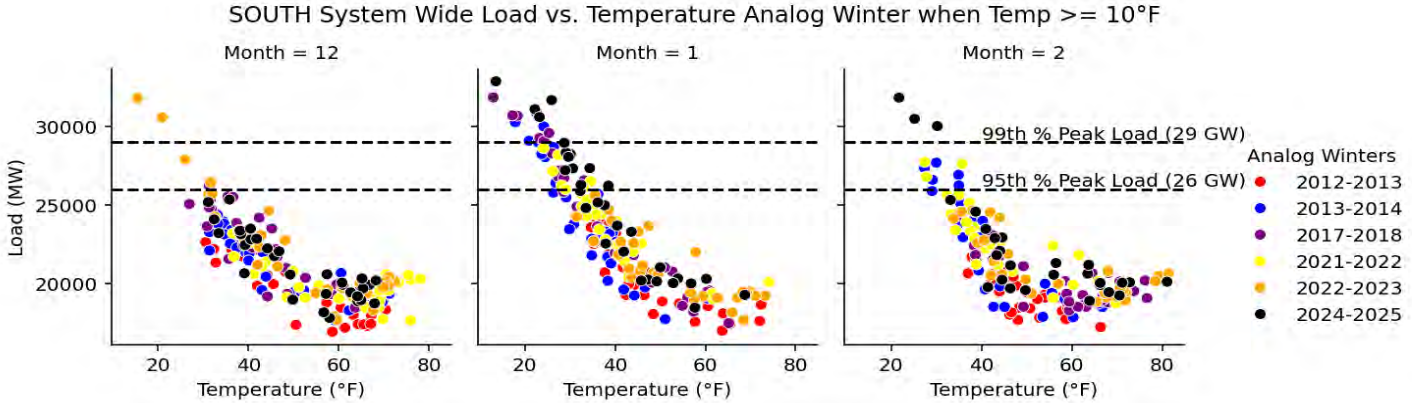
Warmer Risk
(lower probability)



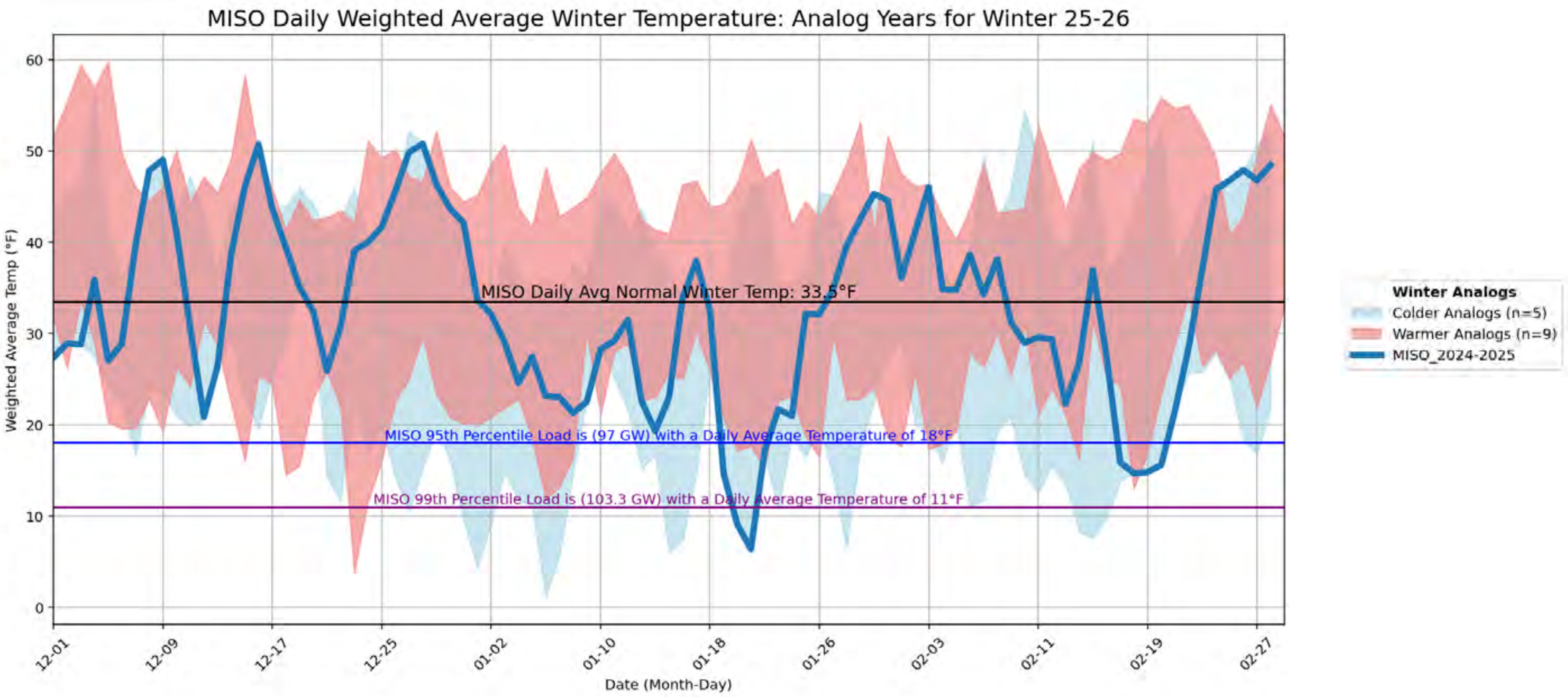
- Moderate to Stronger La Niña development allows for the Southeast Ridge to bring warmth farther north into MISO.
- Warm ocean temperatures around Indonesia allow for a warmer signal.

Historical Weak La Niña years: Systemwide peak load reaches 95th percentile ~97 GW

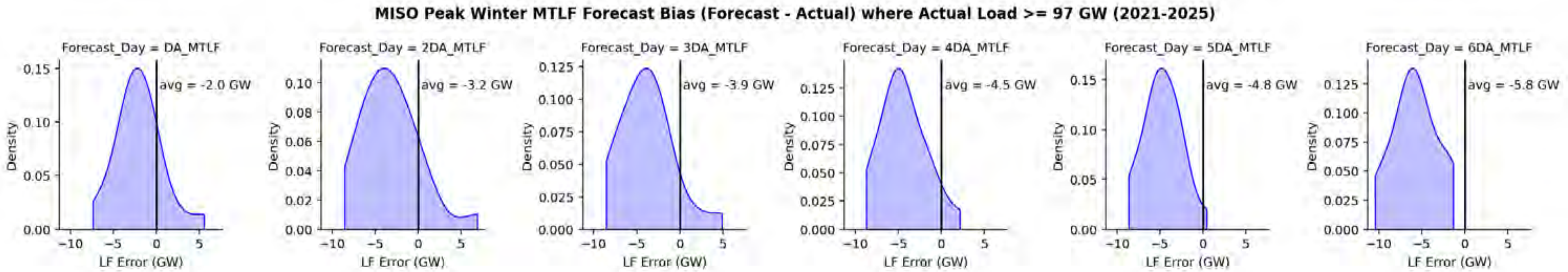


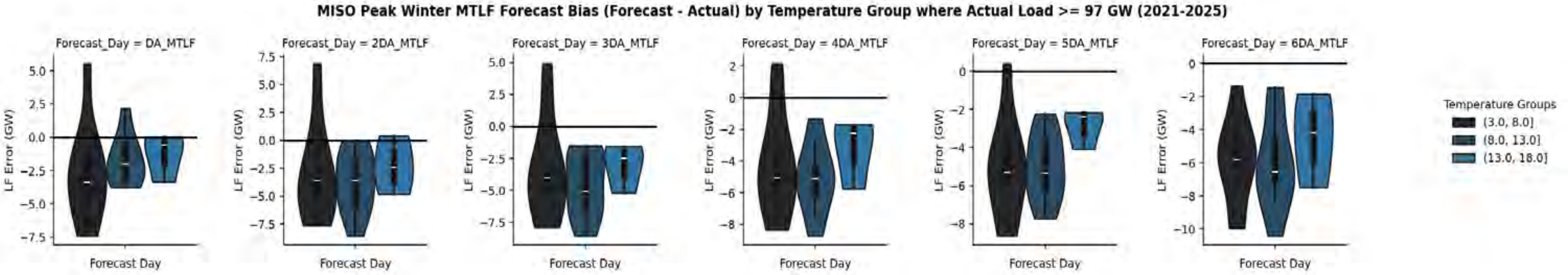


MISO Daily Average Temperatures: Analog Years



Seasonal Load Forecast Bias: Consistent under-forecast bias

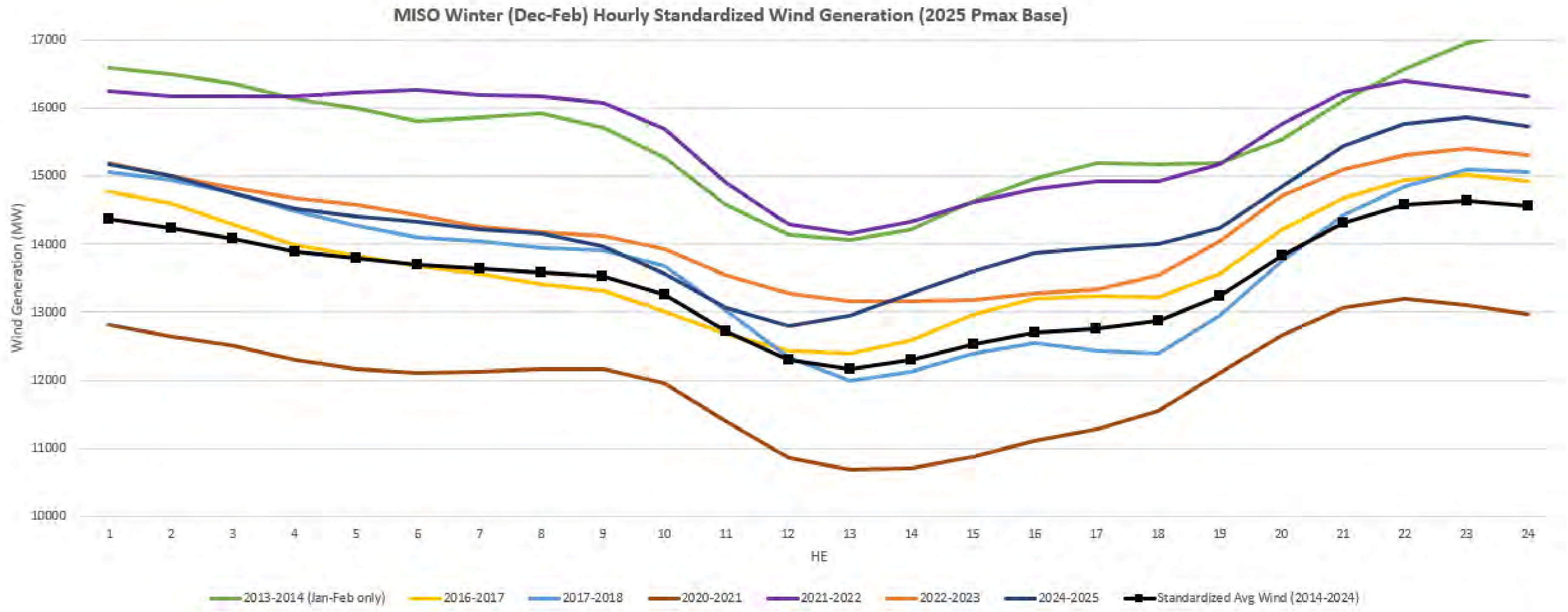




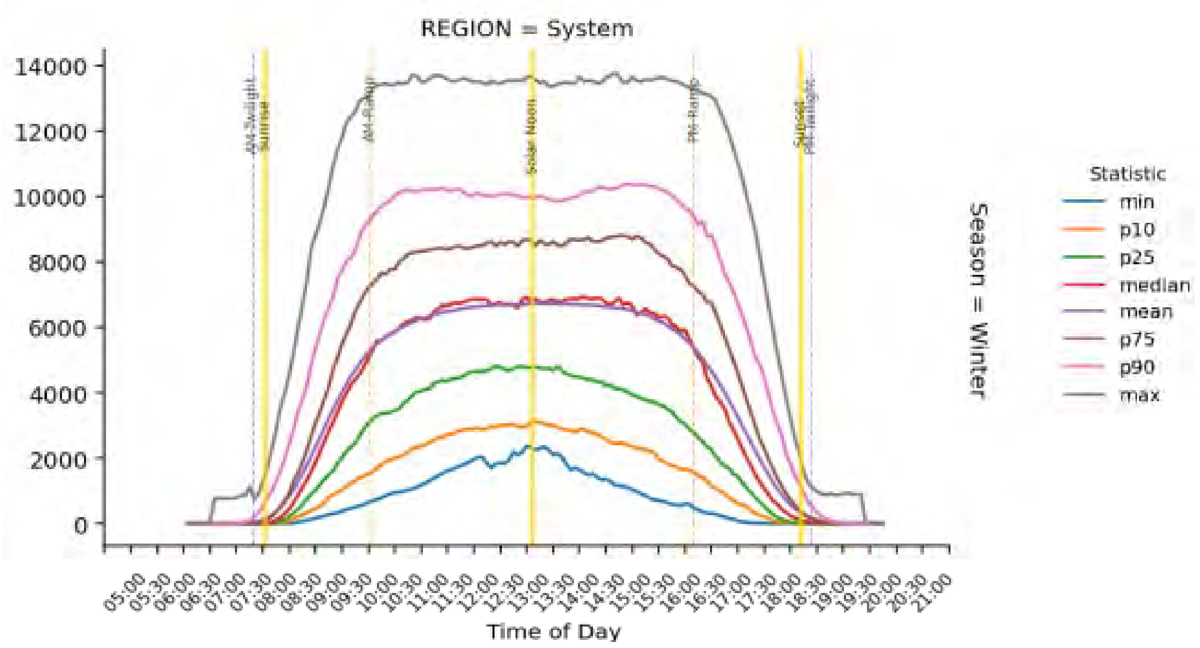
Winter weather can have major impacts to real-time operations of renewable resources

- MISO has used historical winter events to collaborate with vendors and market participants
- MISO's potential power loss of wind is 24.4 GW when temperatures <= -30 Degrees Fahrenheit
- MISO's forecasts consider icing, MISO considers the associated risks

Analog winters indicate normal to above normal wind generation



With solar rapidly growing, what does solar generation look like in Winter at the latest MISO Pmax?



Weather Summary

- North and Central Region temperatures expected to be normal to slightly below normal
  - This is highly dependent on frequency/intensity of cold shots throughout winter
- Above normal temperatures are expected in the South Region on average
- An active storm pattern expected with above normal precipitation across the Great Lakes
- Dry conditions expected across much of the South Region throughout the winter

Adam and Ella's Opinion

- The La Niña *(ocean-atmosphere)* looks to be more of a weak signal this upcoming winter; but still driving the underlying pattern. Cold air outbreaks have a greater likelihood with a weak La Niña
- Monitoring other atmospheric and oceanic signals throughout the winter will be more impactful to the MISO footprint from a temperature perspective
- Weaker stratospheric winds expected this winter can lead to more Polar Vortex disruptions
- An above normal winter in the South Region is expected, but doesn't preclude cold shots extending into the South region
- Precipitation is expected to be elevated in MISO's North/Central region which can increase icing and snowfall creating more renewable forecast difficulties

Questions?

2025-26 Winter Readiness: Generation

Gurman Kaur, Senior Engineer
Resource Adequacy
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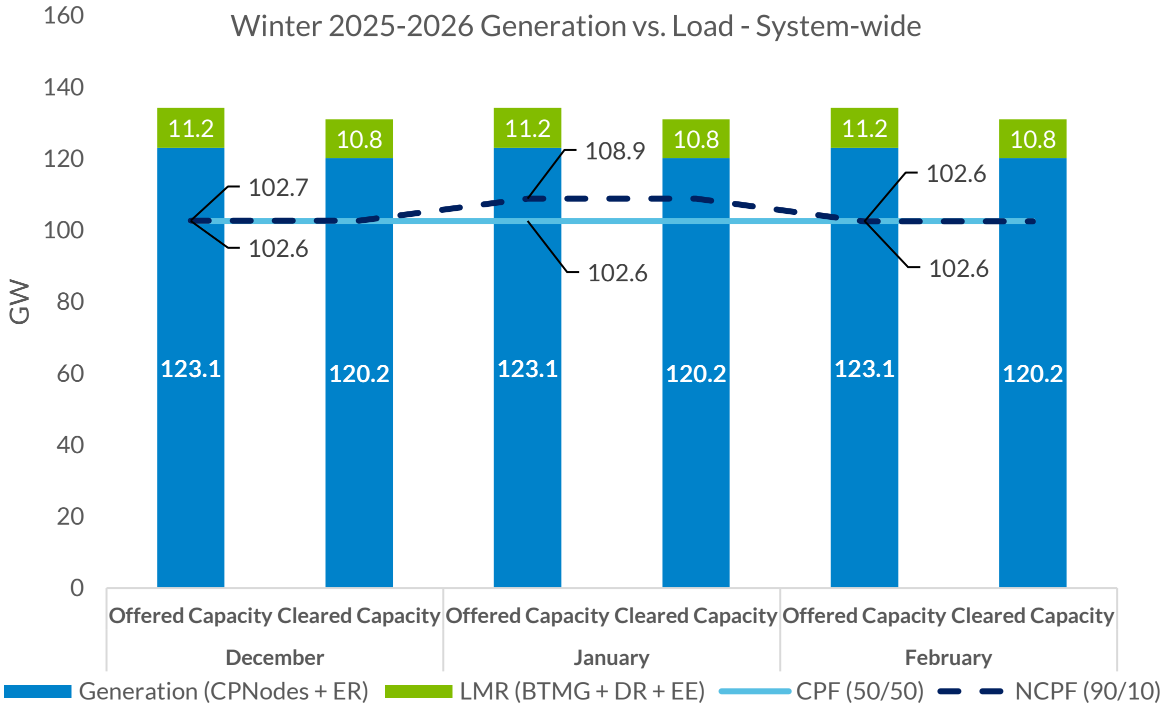
MISO projects sufficient capacity to cover both Coincident and Non-Coincident peak forecast load(s)

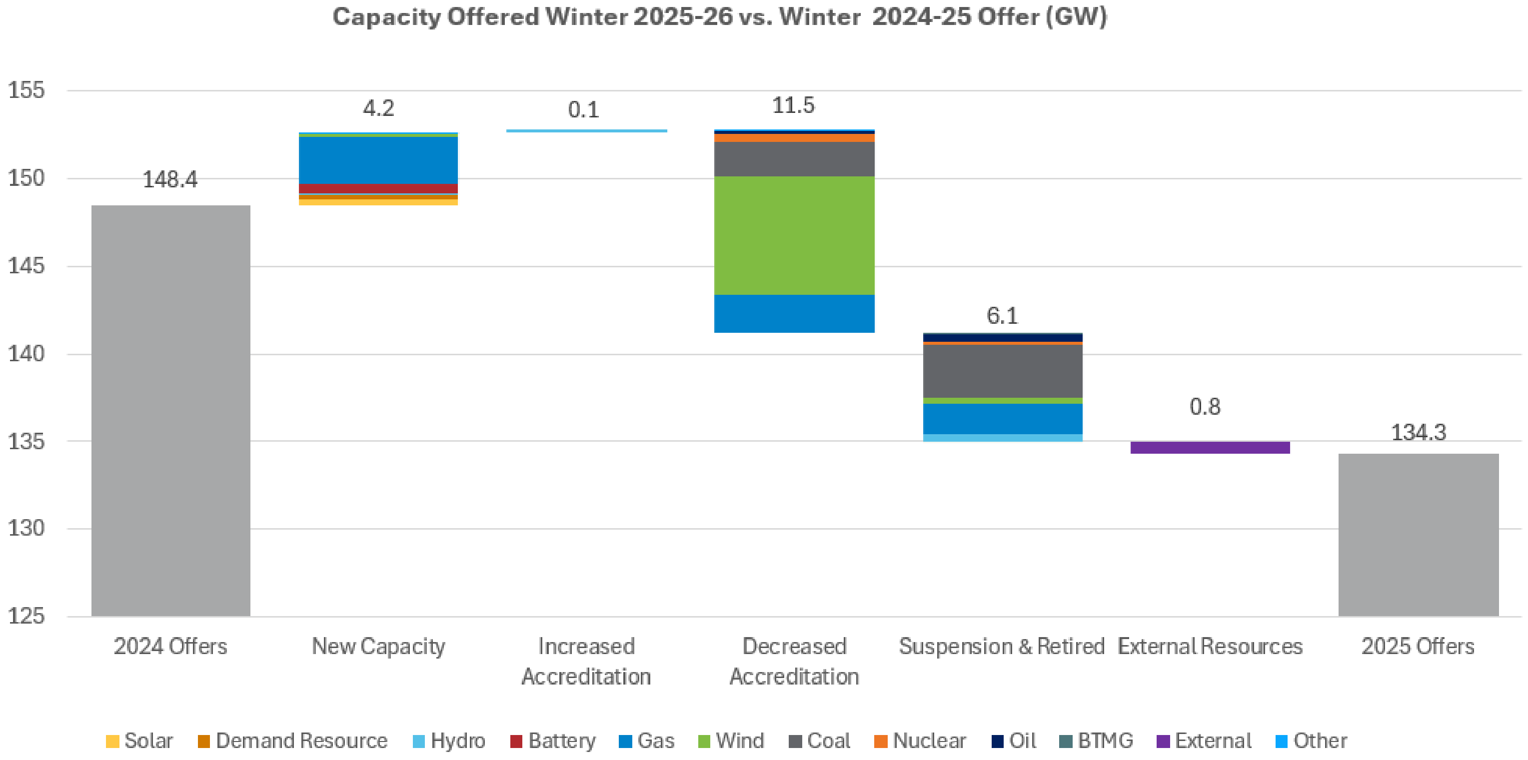
- **Coincident Peak Forecast** values are submitted by MISO Load Serving Entities, relative to MISO Seasonal peak.

- **Non-Coincident Peak Forecast** values are submitted by MISO Load Serving Entities, relative to each entity's monthly peak.



Source for CPF and NCPF data for Winter 2025-2026 is MISO PRA and load forecast submission process based on MISO Tariff, Module E-1.
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

The Winter 2025-2026 Planning Resource Auction (PRA) resulted in a decrease in surplus ZRCs in comparison with the Winter 2024-2025 PRA



Due to enhancements to the LOLE model development process, risk in the winter shifted to those hours when wind is less effective, resulting in lower winter wind accreditation than the previous year. For thermal resources including coal and gas, accreditation reduced due to historical performance.

Questions?

2025-26 Winter Readiness: Transmission

Fisseha Zewdu, Senior Engineer
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Executive Summary

- MISO is well positioned to handle unplanned events for the upcoming Winter season
- Several studies simulated unplanned events and extreme conditions on the MISO Winter system
- Results were used to identify potential adverse conditions and develop mitigations ahead of real-time operations

The Coordinated Seasonal Assessment study is used to identify potential issues and develop plans

Purpose:
Evaluate expected conditions across MISO footprint for Winter 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 2025 Winter model was built from the Eastern Interconnection base case with MISO Transmission projects and planned outages applied

Base Case:

- Built on the 2025/26 Winter ERAG MMWG model
- Generator Retirements approved on or before May 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 December through February
- 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 uncover any contingencies without operating plans for the winter season

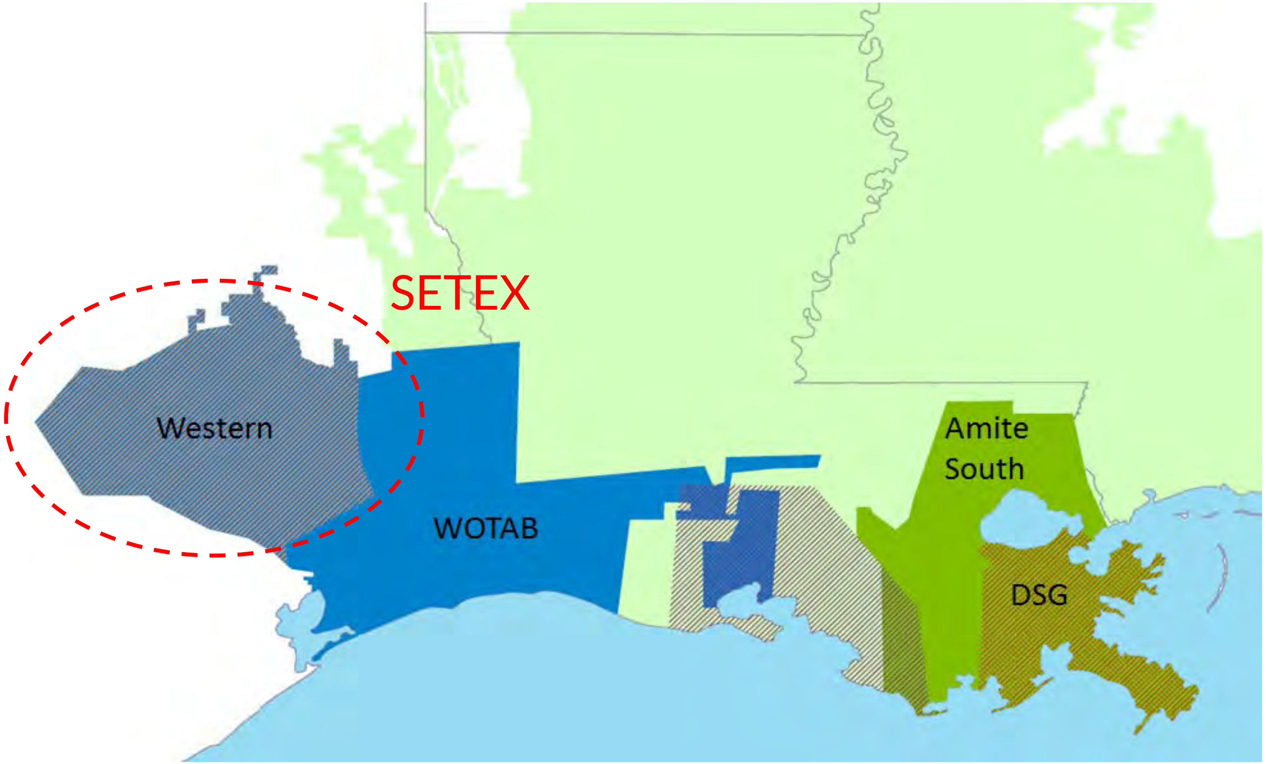
Approximately 18,500+ contingencies studied

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 runs import studies regularly for the load pockets

- The peak load conditions for the three MISO load pockets are simulated:
  - Amite South at **7201** MWs.
  - Downstream of Gypsy (DSG) at **2990** MWs
  - Southeast Texas (SETEX) at **6086** MWs
- Transfer studies into the pockets are performed.
- Results used to identify import limits for the pockets.



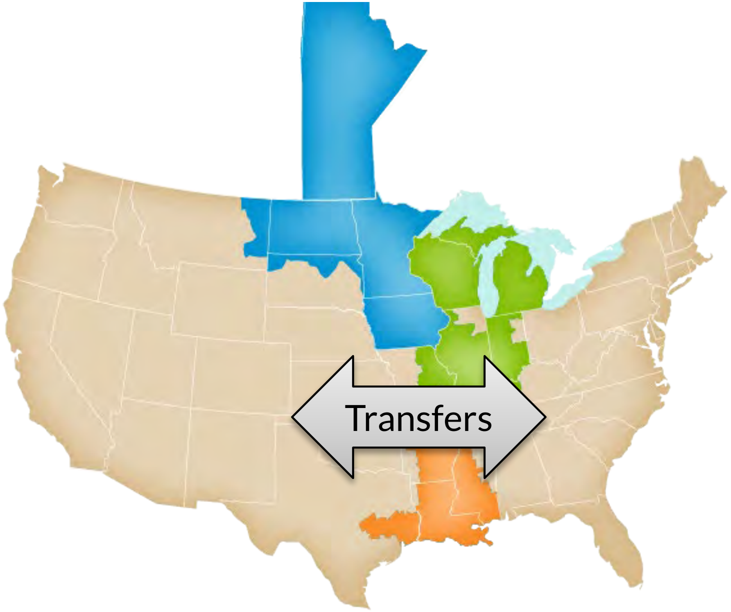
Load pocket transfer results indicate that import limits are in line with current operating guides

Load Pocket	Monitored Element	Limiting Contingency	Violation Type	Import Capability (MW)
AMITE SOUTH	Tali Sheek – Bakers Corner 230 kV	French Branch - Logtown 230 kV + Ninemile Point Unit 5	Thermal	3,222
DSG	Good Hope – Prospect 230kV	Waterford– Churchill 230 kV and Ninemile Point Unit 5	Thermal	2268
***SETEX**	*Failed to converge	Rocky Creek – Crocket 345 + MCPS Full Station	Thermal & Voltage	2625 (Last cnvg limit)

* Additional generation or reactive resources are required to maintain voltage/reactive balance under this contingency

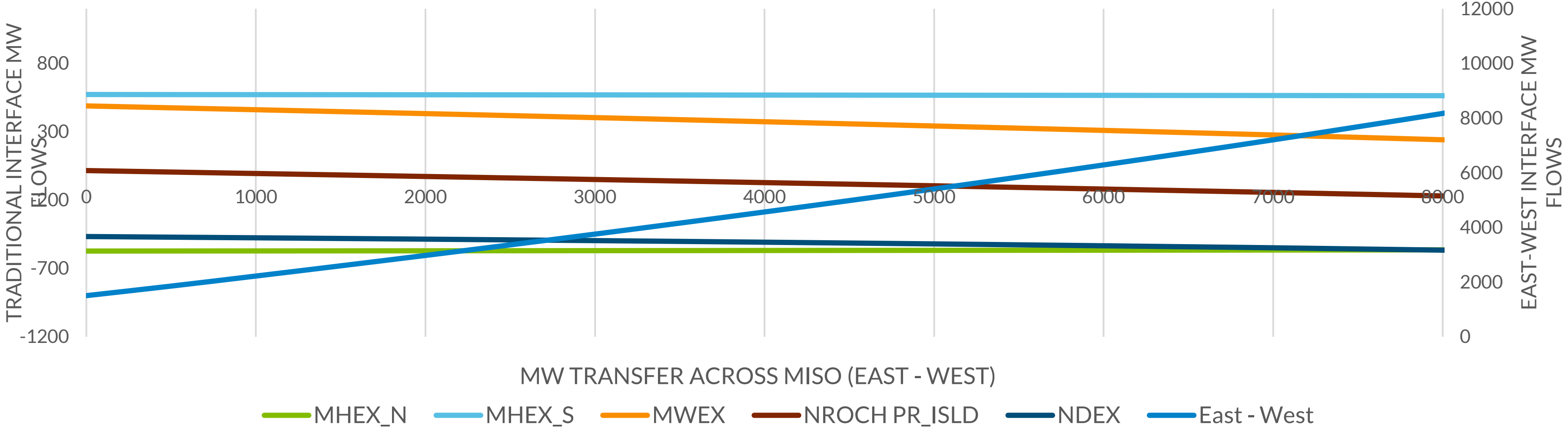
Bi-directional transfer studies across the MISO footprint identify main constraints with transfers between MISO neighbors

- 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.



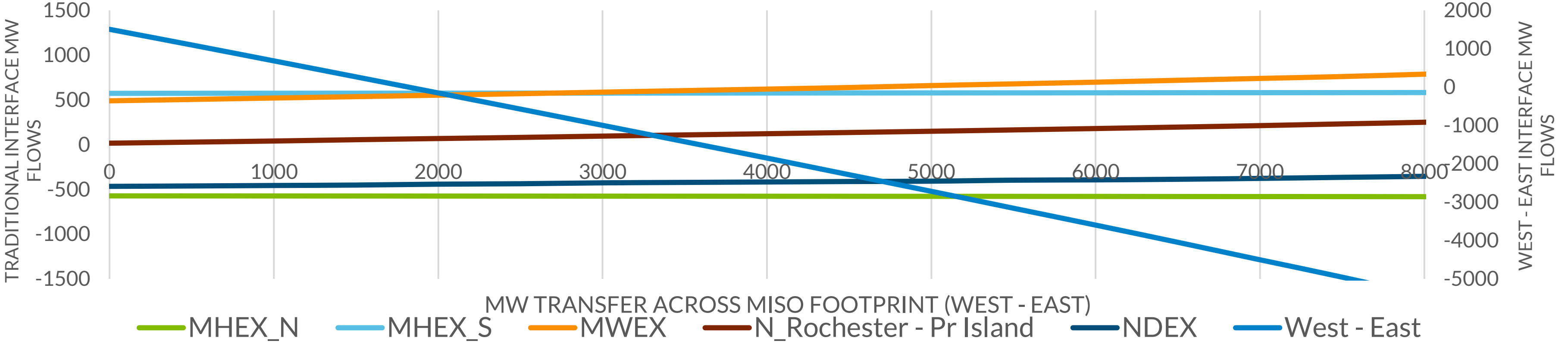
East to West transfer leading constraints and interface flows were identified during this study

Monitored Facility	Rating	Area	Contingency Name	DC TrLim	AC TrLim
338674 5DRY_CRK% 161 338103 5GRNFOREST.S 161 1	223	EES-EAI	EAOKE001: ARKANSAS NUCLEAR - FT SMITH 500	6976.9	6976.9
338814 5SOUTHLAND# 161 338125 5MT HOME 161 1	162	EES-EAI	EA16039: HARRISON EAST-HILLTOP 161	4527.9	4704.5
338874 3LEWISVILLE# 115 338875 3PATMOS.W# 115 1	159	EES-EAI	EAEE010: ELDORADO - MT OLIVE 500	6417.3	5775.7



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

Monitored Facility	Rating	Areas Name	Contingency Name	DC TrLim	AC TrLim
337427 8PERRYVILLE% 500 336830 8BXTRWILSON% 500 1	1940	EES-EMI/EES	EAEE010: ELDORADO - MT OLIVE 500	8925.7	9501.5
338056 CHALKBLUFFPV 500 338162 8W.MEMPHIS% 500 1	1732	EES-EAI	EA50001: DRIVER - SANBYU 500	7449.3	8569.4
635568 S HILLS 3 345 635630 BOONEVILLE 3 345 1	1195	MEC	MEC34116: MADISON CO - ORENTDRT 345	7716.2	7985.7



MISO

Questions?

2025-26 Winter Readiness: Winterization Survey

Mike Mattox, Advisor
System Operations
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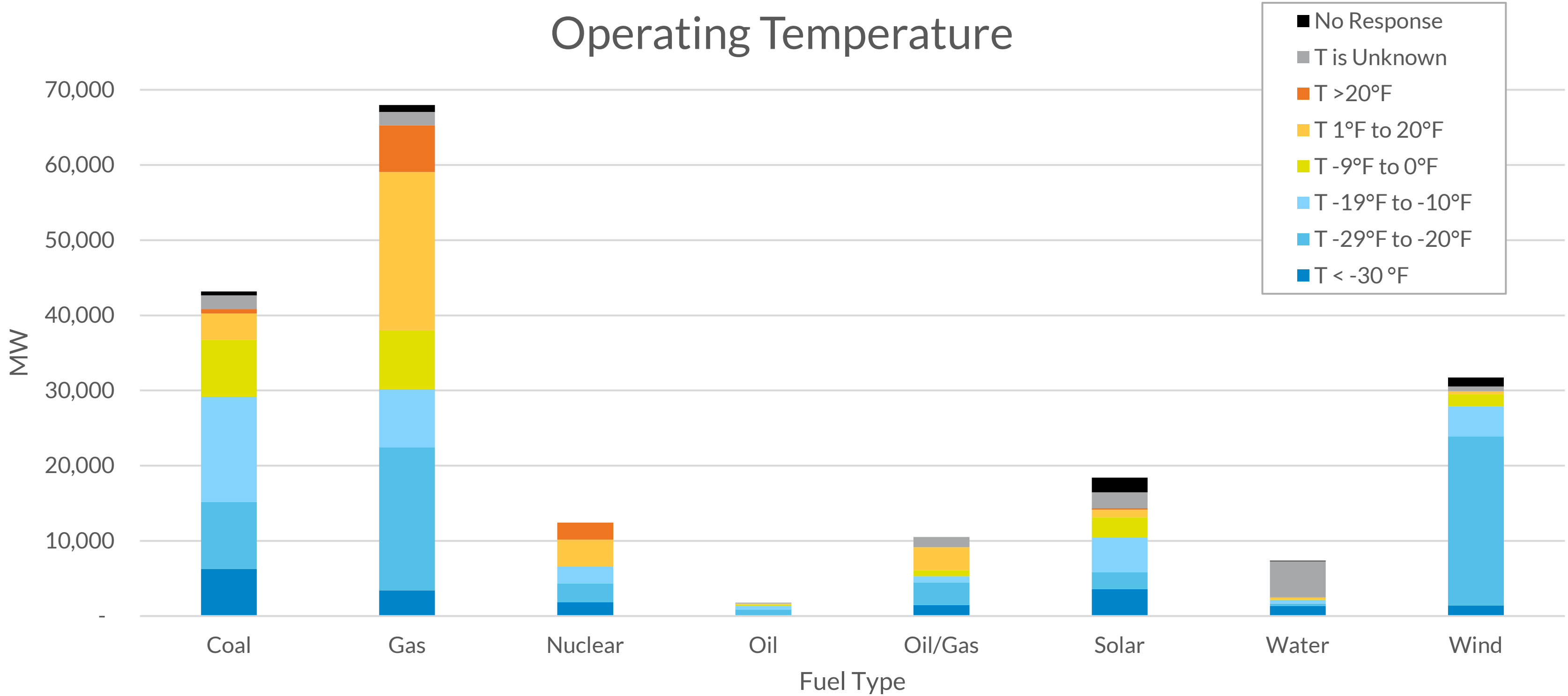
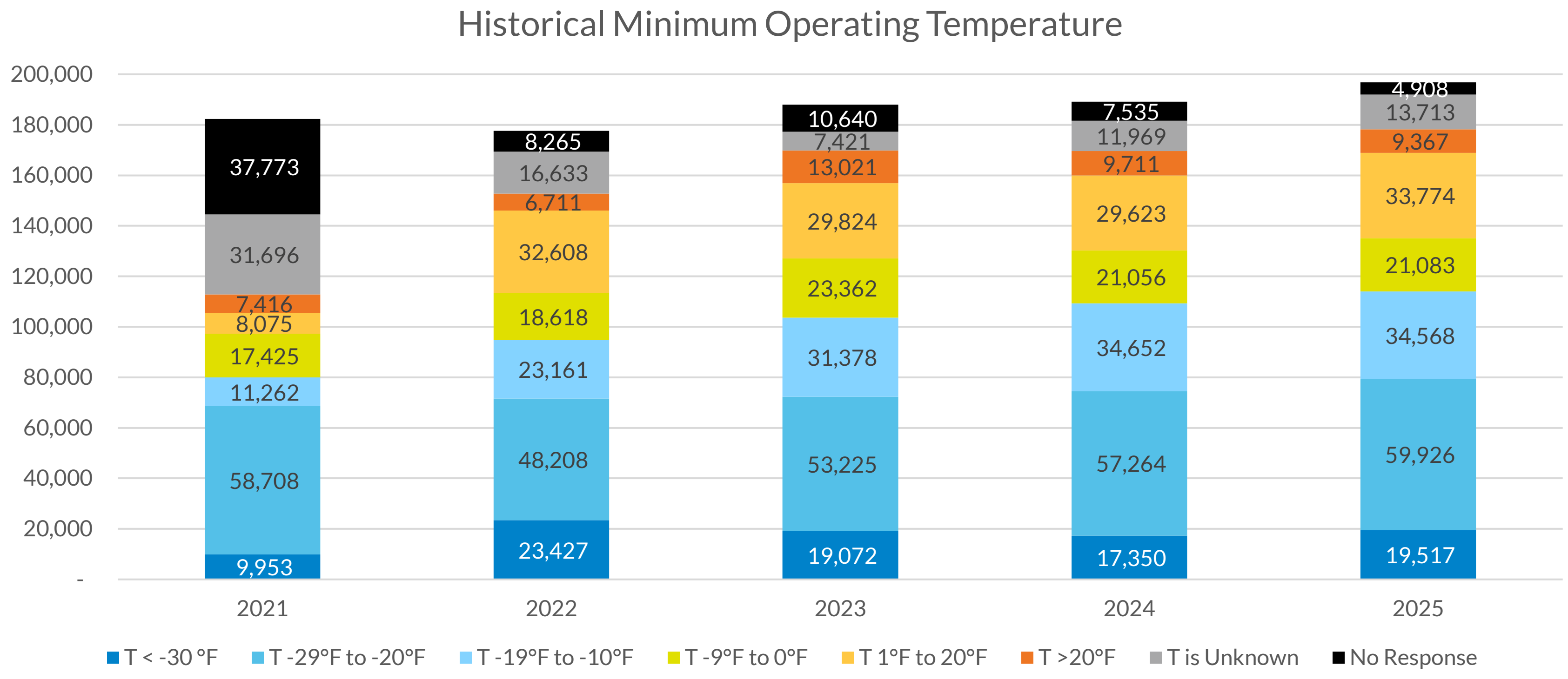
Cold Weather Operating Capability by Fuel Type



Fuel Types <1,000 MW Excluded

Cold Weather Operating Capability Continues to Improve



Questions?

2025-26 Winter Readiness: Uncertainty Management

Jason Howard, Director
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Matthew Campbell, Manager
Operations Risk Assessment
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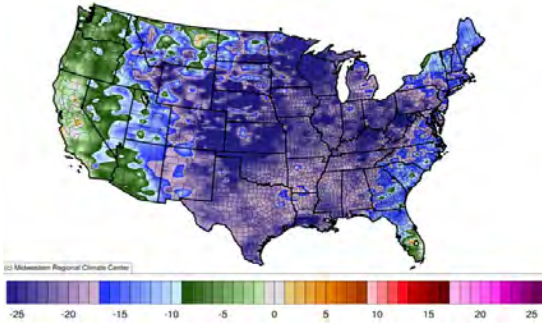
MISO and its members reliably and efficiently navigated several significant weather events last winter

WINTER STORMS BLAIR & CORA

- January 6-9
- Footprint-wide cold: 21.4˚F
- Systemwide peak demand: 98 GW*
- Strong fleet performance

WINTER STORM ENZO



Average temperatures, 30-year departure from normal

CONDITIONS

- January 20-22
- Footprint-wide extreme cold: 6.5˚F
- Systemwide peak demand: 108 GW*
- South Region peak demand: 33 GW*

OPERATIONAL HIGHLIGHTS

- Market participant actions
- Daily risk assessments and Uncertainty Management Model utilization
- Effective and efficient real-time commitments
- Ongoing congestion management efficiency

All-time systemwide winter peak demand –* ***109 GW* *(January 6, 2014) and previous South Region winter peak demand –* ***32.3 GW*** *(January 17, 2024)*

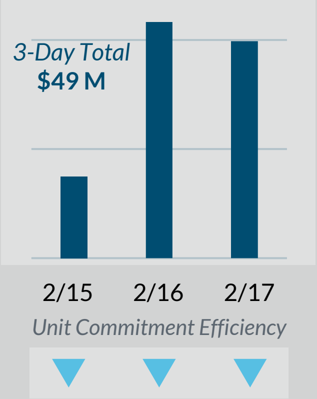
MISO

Work done for Operations of the Future has positioned MISO well for efficient reliability through the fleet transition, as evidenced by our performance across the last four major storms

URI
February 15-17, 2021
President's Day

Temperature	13˚F
Peak Demand	103 GW
Renewable Output	7 GW
Incremental Outages	21 GW

*Uplift**



ELLIOTT
December 23-25, 2022
Christmas

Temperature	3.7˚F
Peak Demand	107 GW
Renewable Output	19 GW
Incremental Outages	21 GW

*Uplift**

HEATHER
January 15-17, 2024
Martin Luther King Jr. Day

Temperature	15.5˚F
Peak Demand	106 GW
Renewable Output	17 GW
Incremental Outages	5 GW

*Uplift**

ENZO
January 20-22, 2025
Martin Luther King Jr. Day

Temperature	6.5˚F
Peak Demand	108 GW
Renewable Output	19 GW
Incremental Outages	9 GW

*Uplift**

**Uplift is also known as revenue sufficiency guarantee (RSG)*

Unit Commitment Efficiency (2024 thresholds)
Expected 91.5 % | Monitor 89.5 % | Review 87.5 %

MISO's Uncertainty Management Model continues to aid our operations in more confident and agile decision-making, resulting in efficient reliability

Uncertainty Management Model Process During Winter Storm Enzo – January 21

MISO's Uncertainty Management Model predicted high uncertainty for January 20-22

Successfully identified **January 21** as the day with the highest uncertainty

Forecast Uncertainty
HIGH (14.5 GW)

Based on the forecast uncertainty, MISO increased:

- Short-Term Reserve requirement to cover 99.7th percentile of risk
- Reserve margins

Actual Deviation**
HIGH (11 GW)

MISO Managed 11 GW of uncertainty in real-time due largely to unplanned generation outages

Despite high levels of actual deviation from the operating plan, MISO experienced positive outcomes

Uplift*
$1 Million

Unit Commitment Efficiency
93.4%

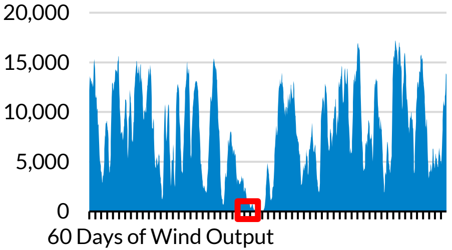
**Uplift is also known as revenue sufficiency guarantee (RSG)*
***The net load difference between the next-day operating plan and what occurs in real-time*

MISO

Operational challenges continue to be monitored with expected resource mix for upcoming winter season

LONG-DURATION OUTAGES

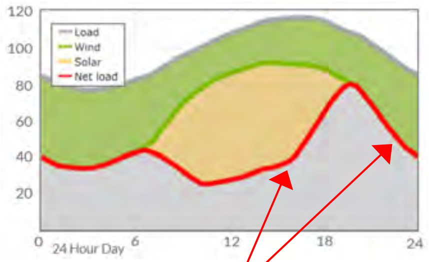
MISO Hourly Wind Output
January & February - 2020 (MW)



~40 hours of essentially zero wind

SHIFTING NET-LOAD SHAPES

Future System Net Load
Average Summer Day - 2032 (GW)



High ramp up need in early evening and high ramp down need middle of the night

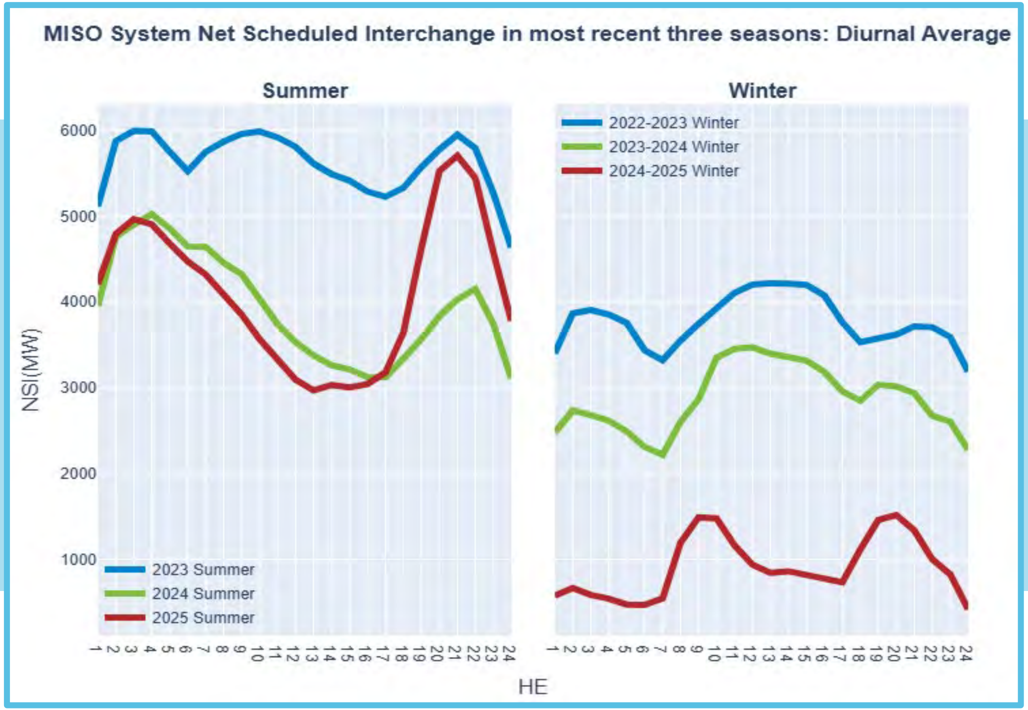
SYSTEM STABILITY CHALLENGES

Frequency & High-Wind Output
March 3, 2024

Wind is one of several factors that MISO has linked to increased frequency fluctuations

MISO

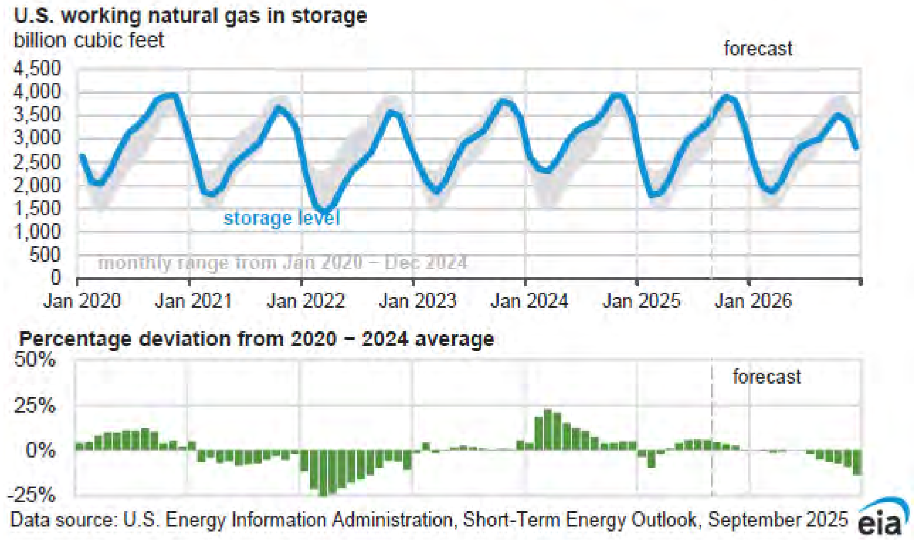
Net Scheduled Interchange (NSI) patterns continue to shift year over year

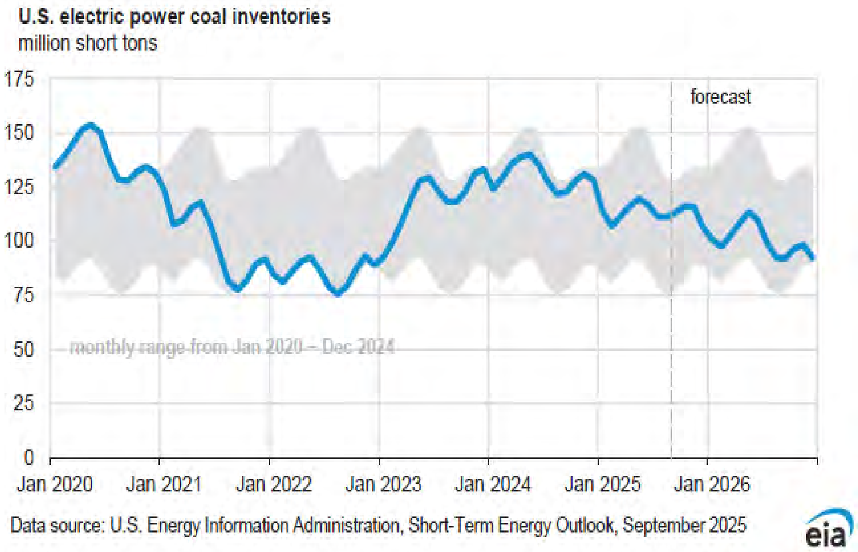


On average, MISO relies more on NSI during summer months than in winter

PJM accounts for the bulk of the NSI in winter months but has a declining trend

Dispatchable Thermal Generation Fuel Supply Outlook



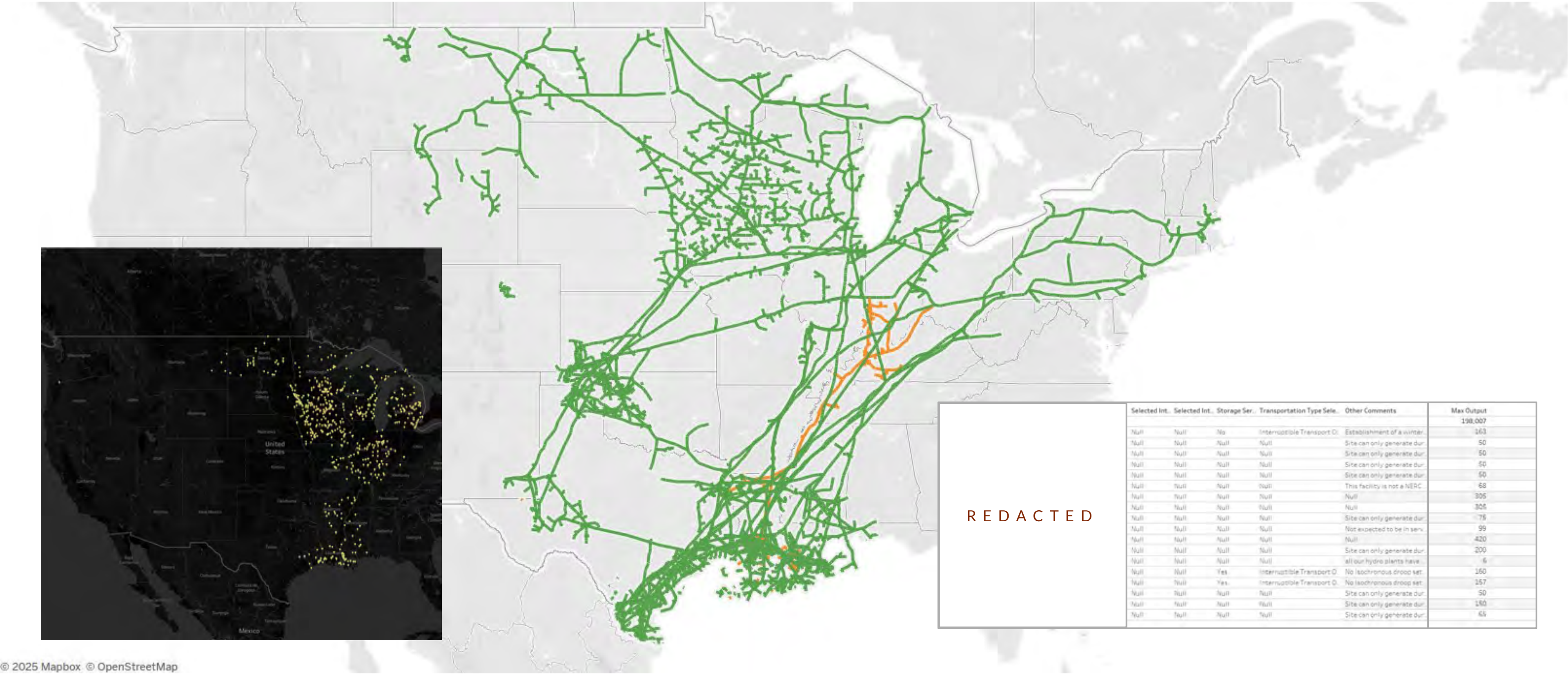


The balance between natural gas and coal generation will depend on fuel availability and delivery. Natural gas storage is projected to be lower than the 5-year average each month.

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

Operations Uncertainty Platform – Fail to Start Dashboard

Operations Uncertainty Platform – Gas Pipeline Risk Dashboard



REDACTED

Selected Int..	Selected Int..	Storage Ser..	Transportation Type Sele..	Other Comments	Max Output
					198,007
Null	Null	No	Interruptible Transport D..	Establishment of a winter..	163
Null	Null	Null	Null	Site can only generate dur..	50
Null	Null	Null	Null	Site can only generate dur..	50
Null	Null	Null	Null	Site can only generate dur..	50
Null	Null	Null	Null	Site can only generate dur..	50
Null	Null	Null	Null	This facility is not a NERC..	68
Null	Null	Null	Null	Null	305
Null	Null	Null	Null	Null	306
Null	Null	Null	Null	Site can only generate dur..	75
Null	Null	Null	Null	Not expected to be in serv..	99
Null	Null	Null	Null	Null	420
Null	Null	Null	Null	Site can only generate dur..	200
Null	Null	Null	Null	all our hydro plants have ..	6
Null	Null	Yes	Interruptible Transport D..	No Isochronous droop set..	160
Null	Null	Yes	Interruptible Transport D..	No Isochronous droop set..	157
Null	Null	Null	Null	Site can only generate dur..	50
Null	Null	Null	Null	Site can only generate dur..	150
Null	Null	Null	Null	Site can only generate dur..	65

Net Uncertainty Forecast and Dynamic Reserve

Market product	Reserve Requirement	Uncertainty Forecast
Short-Term Reserve	In PRODUCTION (DART) • Systemwide/Regional • Normal/High • Seasonal	In PRODUCTION ND FRAC Net Uncertainty Forecast Model
Ramp Capability Product	In REFINEMENT • Systemwide • Normal/High • Seasonal	In TESTING • Test through May 2026
Regulation	In PRODUCTION (DART) • Systemwide • Normal/High • Monthly	In TESTING • Test through May 2026

Note: status as of October 1, 2025

MISO

Forward looking Capacity Advisory and Conservative Operations declarations

- Goal of the Multi-Day Forward Reliability Assessment and Commitment process is to ensure we can meet reserve margin thresholds to manage projected operating conditions for Operating Day (OD) +1-6

- Reserve Margin = Total available generation – Total obligation + Net uncertainty

- Declarations can be 1-5 days in advance with no intraday Capacity Advisory declarations

- Conservative Operations considerations: generation availability and transmission deliverability

Operating Reserve Margin Thresholds

ND-FRAC Commitment Threshold Master Table

Primary Commitment Threshold Recommendation

Systemwide	
Forecast Uncertain..	Commitment Threshold (MW)
1-Low (Green)	REDACTED
2-Medium (Yellow)	REDACTED
3-High (Orange/Red)	REDACTED

North/Central	
Forecast Uncertainty	Commitment Threshold (MW)
1-Low (Green)	REDACTED
2-Medium (Yellow)	REDACTED
3-High (Orange/Red)	REDACTED

South	
Forecast Uncertainty	Commitment Threshold (MW)
1-Low (Green)	REDACTED
2-Medium (Yellow)	REDACTED
3-High (Orange/Red)	REDACTED

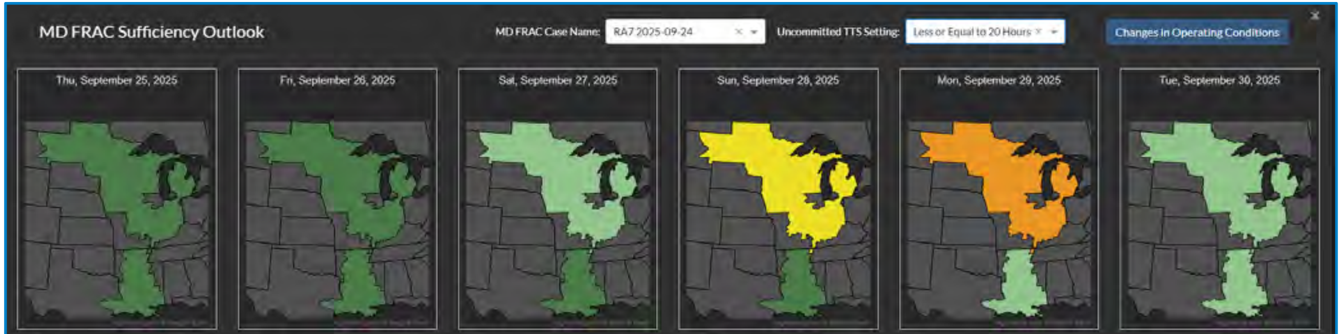
- Evaluated for each upcoming season to capture recent trends in uncertainty
- Threshold level determined from uncertainty forecast model

ND-FRAC: Next Day Forward Reliability Assessment and Commitment

MISO's operating reserve margin outlook is dependent on updated offers and outages from members

MKTDAY	PERCENT_UPDATED
2025-10-07 05:00:00.000	100%
2025-10-08 05:00:00.000	64%
2025-10-09 05:00:00.000	47%
2025-10-10 05:00:00.000	36%
2025-10-11 05:00:00.000	26%
2025-10-12 05:00:00.000	26%
2025-10-13 05:00:00.000	10%

MISO issues declarations using the best available information to provide situational awareness



Region	RM	RM %	Region	RM	RM %	Region	RM	RM %	Region	RM	RM %	Region	RM	RM %	Region	RM	RM %
MISO	14,479.8	16%	MISO	16,585.5	19%	MISO	9,971.2	12%	MISO	5,890.6	7%	MISO	2,392.5	2%	MISO	6,623.7	7%
N/C	7,701.3	12%	N/C	9,302.3	15%	N/C	4,904.7	8%	N/C	2,040.1	3%	N/C	42.5	0%	N/C	4,231.2	6%
South	6,786.5	26%	South	7,291.2	29%	South	5,074.5	20%	South	3,855.5	15%	South	2,358	9%	South	2,400.5	9%

Questions?

Winter Readiness 2025 Technical Development

Anita Hurst, Manager
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MISO Cold Weather Drill

Learning Objectives

1. Summarize the events and effects of a major winter storm's impact on the BES.

2. Explain the impacts of severe weather on generation and the effects of generation loss.

3. Explain the effects of large scheduled increases through MISO's footprint.

4. Analyze lessons learned from a recent major winter storm event and how to apply those lessons to future events.

Agenda

- **Introduction/Why Are We Here?**
- **Winter Storm Uri**
- **Winter Storm Elliott**
- **Winter Storm Heather**
- **Uri vs Elliott & Uri/Elliott vs Heather**
- **2025 Arctic Event**
- **VOLL Pricing Review**
- **Discussion Activity**
- **Create Your Own Winter Storm**
- **Final Debrief/Wrap-up**

MISO Power System Restoration Drill

Learning Objectives

1. Assess system conditions, communicate using 3-part communication and practice implementing system restoration plans

2. Describe actions to restore identified critical transmission, generation, loads and transmission paths to nuclear plants

3. Assess readiness for connecting to neighboring systems

4. Resync systems to neighboring TOPs and the Interconnection

Agenda

- Introduction/Scenario Review
- Simulation Begins (restore in MISO Simulator)
- Interconnection Checklist
- Transfer of Control
- Restoration Continues
- Voltage and Reactive Resources
- Day One Wrap Up & Progress Report
- Restoration Continues from Pre-Built Islands
- Critical Facilities Discussion
- Final Debrief/Wrap-up

Questions?

Market Capacity Emergency EOP-002 Updates

Don Hunter, Manager
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Carmel Control Room
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Market Capacity Emergency Procedure Changes Summary

- **Precautions**
  - Reserve Margin entry conditions are now based on **forecasted uncertainty levels** for the operating day(s), not just outages or other risks
- **Capacity Advisory Entry Conditions**
  - Now triggered when forecasted Reserve Margin < threshold tied to the uncertainty level – <u>no longer a fixed < 5% or South Region only trigger</u>
  - Capacity Advisory Declaration made OD+1 to OD+4
  - Entry conditions for Max Gen Alert and higher remain the same

Market Capacity Emergency Procedure Changes Summary

- **Additional Steps**
  - Added ability to declare **Conservative Operations** at the Capacity Advisory level if warranted
  - In **Max Gen Warning,** added step to notify GOPs with environmental de-rates to obtain waivers early if escalation to **Max Gen 2a** or higher is anticipated
- **Removed Priority 6-NN Tag Steps**
  - Step 3b references have been deleted. We no longer upgrade priority 6 tags to 7 in this step

Market Capacity Emergency Procedure Changes Summary

- **Event Step 4b/5**
  - Added note for maintaining appropriate **Regulating Reserves** to avoid firm load shed for normal ACE deviations
  - Added note that the **SM will ensure Firm Load Shed points are known** and members are prepared to execute Load Shed when reserves are depleted and additional action is required such as during increasing load conditions or ACE recovery from generation loss

Market Capacity Emergency Procedure Changes Summary

- **Downgrade/Termination**
  - Added actions to **end emergency energy purchases** and **reload export curtailments** made during the event
- **Administrative**
  - Removed **MBAA Sub-Region** definition and all mentions in procedure per Tariff

Questions?

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 142

MISO Winter 2024–2025 Operations Report

MISO Operations Report

Markets Committee of the
Board of Directors

March 11, 2025

Executive Summary

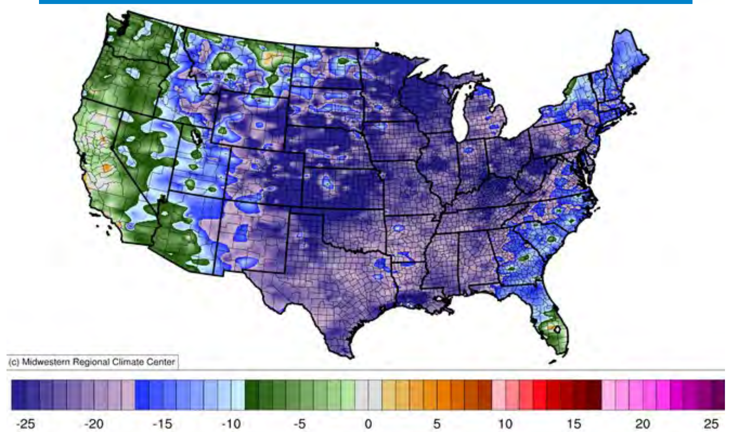
- MISO operations experienced a busy start to the year with significant winter weather events; the Uncertainty Management model aided MISO and its members in delivering efficient reliability
- MISO continues to improve the management of these events and is seeing progress as we review the outcomes of the last four winter weather events
- Reliability, market and operational functions performed as expected this winter, and MISO anticipates sufficient supply to cover demand under typical conditions this spring

MISO and its members reliably and efficiently navigated significant weather events this winter season

WINTER STORMS BLAIR & CORA

- January 6-9
- Footprint-wide cold: 21.4˚F
- Systemwide peak demand: 98 GW*
- Strong fleet performance

WINTER STORM ENZO



Average temperatures, 30-year departure from normal

CONDITIONS

- January 20-22
- Footprint-wide extreme cold: 6.5˚F
- Systemwide peak demand: 108 GW*
- South Region peak demand: 33 GW*

OPERATIONAL HIGHLIGHTS

- Market participant actions
- Daily risk assessments and Uncertainty Management Model utilization
- Effective and efficient real-time commitments
- Ongoing congestion management efficiency

All-time systemwide winter peak demand – **109 GW (January 6, 2014) and previous South Region winter peak demand – **32.3 GW** (January 17, 2024)*

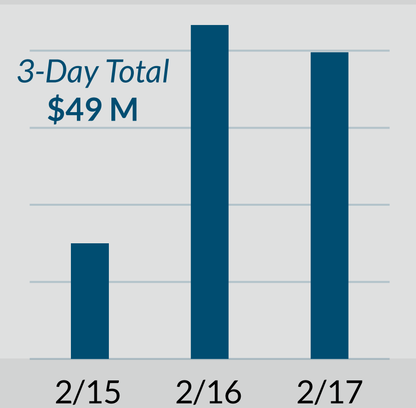
Operations of the Future work has positioned MISO well for efficient reliability through the fleet transition, as evidenced by our performance across the last four major storms

URI

February 15-17, 2021
President's Day

Temperature	13˚F
Peak Demand	103 GW
Renewable Output	7 GW
Incremental Outages	21 GW

*Uplift**



Unit Commitment Efficiency

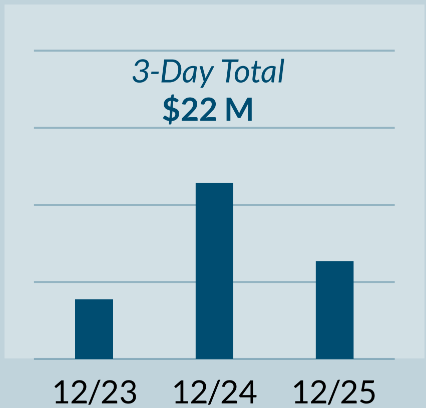
▼ ▼ ▼

ELLIOTT

December 23-25, 2022
Christmas

Temperature	3.7˚F
Peak Demand	107 GW
Renewable Output	19 GW
Incremental Outages	21 GW

*Uplift**



Unit Commitment Efficiency

▼ ▼ ●

HEATHER

January 15-17, 2024
Martin Luther King Jr. Day

Temperature	15.5˚F
Peak Demand	106 GW
Renewable Output	17 GW
Incremental Outages	5 GW

*Uplift**

Unit Commitment Efficiency

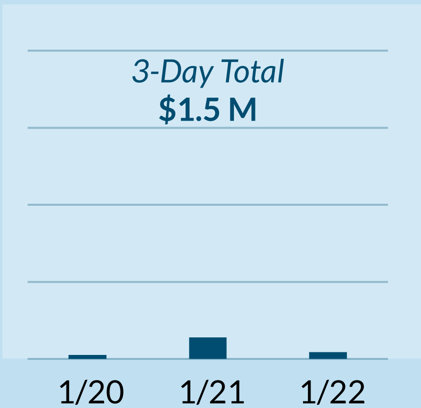
▼ ● ▼

ENZO

January 20-22, 2025
Martin Luther King Jr. Day

Temperature	6.5˚F
Peak Demand	108 GW
Renewable Output	19 GW
Incremental Outages	9 GW

*Uplift**



Unit Commitment Efficiency

■ ● ●

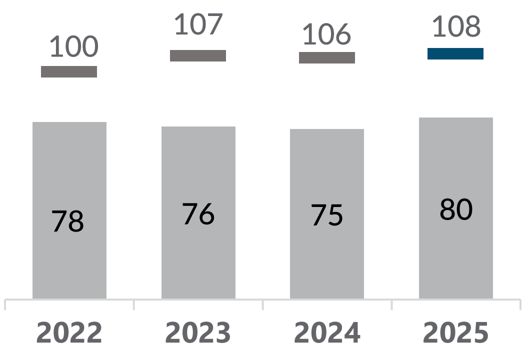
**Uplift is also known as revenue sufficiency guarantee (RSG)*

Unit Commitment Efficiency (2024 thresholds)

● Expected 91.5 % ■ Monitor 89.5 % ▼ Review 87.5 %

Reliability, markets and operational functions performed as expected this winter

AVERAGE AND PEAK LOAD (GW)



SYSTEMWIDE PEAK

108 GW

January 21

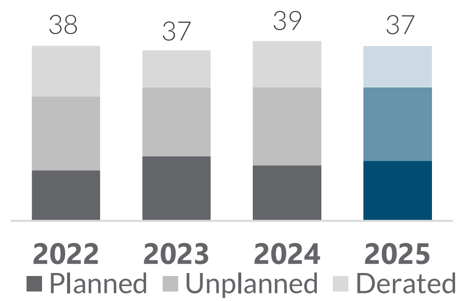
Winter Forecasted Peak: 100 GW

SOLAR PEAK

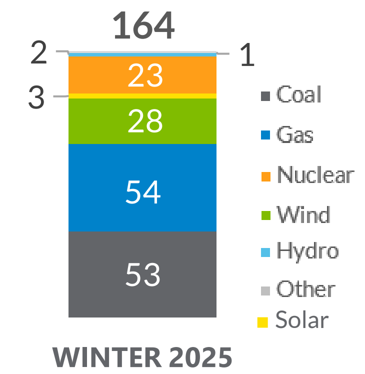
11.5 GW

February 21, Hour Ending 14

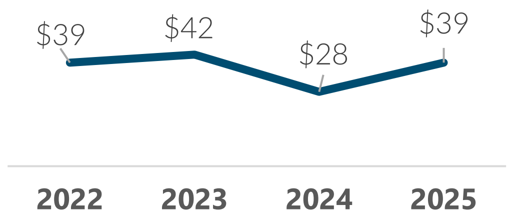
AVERAGE DAILY GENERATION OUTAGES (GW)



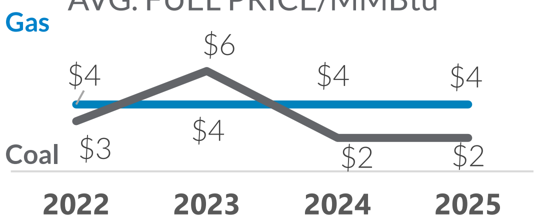
ENERGY FUEL MIX (TWh)



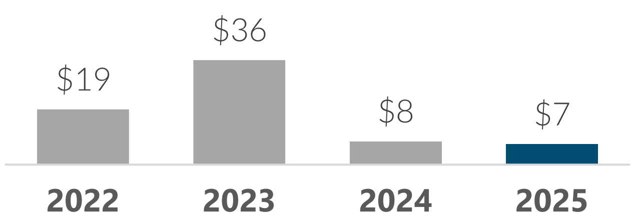
REAL-TIME LMP



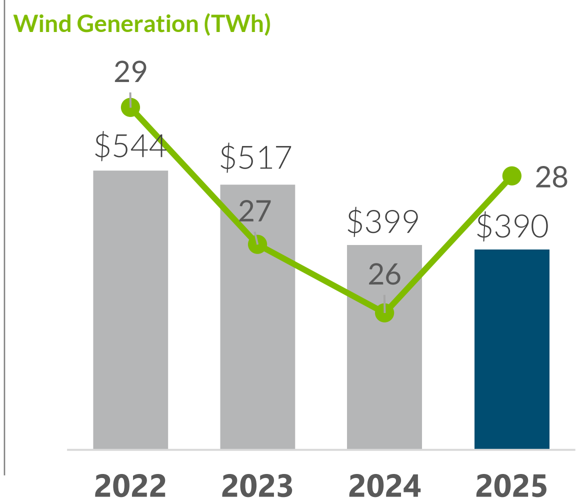
AVG. FUEL PRICE/MMBtu



REAL-TIME UPLIFT* PAYMENTS ($M)



REAL-TIME CONGESTION ($M)**



Data shown for winter (December-February) as of 2/25/25

**Uplift is also known as revenue sufficiency guarantee (RSG); uplift values may change due to resettlement*

*** Real-time congestion cost includes external constraints, data through 2/25/25*

Dashboard

Metric	STI	Jan '25	Dec '24	Nov '24	Oct '24	Metric	STI	Jan '25	Dec '24	Nov '24	Oct '24
MARKET EFFICIENCY											
Market Funding Efficiency Metric	*Excellent*	●	●	●	●	Unit Commitment Efficiency	*Excellent*	●	●	●	●
OPERATIONAL EXCELLENCE											
Control Performance – BAAL	*Excellent*	●	●	●	●	Control Performance – CPS1 and CPS1 12-month rolling	*Excellent*	●	●	●	●
Price Deviation		●	●	●	▼	Real-Time Obligation fulfilled by Day-Ahead Supply at the Peak Hour		●	●	●	●
Monthly Average Gross Virtual Profitability		●	●	●	●	Day-Ahead Wind Generation Forecast Error		●	●	●	●
FTR Funding		●	●	●	●	Day-Ahead Solar Generation Forecast Error		●	●	●	●
RSG per MWh to Energy Price		●	●	●	●	Tie Line Error		●	●	●	●
Day-Ahead Mid-Term Load Forecast		●	●	■	■	ARS Deployment		●	●	●	●
Short-Term Load Forecast		●	■	●	▼						
CUSTOMER SERVICE											
System Impact Study Performance		●	●	●	●	Settlement Disputes		●	●	●	●

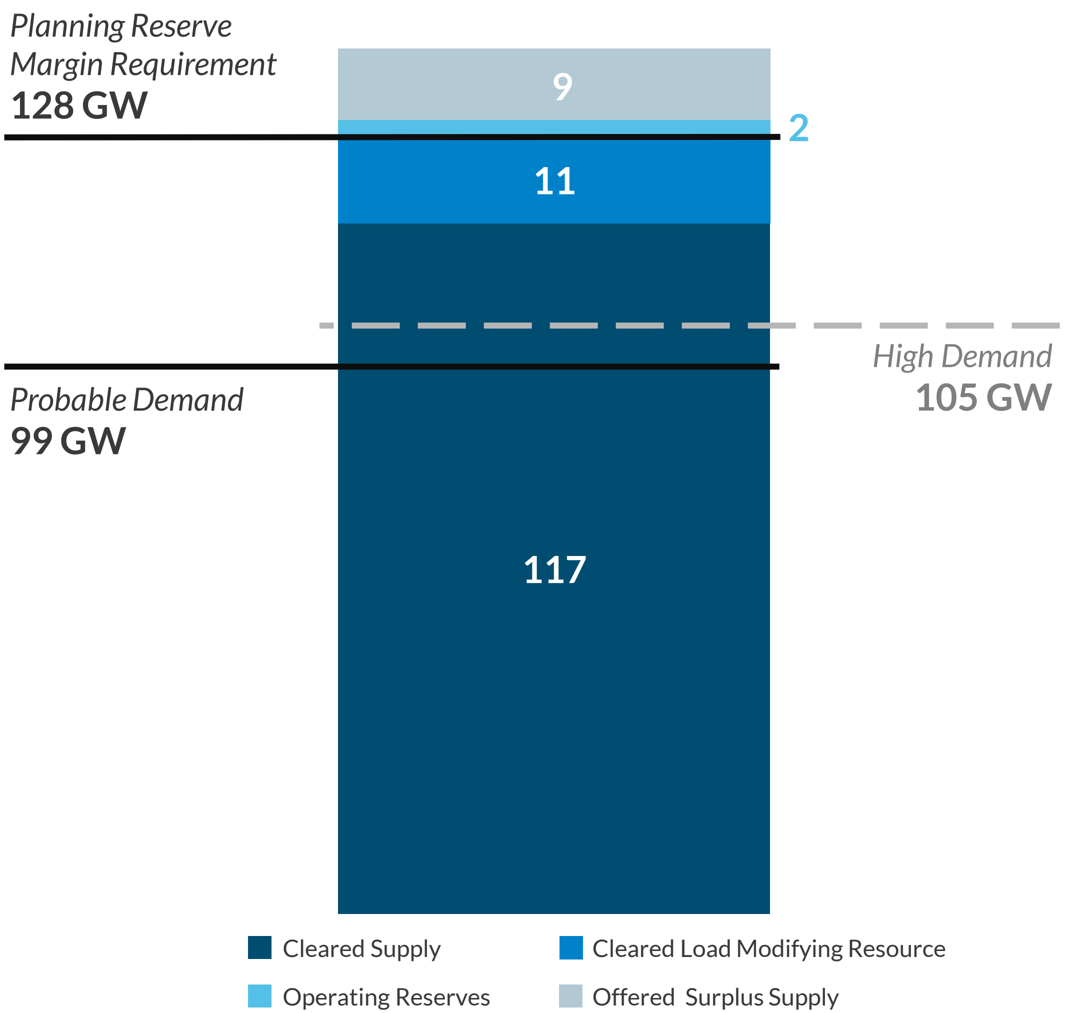
CLICK HERE to see MISO's monthly Operations Reports, which include the charts previously shared in the Appendix of this report

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

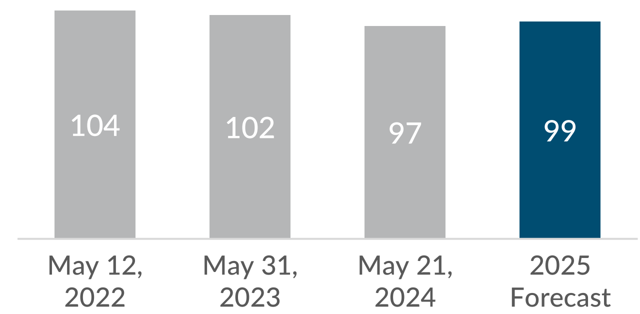
MISO

Spring 2025

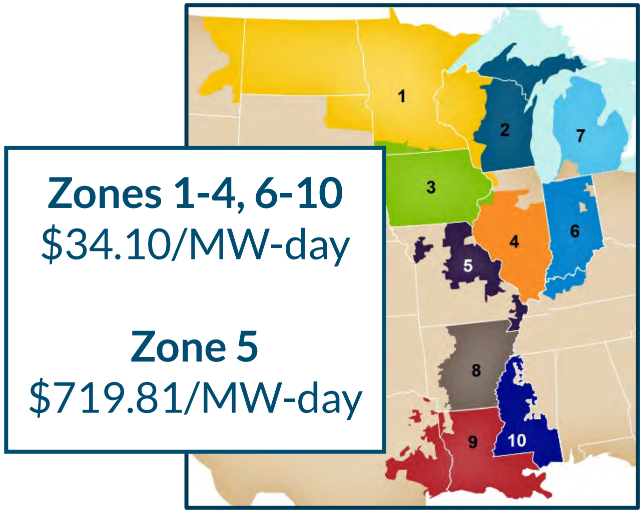
The MISO Seasonal Resource Adequacy Construct cleared sufficient resources to cover demand and projected uncertainty this spring



SPRING PEAK 2020 TO 2024 (GW)

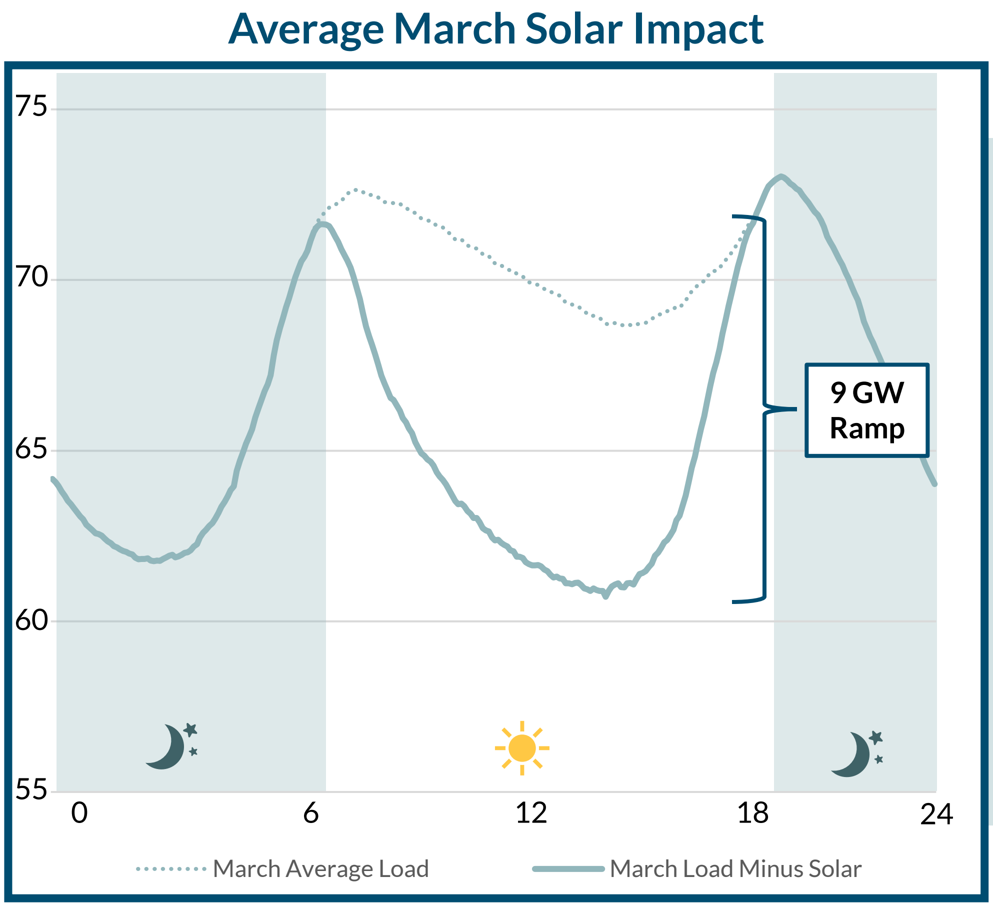


SPRING CLEARING PRICES



MISO

Ongoing congestion management process improvements have enabled MISO to better manage growing ramp requirements as increasing solar combines with existing wind generation



- Solar's quick increase in the morning and sharp decrease in the evening are already contributing to large uncertainties, impacting balancing and congestion management
- MISO is adjusting tools and processes, forecasts and reserve margin requirements to manage growing solar
- As more solar is added, MISO is preparing for new risks that fall outside of typical peak demand time

Appendix

MISO's Uncertainty Management Model continues to aid our operations in more confident and agile decision-making, resulting in efficient reliability

Uncertainty Management Model Process During Winter Storm Enzo – January 21

MISO's Uncertainty Management Model predicted high uncertainty for January 20-22

Successfully identified **January 21** as the day with the highest uncertainty

Forecast Uncertainty
HIGH (14.5 GW)

Based on the forecast uncertainty, MISO increased:

- Short-Term Reserve requirement to cover 99.7th percentile of risk
- Reserve margins

Actual Deviation**
HIGH (11 GW)

MISO Managed 11 GW of uncertainty in real-time due largely to unplanned generation outages

Despite high levels of actual deviation from the operating plan, MISO experienced positive outcomes

Uplift*
$1 Million

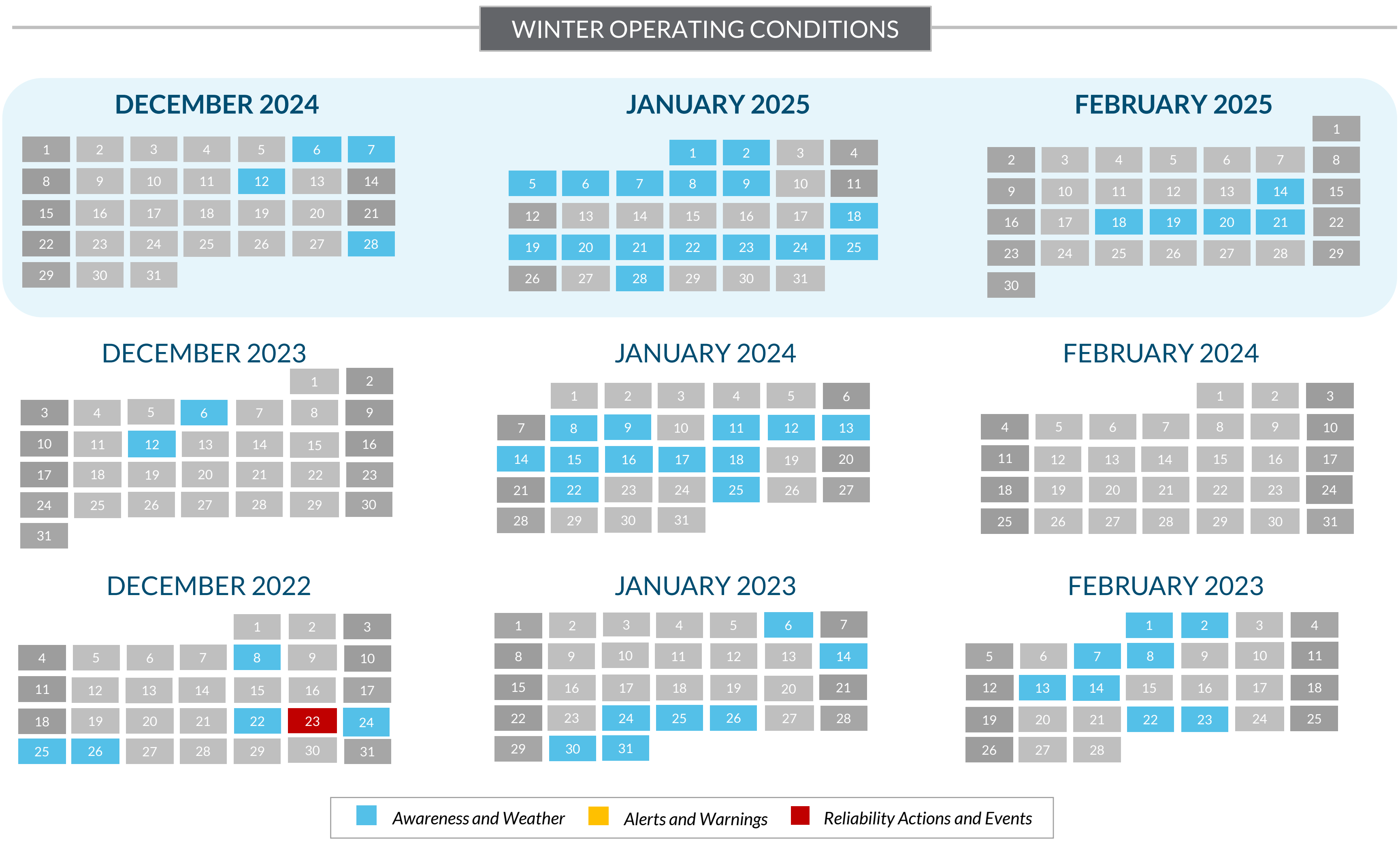
Unit Commitment Efficiency
93.4%

Uplift is also known as revenue sufficiency guarantee (RSG)

***The net load difference between the next-day operating plan and what occurs in real-time*

MISO

No reliability actions were needed this winter



Data shown for winter (December-February) as of 2/25/25

Details of Winter Operating Conditions

December 2024

- ***12/06 – North:*** *System Status Level 1*
- ***12/07 – North:*** *System Status Level 1*
- ***12/12 – North:*** *System Status Level 1*
- ***12/28 – South:*** *Severe Weather Alert*
- ***12/28 – South:*** *Conservative Operations*

January 2025

- ***1/01-1/02 – Footprint:*** *Conservative Operations*
- ***1/01-1/02 - Footprint:*** *Geomagnetic Alert*
- ***1/01 – Footprint:*** *Geomagnetic Warning*
- ***1/05 – South:*** *Severe Weather Alert*
- ***1/05-1/06 - Central:*** *Severe Weather Alert*
- ***1/06-1/09 - Footprint:*** *Cold Weather Alert*
- ***1/06-1/07 - South SEXTX:*** *Conservative Operations*
- ***1/06 – North****: System Status Level 1 (GRE)*
- ***1/18 – Footprint:*** *System Status Level 1 (ICCP outage)*
- ***1/19-1/22– Footprint:*** *Cold Weather Alert*
- ***1/20-1/22 - Footprint:*** *Conservative Operations*
- ***1/23 -1/25 – South & Central:*** *Cold Weather Alert*
- ***1/28 – Footprint:*** *System Status Level 1*

February 2025

- ***2/14 – Central & North:*** *Cold Weather Alert*
- ***2/18 – South:*** *Cold Weather Alert*
- ***2/19-2/21 – South:*** *Conservative Operations*

Data shown for winter (December-February) as of 2/25/25

One metric fell outside of the expected range for the season

Metric	Status	Comments
Short-Term Load Forecast	December Monitor	The Short-Term Load Forecast was in monitor due to non-conforming load.

CLICK HERE to see MISO's monthly Operations Reports

Data shown for winter (December-February) as of 2/25/25

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 143

NERC 2025–26 Winter Reliability Assessment

2025–2026 Winter Reliability Assessment

November 2025

Table of Contents

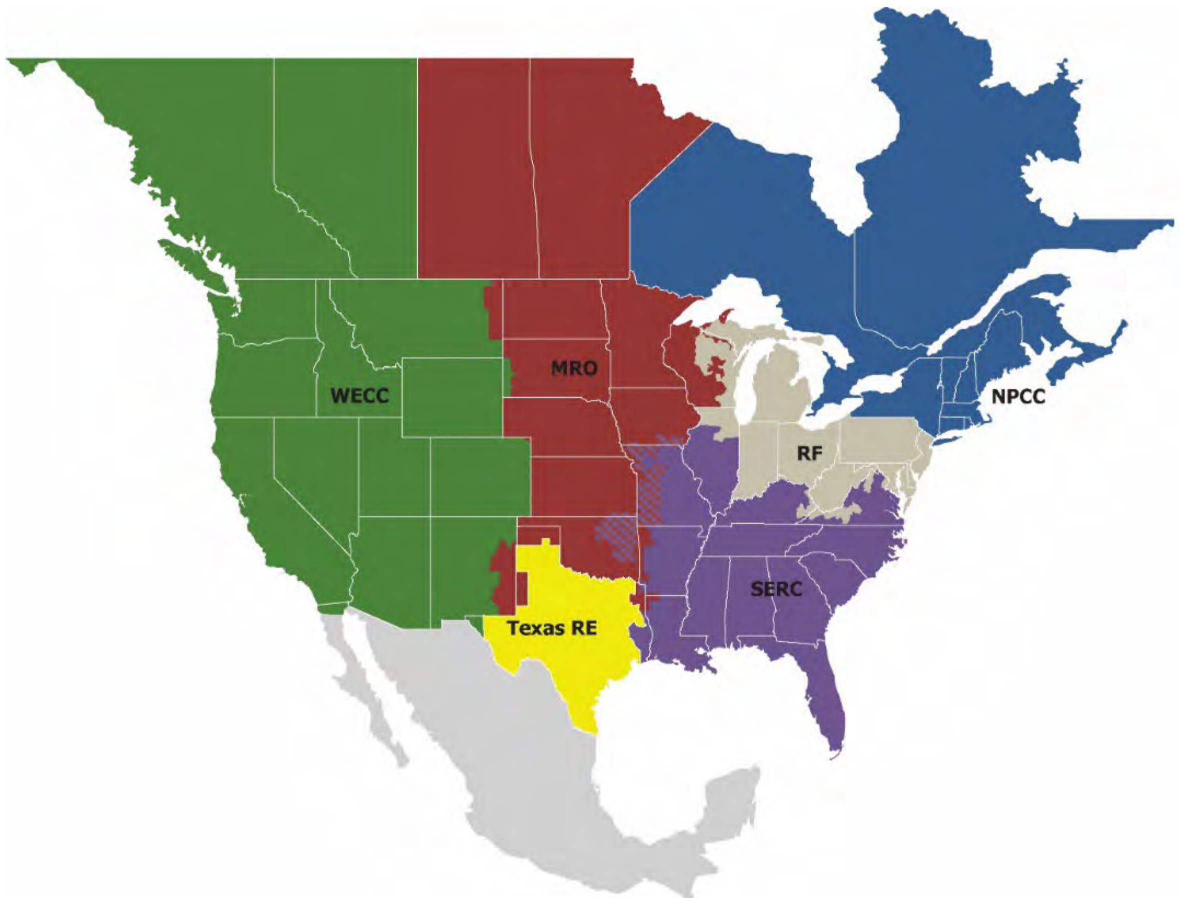
Preface

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 made up of six Regional Entities as shown in the map and 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	Western Electricity Coordinating Council

About this Assessment

NERC's *2025–2026 Winter Reliability Assessment* (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA 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 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 the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This WRA covers the upcoming three-month (December–February) winter period, providing an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter.

Two trends affecting resource adequacy across the BPS for the upcoming winter are rising electricity demand forecasts and a continued shift in the resource mix characterized by the retirement of thermal generators and growth in battery resources. After years of flat or low (~1%) peak demand growth, the aggregate peak demand for all NERC assessment areas has risen by 20 GW (2.5%) since the previous winter. Nearly all assessment areas are reporting year-on-year demand growth; some are forecasting increases near 10%. Total BPS resources have also increased since last winter, but by a smaller amount of 9.4 GW. This number includes the net change in generating capacity as well as additional demand response. These demand and resource changes are described in **Escalating Winter Demand** and **Resource Trends** sections.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operating concerns that should receive attention for Winter 2025–2026:

1. **All areas are assessed as having adequate resources for normal winter peak-load conditions (i.e., the area's 50-50 peak forecast). However, more extreme winter conditions extending over a wide area could result in electricity supply shortfalls.** Prolonged, wide-area cold snaps can drive sharp increases in electricity demand and threaten reliable BPS generation and the availability of fuel supplies for natural-gas-fired generation. Four severe arctic storms have descended to cover much of North America since 2021, causing regional demand for electricity and heating fuel to soar and exposing generation and fuel infrastructure in temperate areas to freezing conditions.[1] The following areas face risks of electricity supply shortfalls during periods of more extreme conditions this winter (see **Figure 1**):

   - **NPCC-Maritimes**: The peak demand forecast has fallen slightly (-1.6%) in the NPCC-Maritimes assessment area, contributing to higher reserves compared to the 2024–2025 winter. Maritimes is projected to have an Anticipated Reserve Margin (ARM) of 16.9%, which is 270 MW below the area's Reference Margin Level of 20% . New Brunswick has long-term energy contracts that can be used to mitigate resource adequacy challenges through the purchase of energy on a day-ahead basis. NPCC's all-hours probabilistic assessment for the NPCC Region included the simulation of both a base case (i.e., normal 50/50 demand) and highest peak load scenario (having an approximate 7% chance of occurring), for both an expected and a low-likelihood, reduced-resource condition. The preliminary results of this assessment indicate that operators in Maritimes are likely to require emergency operating mitigations and/or energy emergency alerts (EEA) during above-normal demand or low-resource output conditions.

   - **NPCC-New England**: A lower peak demand forecast and additional resources from demand response and firm imports offset recent generator retirements, resulting in little change to the NPCC-New England ARM for this winter. New England continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies. ISO-NE's deterministic winter scenario analysis shows limited exposure to energy shortfalls this winter. In New England, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods, timely replenishment is critical to minimizing the potential for energy shortfalls.

   - **SERC-East**: The winter peak demand forecast has increased by 700 MW (1.6%) since last winter, while winter firm capacity has declined, resulting in lower reserves. SERC-East has changed from a summer-peaking area to potentially peaking during both summer and winter. This is due to the continued addition of solar photovoltaic (PV) generation that shaves off summer peak demand and a trend toward electrification of heating that drives up winter peak demand. All-hours probabilistic analysis from SERC found some load-loss hours (<0.1 hrs) and small amounts of expected unserved energy, with the highest risk occurring during above-normal peak demand and early morning hours when solar output is absent.

   - **SERC-Central:** Additional demand response and flat load growth since last winter is offsetting declining resource capacity (down 1,120 MW), resulting in little change to the ARM at 30.5%. There are adequate resources for normal winter peak demand; however, higher levels of demand that can occur during extreme cold temperatures can result in insufficient reserves that operators would need to manage with non-firm imports and potential energy emergencies.

   - **Texas RE-ERCOT:** Strong load growth from new data centers and other large industrial end users is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For the upcoming winter season, Texas RE-ERCOT is expected to continue facing reserve shortage risks during the peak load hour and high-

[1] See detailed reports on the January 2024 and January 2025 Arctic Storms, Winter Storm Elliott, and Winter Storm Uri.

net-load hours, particularly under extreme load conditions that accompany freezing temperatures. Elevated forced outage of thermal resources and reduced output from intermittent resources during these conditions exacerbates the risk of supply shortfalls. In winter, peak demands typically occur before sunrise and after sunset coinciding with the unavailability of solar generation making the system dependent on wind generation and dispatchable resources. Data centers are altering the daily load shape due to their round-the-clock operating pattern, lengthening peak demand periods. Additional battery storage and demand-response resources since last winter help mitigate shortfall risks. However, with the continued flattening of the load curve, maintaining sufficient battery state of charge will become increasingly challenging for extended periods of high loads, such as a severe multi-day storm like Winter Storm Uri.

- **WECC-Basin**: There is sufficient capacity in the area for expected peak conditions; however, Balancing Authorities (BA) are likely to require external assistance during extreme winter weather that causes thermal plant outages, adverse wind turbine conditions, and natural gas fuel supply issues for area internal resources. External assistance may not be available during region-wide extreme winter conditions. With an expected winter peak demand of 11.1 GW, under an extreme combination of generator derates and outages, the region could be short 1.6 GW before imports. Forecasted net internal demand has increased 1% since last year, with little change in winter capacity. Note that the WECC-Basin assessment area includes Utah, southern Idaho, and a portion of western Wyoming. In prior WRA reports, this part of the BPS was included as part of the WECC-NW assessment area. The *2025–2026 WRA* 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.
- **WECC-NW**: Like WECC-Basin, there is sufficient capacity in the area for expected peak conditions; however, BAs are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year. Over 3 GW of new resources have been in development for the assessment area this year, primarily battery storage, solar PV, and wind resources. Delays that threaten timely completion of these resource additions will make the area more reliant on imports to meet peak demand.

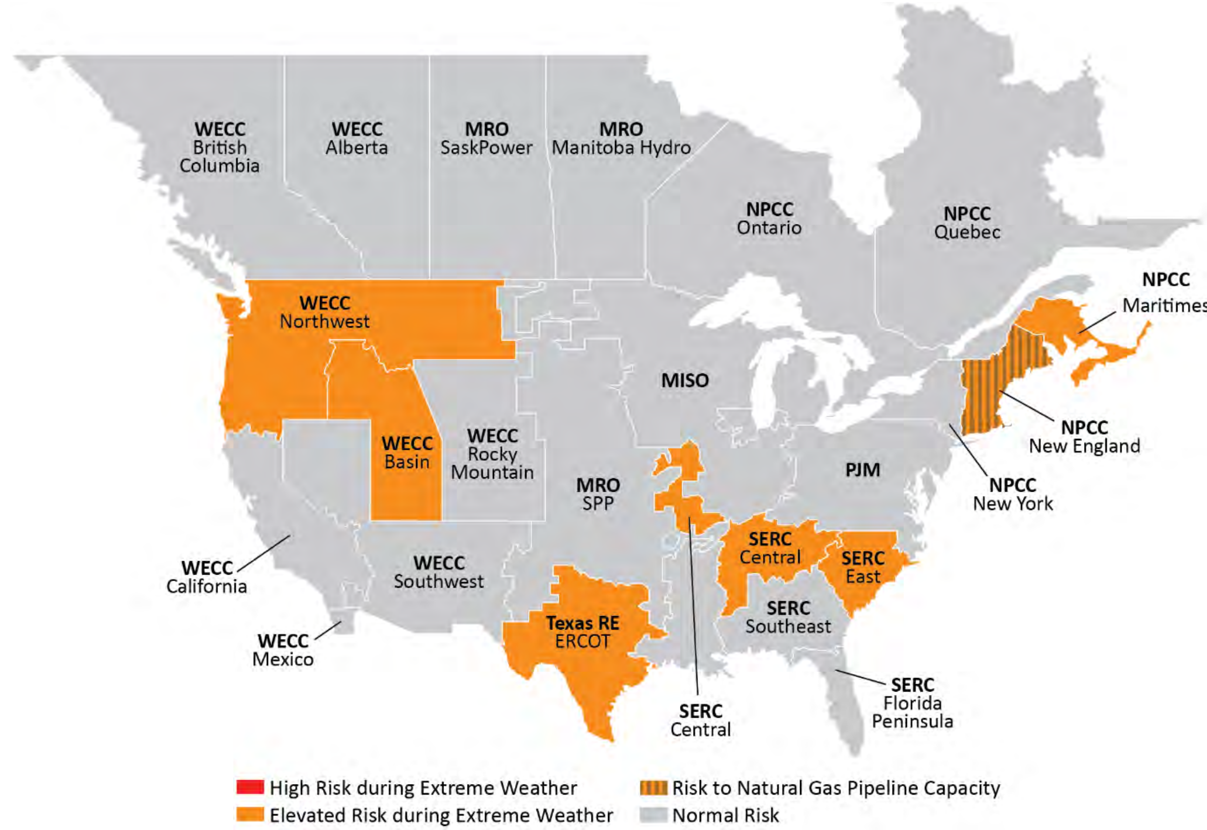


Figure 1: Winter Reliability Risk Area Summary

2. **The performance of natural gas production and supply infrastructure during peak winter conditions will again have a significant effect on BPS reliability.** Natural gas is an essential fuel for electricity generation in winter. Winter fuel supplies for thermal generators must be readily available during the periods of high electricity and natural gas demand that accompany extreme cold weather. Yet these periods are the most challenging for natural-gas-fired Generator Operators to obtain sufficient fuel and delivery. Natural gas production often falls off in extreme winter temperatures as supply infrastructure is affected by freezing issues, and Generator Operators that fail to secure firm fuel delivery are frequently unable to access fully subscribed pipelines. Evidence from the past two winters indicates notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure

force majeures.[2] Still, natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, resulting in uneven application of protections and continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends. As winter approaches, NERC encourages all entities across the gas-electric value chain—from production to the burner tip—to take all necessary preparations for extreme cold and keep natural gas flowing and the lights on.

3. **Cold weather Reliability Standards first introduced in 2023 have been improved prior to the upcoming winter and address recommendations from winter storms Elliott and Uri.** In September 2025, the Federal Energy Regulatory Commission (FERC) approved EOP-012-3 with an effective date of October 1, 2025, concluding the development of Reliability Standards for generator cold weather preparedness.[3] The EOP-012 Reliability Standard contains requirements for generator freeze protection measures, cold weather preparedness plans, and operator training. Among the improvements in the new version are enhanced and expanded requirements to ensure that Generator Owners (GO) are implementing corrective actions to address known issues affecting their ability to operate in cold weather in a timely manner. NERC collects data on the winterization of generating units, which, in conjunction with NERC's monitoring of BPS performance and analysis of cold weather events, helps determine the effectiveness of Reliability Standards. NERC submitted to FERC its first annual *Cold Weather Data and Analysis* informational filing in October 2025.[4] Based on the data reported this year, 96% of the total net winter capacity reported extreme cold weather temperatures (ECWT) at or below 32 degrees Fahrenheit, triggering winter preparedness measures under the Cold Weather Preparedness Standard, and 99% of total net winter capacity in the continental US reporting the ability to operate at the calculated ECWT. As the first such report, this *Cold Weather Data and Analysis* filing provides a benchmark for future analysis.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- Reliability Coordinators (RC), BAs, and Transmission Operators (TOP) in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should review NERC's Resources on Cold Weather Preparations.
- GOs should complete winter readiness plans and checklists prior to December, deploy weatherization packages well in advance of approaching winter storms, and frequently check and maintain cold weather mitigations while conditions persist.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies. Proactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- Generator Owners/Operators of natural-gas-fired units should maintain awareness of potential extreme cold weather developing over holiday weekends and the implications for fuel planning and procurement that may result given the natural gas purchase close dates that precede long holiday weekends.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by maintaining awareness of BA, natural gas pipeline, and gas local distribution company (LDC) operational public announcements and notices, amplifying public appeals for electricity and natural gas conservation, and supporting requested environmental and transportation waivers.

[2] See *January 2025 Arctic Events | A System Performance Review*, April 2025
[3] See NERC's Statement on FERC September Open Meeting for summary and link to FERC's order.
[4] See 2025 Cold Weather Data Collection and Analysis Informational Filing

Risk Highlights

Escalating Winter Demand

Winter electricity demand is rising at the fastest rate in recent years, particularly in areas where data center development is occurring. After several years of low (~1%) growth, total internal demand for the BPS is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. The changes in forecasted net internal demand for each assessment area are shown in **Figure 2** below.[5] Assessment areas develop these forecasts based on historical load and weather information as well as future projections. Most assessment areas are projecting an increase in peak demand. SaskPower, PJM, the U.S. Southeast, and parts of the U.S. West have the largest increase in peak demand forecasts.

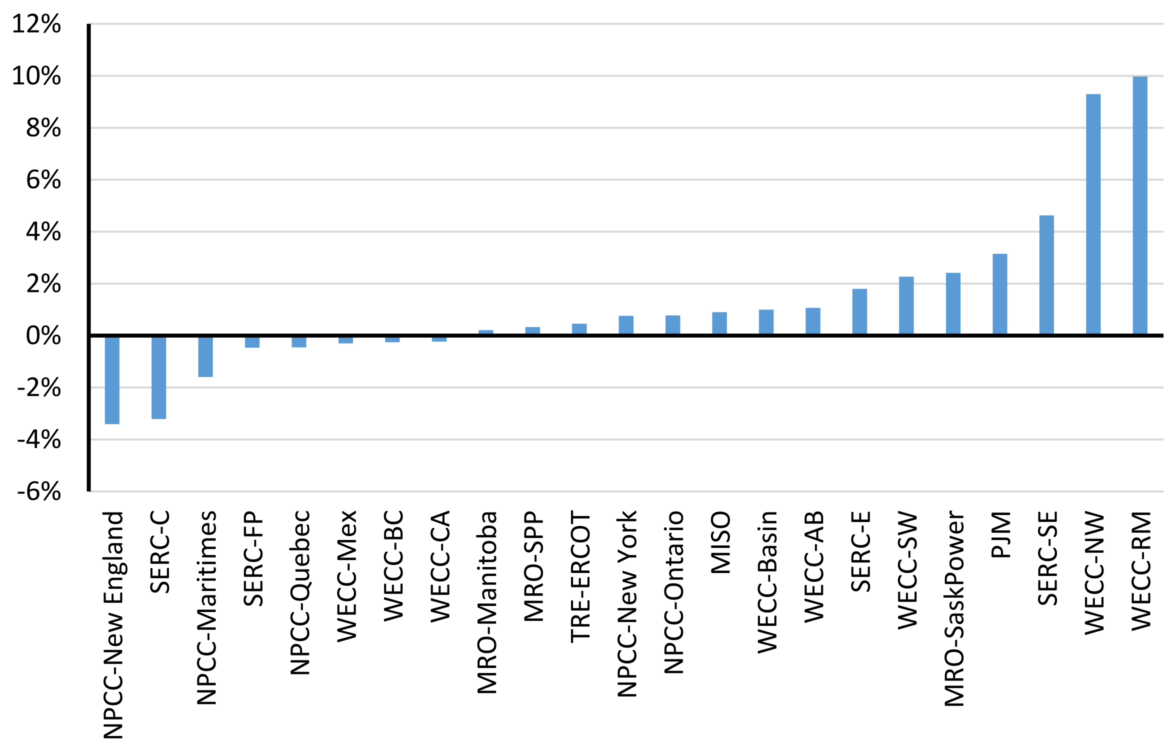


Figure 2: Change in Net Internal Demand—Winter 2025–2026 Forecast Compared to Winter 2024–2025 Forecast

[5] See **Data Concepts and Assumptions** section for demand definitions.

Resource Trends

BPS resources are growing, but at a slower rate than demand is rising. Battery and solar facilities were the leading resource types added to the BPS since last winter. Solar resources, however, often do not supply output during hours of peak winter demand. Growth in demand response is also contributing to BPS resources for the upcoming winter. **Table 1** shows the total change in BPS resources since last winter. For battery, solar, and wind resources, the table includes change in both nameplate (installed) capacity as well as the change in on-peak demand capacity, which is the capacity that resources are expected to provide in their area during the time of peak demand. For assessment-area specific information see **Variable Energy Resource Contributions** section.

Table 1: BPS Resource Change from Winter 2024–2025 to Winter 2025–2026

Resource	Net Change Nameplate Capacity (MW)	Net Change Peak Demand Capacity (MW)
Total Generator Capacity		1,335
Battery	19,659	11,121
Solar	11,097	1,176
Wind	-562	-14,238
Thermal and Hydro		3,276
Demand Response		8,112
Total Resources		9,447

Total BPS resources for serving winter peak demand, including generating capacity and demand response, have increased since last winter by 9,447 MW. Sizeable additions in battery resources and some new natural gas-fired generators contribute to the increase in resource capacity. However, the increase is offset by lower on-peak capacity values for wind resources, which are the result of revised valuations of wind resource capability at peak demand hours in some areas.[6] As a result, BPS generator capacity for winter peak demand makes up only a small portion of the total BPS increase. Generation accounts for 1,335 MW of the total 9,445 MW increase, while the larger share comes from demand response programs. Area specific information on demand response is provided in the **Demand and Resource Tables**.

The recent trend in resource additions is contributing to higher risk of electricity supply shortfalls in winter. BA operators are likely to face higher winter demand without a comparable increase in supply resources. Furthermore, the types of resources that are growing the most-- battery resources and

[6] Since last winter, ERCOT and MISO have implemented new methods for determining capacity contributions that result in lower wind and solar resources contributions at peak demand. See ERCOT's Resource Adequacy page and MISO's *Planning Year 2025-2026 Wind and Solar Capacity Credit Report*.

demand response—have unique characteristics that operators will need to account for and could limit the use of these resources in extreme winter conditions. Battery energy is reliable when it can be dispatched and has sufficient charge for the period it is needed, yet little time to recharge can be expected during extreme winter weather. System operators will need good visibility on battery state of charge and should anticipate that some extreme winter events will cause these resources to become depleted when needed. Demand response is limited by contract terms, which typically specify how often and for how long the resource may be used. Other resource types are also challenged in winter (see **Thermal Generator Fuel Adequacy and Security**). As BAs grapple with higher demand in most parts of the BPS, they will do so with resources that are becoming increasingly complex to dispatch especially in winter.

Thermal Generator Fuel Adequacy and Security

The performance of the thermal generator fleet remains critical to winter BPS operations. Winter fuel supplies for thermal generators must be readily available during periods of high demand and extreme cold weather. Generally, fuel adequacy for the thermal generating fleet is bolstered through strategic infrastructure investments and fuel stockpiling that increases the certainty of having fuel on hand that can be converted to electricity when needed. Because of this, winter performance of thermal generators is inextricably linked to extraction, processing, storage, and delivery infrastructure for a variety of fuels. Fuel supply risks have been noted in recent years' WRAs related to coal and natural gas availability and illustrate the interconnected nature of these critical energy infrastructure systems.

BPS stakeholders across North America note multiple fuel-related issues that are being monitored entering the winter season. For example, while coal represents a waning share of the overall resource mix, it continues to play an important role in meeting demand during extreme winter weather events, and oil inventories at dual-fuel gas-oil generators lessen risks related to natural gas deliverability in infrastructure-constrained regions, especially during the winter. Notably, it is infeasible or prohibitively costly to stockpile natural gas locally at power plants, and this exposes the BPS to the risk profile of the constituent systems that comprise the supply and delivery of this just-in-time fuel.

Natural Gas Generator Fuel Supplies

Natural gas generators remain a crucial part of on-peak resources meant to meet winter electricity demand across much of North America. While many Generator Owners and Operators secure backup fuel supplies at critical gas-fired generators, particularly in the northeastern United States and Florida, large contributions to the on-peak winter resource mix by single-fuel natural-gas-fired generators remain across North America (see **Figure 3**).

Natural gas generator performance can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel to critical generators. Grid operators continue to acknowledge and enhance their winter planning processes to firm up their fuel supplies and guard against natural gas disruptions, but winter storms Uri and Elliott demonstrated that combinations of natural gas flow restrictions and supply insufficiency can occur regardless of whether cold temperatures are common or uncommon in the region and can affect more than one BA area concurrently.

Many BPS areas that regularly experience cold weather events, like New England, have adopted mitigating technologies to lessen the impact of natural gas shortages through generator dual-fuel capability and stored backup fuel. In those areas, prolonged cold weather events present a risk of rapid depletion of stored backup fuel. Robust regional and distributed storage investments and winter planning for timely fuel replenishment are critical to minimizing potential energy shortfalls in the operational time frame in these areas.

Natural gas and electricity infrastructures have the added complexity of interdependence. Electricity is used to power some facilities, such as compressor stations and processing plants that make up natural gas infrastructure. These interdependencies mean that reliability events that originate on one system have the potential to affect the other and worsen the overall event magnitude or duration.

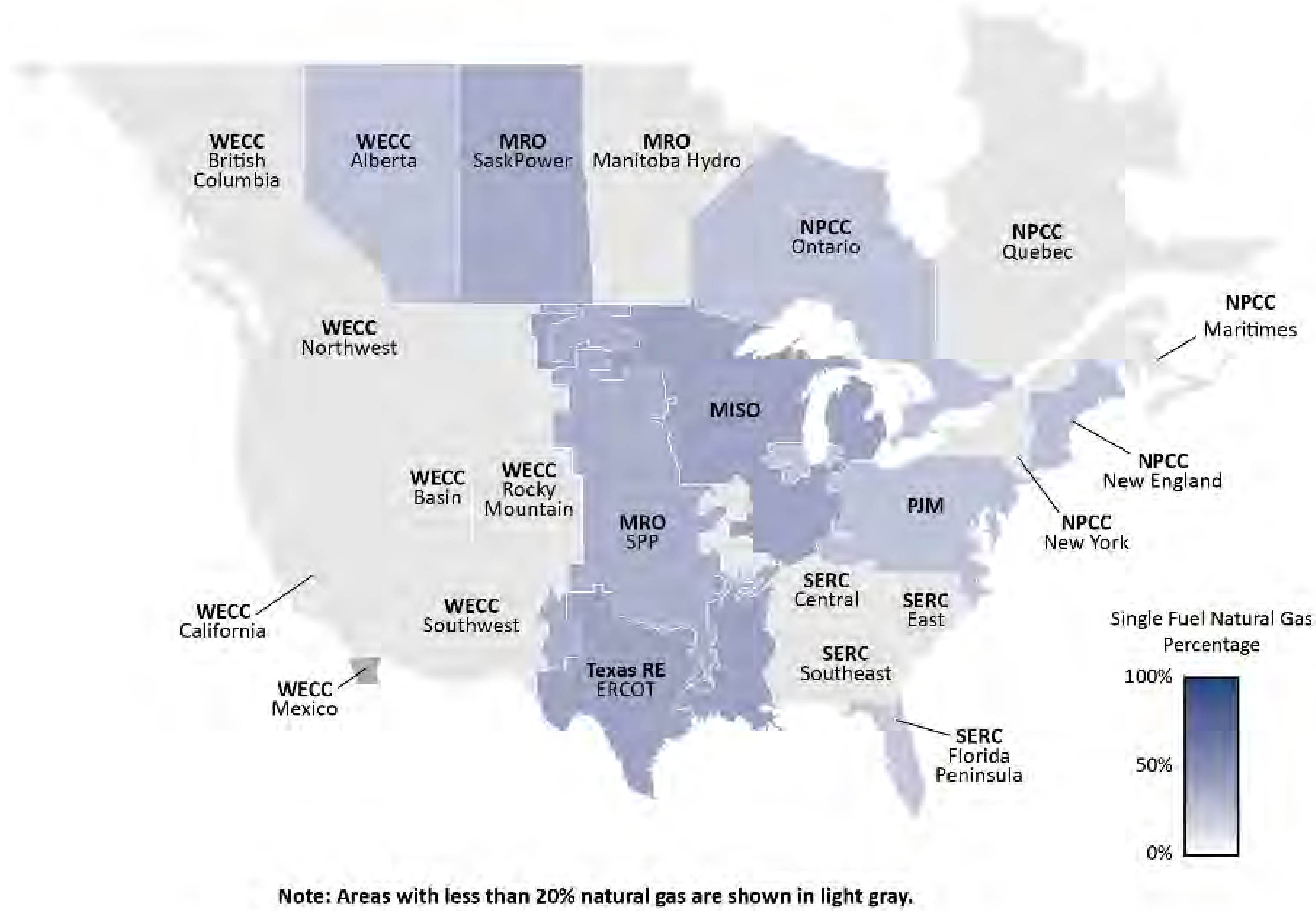
Natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America. Texas is an exception, where the Railroad Commission of Texas adopted rules to require critical natural gas facilities to implement weather-related emergency preparation measures.[7] Lack of consistent standards for natural gas infrastructure protections will result in uneven application of freeze protections and continued supply risks during extreme conditions in many areas.

These considerations have driven higher levels of coordination to ensure sustained reliable operation of the natural gas and electricity systems. While a FERC and ERO staff review of system performance during the January 2025 arctic events[8] details improvements in electric and natural gas coordination since winter storms Uri and Elliott, the review also identifies continuing gaps between the electricity and natural gas industries that remain entering the 2025–2026 Winter season. These include natural gas scheduling challenges during winter holiday weekends, market time frame and process incompatibility, and electric power entities' lack of visibility into operational impact data from natural gas producers and suppliers.

[7] See Railroad Commission of Texas weatherization rule.

[8] FERC, NERC Issue Report on System Performance During the January 2025 Arctic Weather | Federal Energy Regulatory Commission

The U.S. Energy Information Administration (EIA)[9] anticipates a slightly milder winter than last year across much of the United States, especially in the Northeast, leading to a projection that households will consume approximately 2% less natural gas than last winter. Working natural gas storage inventories are about 5% above the previous five-year average in the United States heading into the winter season. The EIA attributes this relative surplus in part to robust production this summer and lower-than-expected natural gas consumption by power generators.



Single-Fuel Natural-Gas-Fired Generation

	Winter Capacity (GW)	Contribution to Total Winter Resource Mix
MISO	63.9	38%
TRE-ERCOT	53.0	38%
WECC-MX	2.2	34%
MRO-SaskPower	2.5	34%
SPP	33.4	32%
NPCC-New England	12.1	24%
PJM	60.9	23%
WECC-AB	13.9	23%
NPCC-Ontario	8.0	23%
SERC-FP	45.6	21%
WECC-CA	35.9	18%
WECC-SW	21.5	17%
WECC-Basin	4.9	16%
WECC-RM	6.2	14%
SERC-C	17.0	13%
SERC-SE	21.5	13%
WECC-NW	8.7	12%
SERC-E	11.3	9%
NPCC-New York	5.0	8%
NPCC-Maritimes	0.5	7%
MRO-Manitoba	0.3	4%
WECC-BC	0.1	1%
NPCC-Quebec	0.0	0%

Figure 3: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the 2025–2026 Winter Generation Mix

[9] See the U.S. Energy Information Administration's Winter Fuels Outlook 2025–26

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 2**.

Table 2: 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 (RML); or • Probabilistic indices exceed benchmarks, e.g., loss of load hours (LOLH) of 2.4 hours over the season; or • 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); or • 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] or • 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 (ARM), which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins with typical forced outage levels and for the most extreme seasonal risk scenarios are provided in **Table 3**.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Reserve Margin with Typical Outages	Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	49.5%	22.3%	3.7%
MRO-Manitoba	13.7%	11.4%	6.1%
MRO-SaskPower	35.1%	29.0%	16.1%
MRO-SPP	56.5%	29.4%	16.9%
NPCC-Maritimes	16.9%	12.5%	-4.7%
NPCC-New England	58.9%	45.4%	8.7%
NPCC-New York	78.2%	52.4%	16.2%
NPCC-Ontario	28.6%	21.8%	13.2%
NPCC-Québec	15.2%	15.1%	5.0%
PJM	35.6%	24.8%	15.6%
SERC-C	30.5%	22.4%	-0.9%
SERC-E	21.9%	17.5%	3.0%
SERC-FP	41.7%	28.3%	25.6%
SERC-SE	39.7%	24.7%	17.7%
TRE-ERCOT	36.0%	25.2%	-20.0%
WECC-AB	35.2%	32.4%	10.0%
WECC-Basin	29.6%	19.7%	-21.1%
WECC-BC	25.9%	25.8%	15.4%
WECC-CA	82.3%	73.7%	57.9%
WECC-Mex	83.1%	79.4%	52.9%
WECC-NW	30.9%	29.5%	-8.5%
WECC-RM	61.7%	53.2%	10.0%
WECC-SW	104.4%	90.1%	50.1%

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 winter 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 3**, each assessment area's ARMs 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.

Areas highlighted in orange in **Figure 1** above have been identified as having resource adequacy or energy risks for the winter and are included in the **Key Findings** section's discussion that follows. 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 ARM, 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 winter season. Results are summarized in **Table 5**. 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 loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) declarations (see **Table 4** for a description of EEA levels).

Table 4: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	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 operating reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	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 operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Energy Emergency Alerts

The combination of above-normal generation outages, low resource output, and peak loads as occurred during the extreme cold weather events of Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 are ongoing winter reliability risks. When supply resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ EEAs to maintain balance between available capacity and energy and real-time demand. A description of each EEA level is provided above.

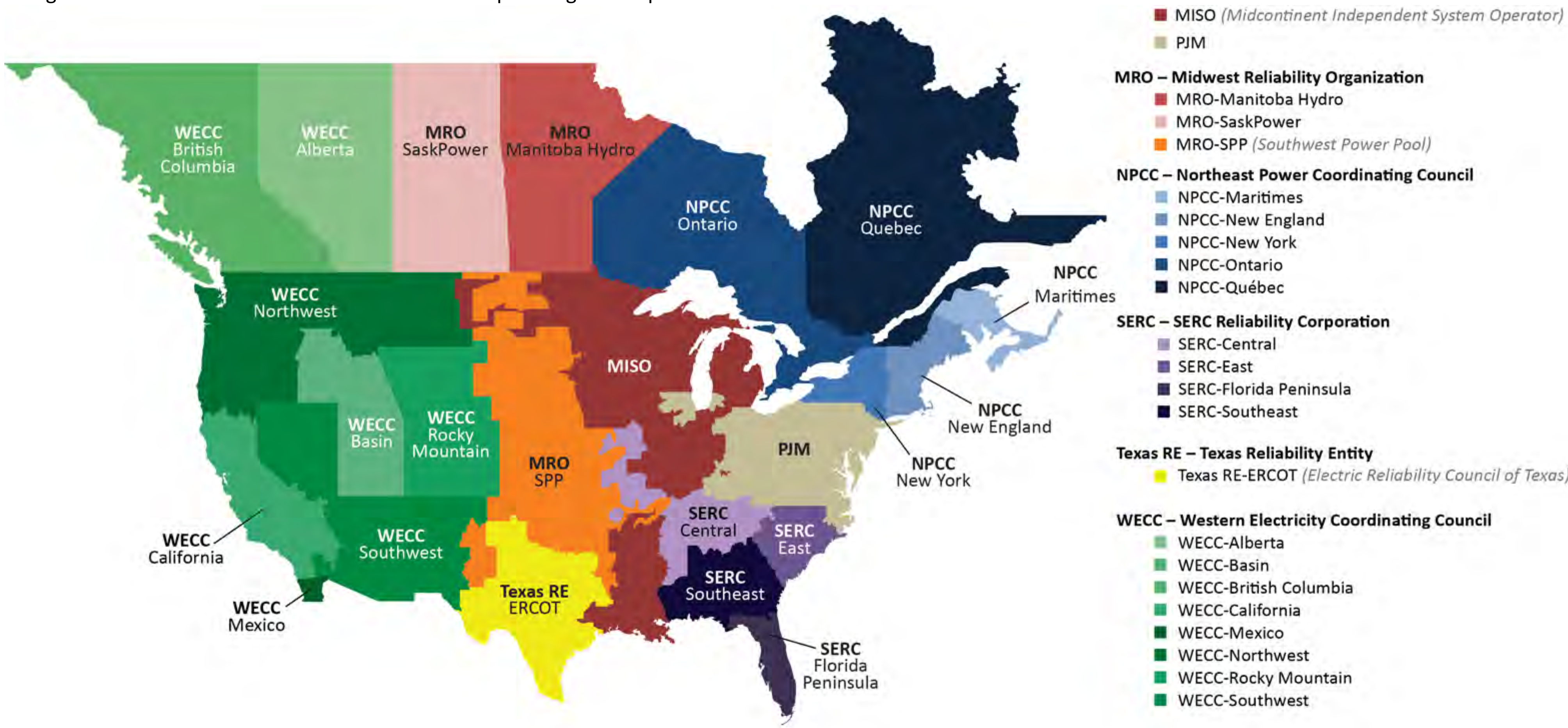
Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Deterministic	MISO does not provide a probabilistic assessment for the WRA. MISO applies a deterministic look at expected system conditions, looking at generation availability under typical and extreme outages and looking at a typical 50/50 load forecast and an extreme 90/10 load forecast. For the upcoming winter season, under an extreme outage and extreme 90/10 load forecast, this is the riskiest scenario for the MISO footprint. This scenario produces the shortest actual reserve margin for January.
MRO-Manitoba	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 *Long-Term Reliability Assessment* (LTRA) found no load-loss or unserved energy hours for 2026.
MRO-SaskPower	Probability-based capacity adequacy assessment	SaskPower's probabilistic assessment for the 2025–2026 Winter indicates that risk of shortfalls is lower than the previous winter. LOLH for an elevated risk scenario for the 2025–2026 Winter season is 0.08 hours. The month with the highest LOLH is December (0.05 hours).
MRO-SPP	NERC 2024 ProbA	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that included detailed neighbor modeling and consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The assessment evaluates the probabilistic indices of LOLE, LOLH, and EUE. The highest peak load scenario has an approximately 7% probability of occurring.	
NPCC-Maritimes	The Maritimes Area low-likelihood resource case assumed: wind derated by 50% for every hour in December through February and a 50% natural gas capacity curtailment for December through February (dual-fuel units assumed reverting to oil) and reduced transfer capabilities.	The preliminary assessment indicates that established operating procedures are not sufficient to maintain a balance between electricity supply and demand. Under highest peak load levels, the Maritimes Area shows a notable likelihood of utilizing its operating procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves to maintain system reliability during the upcoming winter period.
NPCC-New England	The New England Area low-likelihood resource case assumed: 500 MW of additional maintenance outages, ~4,513 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand
NPCC-New York	The New York Area low-likelihood resource case assumed: ~500 MW of extended maintenance in southeastern New York, 600 MW of cable transmission reduction across HVdc facilities, and ~5,000 MW of generation unavailable due to fuel delivery issues.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.
NPCC-Ontario	An energy assessment for the Ontario Assessment Area was conducted for two scenarios: firm resources and firm demand with expected weather, and planned resources with planned demand with expected weather.	No cumulative LOLH or EUE risks were identified over the entire November-to-April winter season for both scenarios modeled.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Québec	The Québec Area low-likelihood resource case assumed 1,000 MW of generation reductions.	The preliminary results of this assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand if needed. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period for all the scenarios modeled
PJM	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic study for 2025–2026 Winter is not provided for the WRA. PJM performed probabilistic analysis for 2026-2027 winter as part of the 2024 ProbA summarized in NERC's 2024 LTRA. The results of this study indicate risk of load loss (<0.1 hours) and unserved energy during winter months. For the upcoming winter, load-loss hours are expected to be less than this value because forecasted load is lower and anticipated resource capacity is higher than the case studied for the 2024 ProbA.
SERC	Based on the 2024 NERC Probabilistic Assessment (ProbA) base-case result. SERC's assessment used 38 years of historical load shapes to assess the resource adequacy of years 2026 and 2028, primarily based on data from the 2024 Long Term Reliability Assessment (LTRA).	
SERC-Central		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
SERC-East		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found a small number of load-loss hours (<0.1) and EUE (61 MWh / 1 ppm) for 2026.
SERC-Florida Peninsula		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found negligible load-loss hours and EUE.
SERC-Southeast		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
WECC	The resource adequacy work performed at WECC used the Multi-Area Variable Resource Integration Convolution (MAVRIC) model for the 2025 LTRA. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and ProbA.	
WECC-AB		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Basin		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-BC		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-CA		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Mexico		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Rocky Mountain		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-NW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026. Results for a case where new resource additions are not completed for the upcoming winter found some EUE and LOLH.
WECC-SW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

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 ARM compared to a reference margin level (RML) that is established for each area 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 two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme winter 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 WRA 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 vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.



MISO

The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations as well as energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 Local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 77,000 miles of transmission lines and approximately 1,888 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

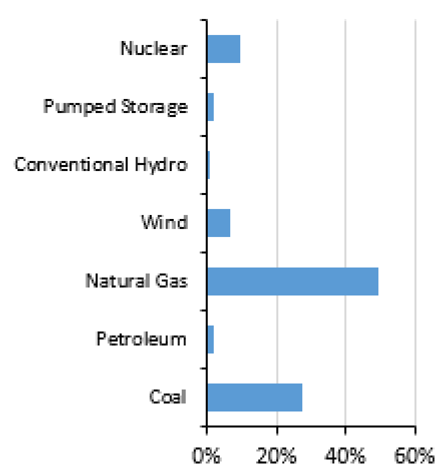
- MISO expects limited risk in the 2025–26 Winter season as MISO was able to procure 6.1% more resources through the annual planning reserve auction than required by its minimum resource adequacy target. A further 3.3 GW of resources were available but not chosen to be committed for the winter season.
- Some risk has been identified for this upcoming winter season. In a high generation outage and high winter load scenario reliability is expected to be maintained by reliance upon operational mitigations that include non-firm energy transfers into the system, energy-only resources not subject to a must-offer requirement that may still offer into the energy markets, load-modifying resources, and internal transfers that exceed the Sub-Regional Import/Export Constraint (SRIC/SREC) between the MISO North/Central and South areas.
- MISO continues to coordinate with neighboring RCs and BAs to improve situational awareness and vet any needs for energy transfers to address extreme system conditions.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency.
- MISO has implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.

On-Peak Reserve Margin[10]

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with generator outages from freezing or fuel supply issues and low wind output result in the need to employ operating mitigations (i.e., demand response and transfers).

On-Peak Resource Mix



2025–2026 Winter 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 net internal demand and additional demand during extreme weather conditions (e.g., Winter Storm Enzo) using member submitted data and historical load data

Typical Maintenance Outages: Rolling three-year winter average of peak-day maintenance and planned outages

Typical Forced Outages: Three-year average of all peak-day outages that were not planned

Resource Derates for Extreme Conditions: Represents derates aligning with the most extreme hour of each of the past 3 years,

Operational Mitigations: Non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement, or internal transfers that exceed the SRIC/SREC between the MISO North/Central and South regions

[10] The MISO Risk Scenario Assessment for the 2025-26 Winter Season is not directly comparable to that for the 2024-25 Winter Season as methodology improvements have been implemented.

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 Balancing Authority (BA). Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

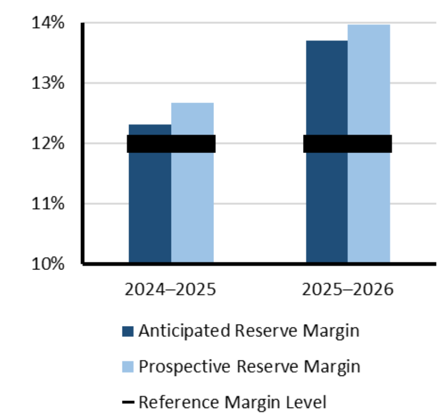
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Winter 2025–2026.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even under continued drought conditions.
- Manitoba Hydro is experiencing well below-average water supply conditions; however, the Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought.
- The ARM for Winter 2025–26 exceeds the 12% RML.

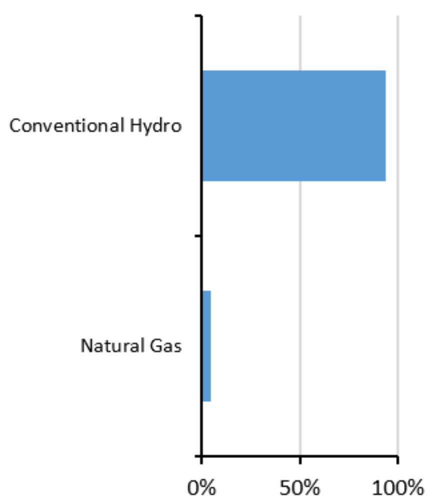
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

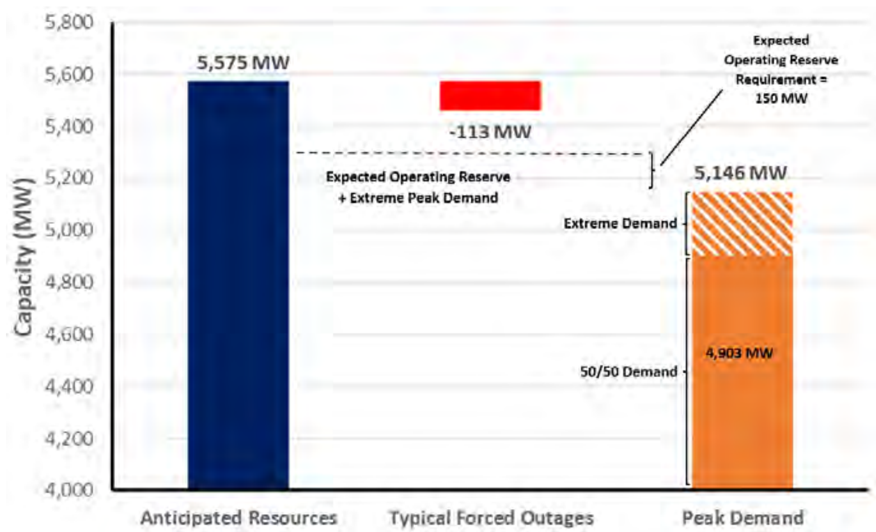
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 weather data

Typical Forced Outages: Accounts for average forced outages

MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. 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 Bulk Electric System (BES) and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

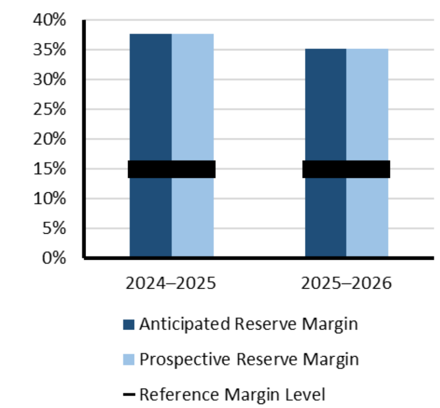
Highlights

- Saskatchewan experiences its peak load during the winter months due to extreme cold weather.
- Based on the planned maintenance, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during the 2025–2026 Winter.
- During extreme winter conditions, SaskPower would utilize available demand-response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions to manage the situation.

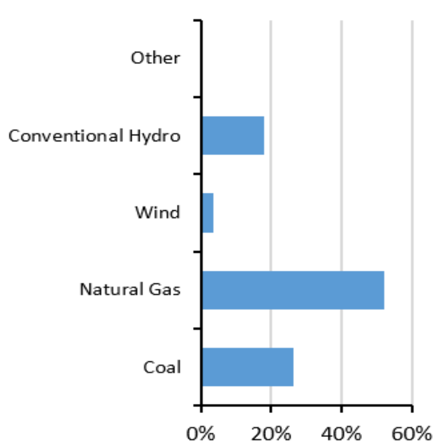
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

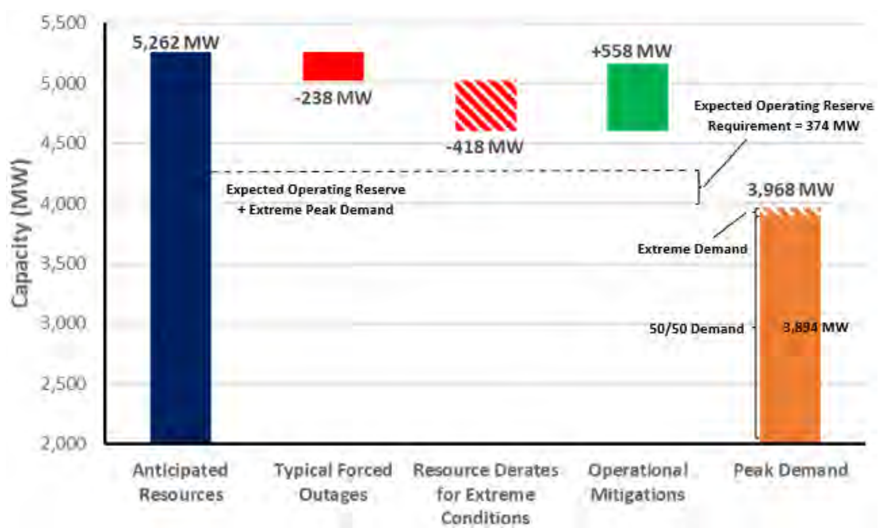
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Based on the historical load variability, SaskPower calculates a probability density function for load to simulate various scenarios that include extreme conditions.

Typical Forced Outages: Estimated using SaskPower forced outage model

Resource Derates for Extreme Conditions: Wind capacity is derated by 96% due to the cut-out of most wind farms below -30°C. Solar generation is expected to be fully unavailable under extreme conditions.

Operational Mitigations: Includes the non-firm import capability (360 MW) and generators in layup status (167 MW) that can be brought online with one to five days' notice; additional demand-side resources are estimated based on other demand response programs and non-firm loads that require 15 minutes to 2 hours of notification

MRO-SPP

SPP'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.

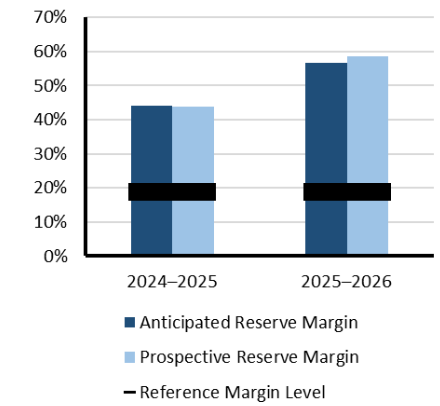
Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season even as SPP continues to set new winter season load records.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2025–2026 Winter season but realizes that interruptions to fuel supply combined with higher penetration of variable energy resources could create unique operation challenges.
- SPP continues to work at enhancing communications and operator preparedness with neighboring regions to address potential electric deliverability issues associated with extreme weather events.
- To minimize conservative operations, EEAs, and mid-range forecast error uncertainty response in wind forecasts, SPP implemented several new operational mitigation processes and procedures to deal with high-impact real-time areas of reliability concern.
- SPP has proposed numerous resource adequacy initiatives, including addressing EUE standards, fuel assurance, winter planning reserve margins, outage policies, demand response, and accreditation; all were recently approved by FERC.

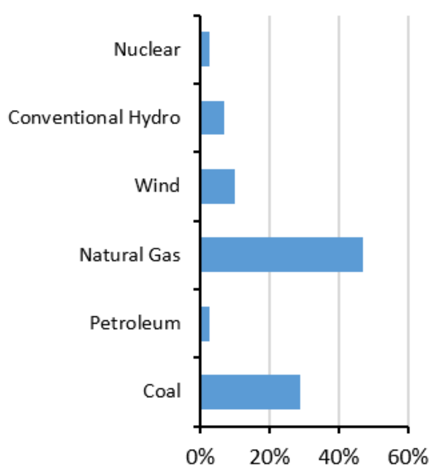
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

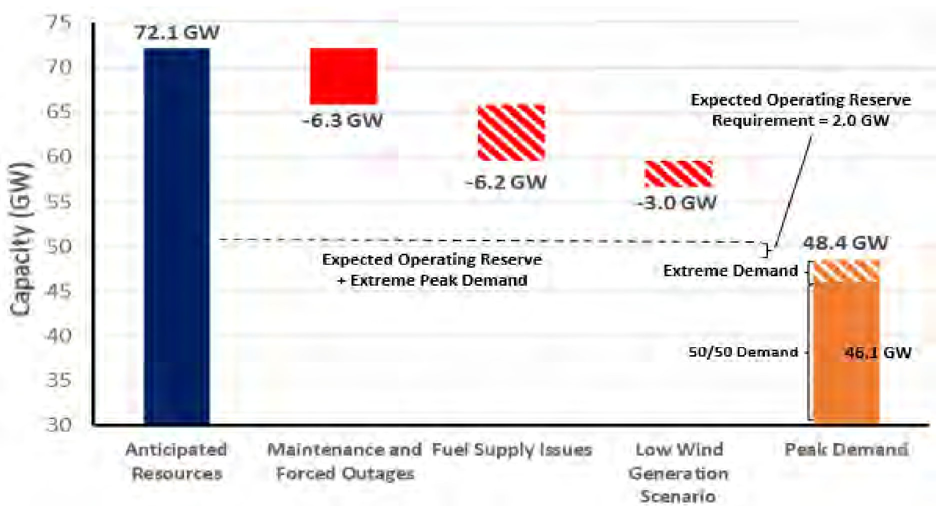
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 using historical data

Maintenance and Forced Outages: A capacity derate of 6.3 GW for maintenance outages, forced outages, and performance in extreme weather based on historical data

Fuel Supply Issues: BA derate of 6.2 GW based on MW capacity of gas-fired generators experiencing fuel supply issues in winter storm Elliott.

Low Wind Generation Scenario: 3 GW of wind potentially off-line when temperatures fall below their cold weather performance packages

NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the balancing authority for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the balancing authority for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

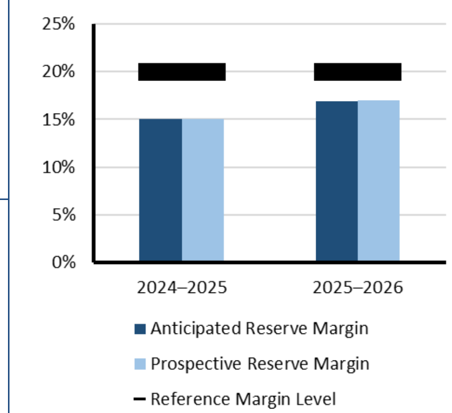
Highlights

- The Maritimes has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind, dual-fuel oil/gas, tie benefits, and biomass with no one type making up more than about 27% of the total capacity in the area.
- The Maritimes has long-term energy contracts in place for its winter supply and can purchase additional energy in the day-ahead and in real time as required.
- As part of the winter planning and preparation process, dual-fueled units will have sufficient supplies of heavy fuel oil stored on site to enable sustained operation in the event of natural gas supply interruptions.

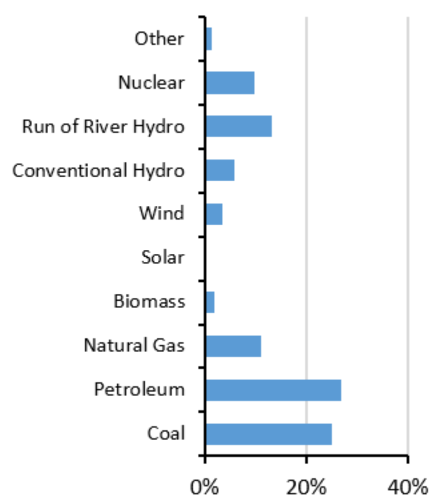
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates some risk of unserved energy and LOLH under high demand or low resource scenarios.

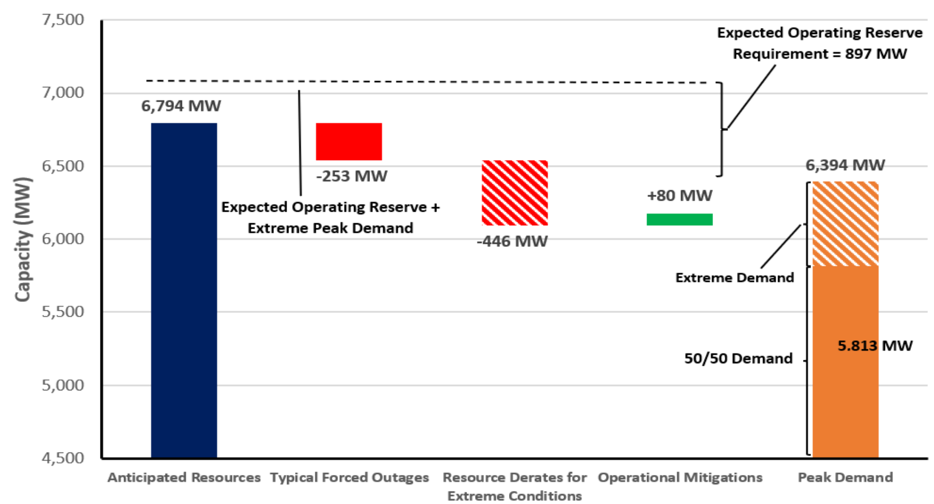
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Scenario peak load with adjustment calculated by adding a 10% margin of error to the peak internal demand forecast taken from the *Long-Term Reliability Assessment* (LTRA) for the 2025–2026 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2024)

Typical Forced Outages: Based on historical operating experience

Resource Derates for Extreme Conditions: Based on ambient temperature thermal derates, wind derated to zero, as well as natural gas capacity derated by 50% due to supply issues

Operational Mitigations: Based on emergency operations and planning procedures in place including fuel switching

NPCC-New England

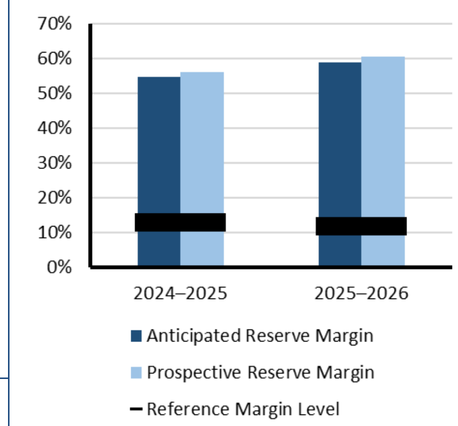
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New 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 expects to meet its regional resource adequacy requirements this 2025–2026 Winter operating period without calling upon operating procedures to maintain a balance between electricity supply and demand.
- A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquefied natural gas (LNG)).
- ISO-NE expects to have sufficient capacity resources to meet the 2025–2026 50/50 and 90/10 winter peak demand forecast of 19,616 MW and 21,125 MW, respectively, for the weeks beginning January 10, January 17, and January 24.
- ISO-NE has recently developed the Regional Energy Shortfall Threshold (REST) as an effort to quantify the tolerable risk of energy shortfall during extreme events. Within the 0.25% highest-risk scenarios, the REST thresholds are 3.0% normalized EUE over 72-hour periods and 18.0 hours over 21-day periods.
    - o ISO-NE does not anticipate exceeding the REST criteria for Winter 2025–2026.

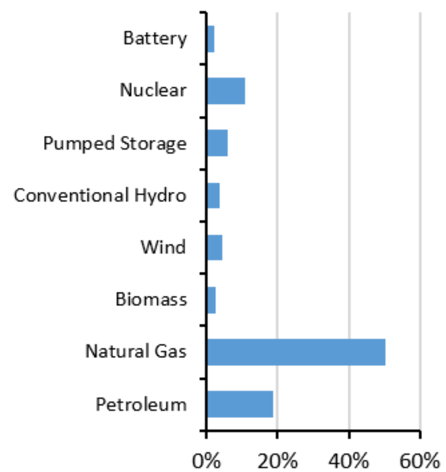
On-Peak Reserve Margin



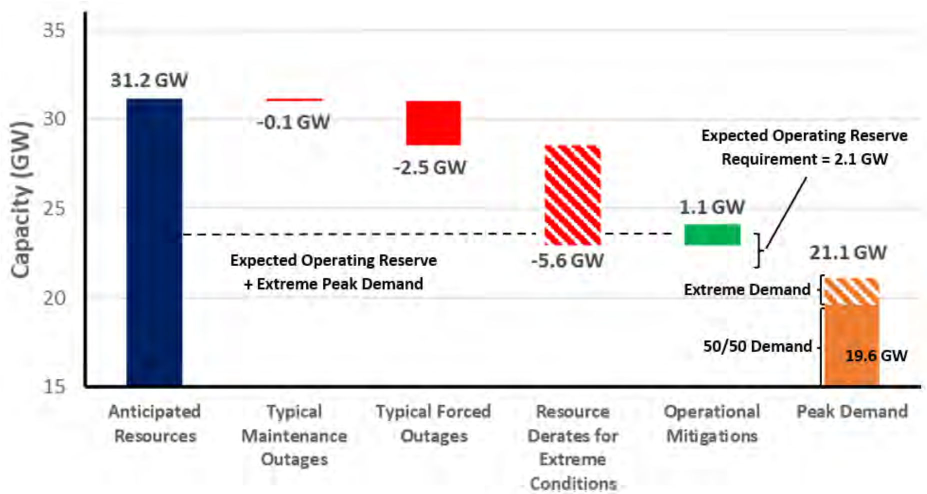
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with high generator outages could result in the need for operating mitigations (i.e., demand response and transfers). Prolonged extreme cold weather events that result in depletion of stored fuels can lead to resource shortfalls.

On-Peak Resource Mix



2025–2026 Winter 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 capturing the region's coldest day in the last 30 years using current and future load models

Typical Maintenance Outages: Based on historical weekly averages

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

Resource Derates for Extreme Conditions: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages

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 WRA, the established RML 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%.

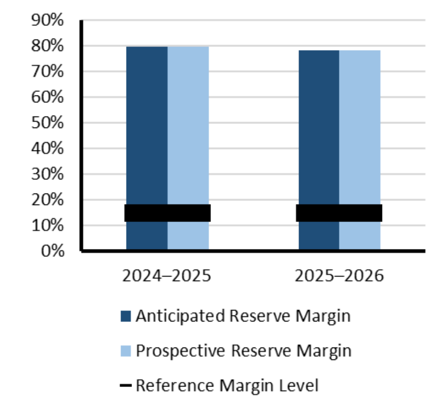
Highlights

- New York is presently a summer-peaking area, and no emerging reliability issues are anticipated during the 2025–26 Winter assessment period.
- Expected resources meet operating reserve requirements under the assessed demand and resource scenarios. A scenario involving an extended cold snap that causes above-normal demand and diminished natural gas supplies would result in low but sufficient reserves.
- The preliminary results of the NPPCC winter probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOL,H or EUE risks were indicated over the December–February winter period for all the scenarios modeled.

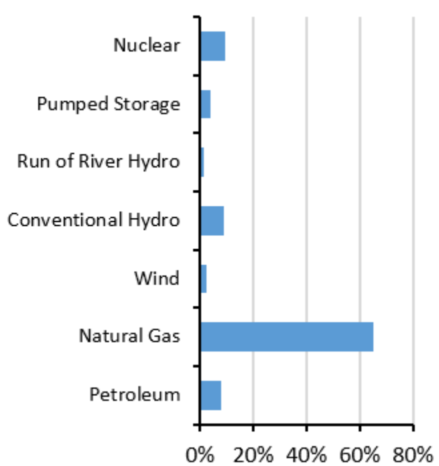
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed demand and resource scenarios.

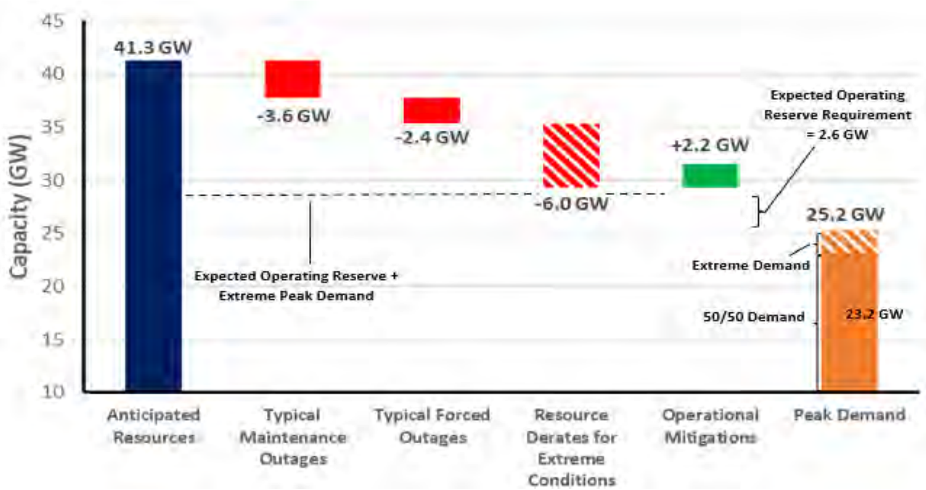
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 Maintenance Outages: Based on planned scheduled maintenance

Typical Forced Outages: Based on 5–year averages from GADS data.

Resource Derates for Extreme Conditions: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather. Based on a 2025 analysis, approximately 6,307 MW of gas generation with non-firm fuel supplies could be unavailable.

Operational Mitigations: Based on NYISO operating procedures

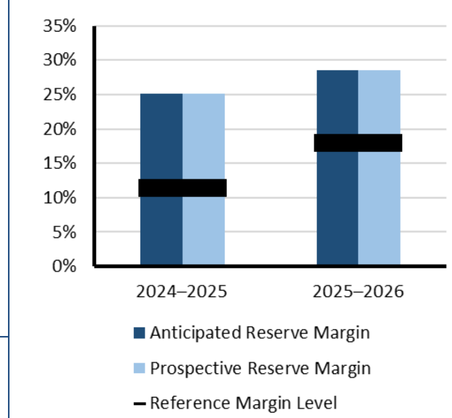
NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of almost 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

Highlights

- As Ontario is a summer-peaking province, there is typically a lower risk of reliability issues during the winter than the summer. However, Ontario regularly experiences extreme cold weather in the winter.
- NPCC-Ontario is well prepared for Winter 2025–2026, and IESO expects that the electric system will remain reliable with reserve margins well above required levels.
- Operators and forecasters in Ontario work closely with neighboring jurisdictions to manage extreme weather events.
- Natural-gas-fired generators in Ontario are supplied by pipelines with access to the Enbridge Gas Dawn Hub and its associated storage facilities, which significantly reduces natural gas deliverability and reliability concerns by connecting those systems to several major gas transportation corridors, enabling access to multiple supply basins.

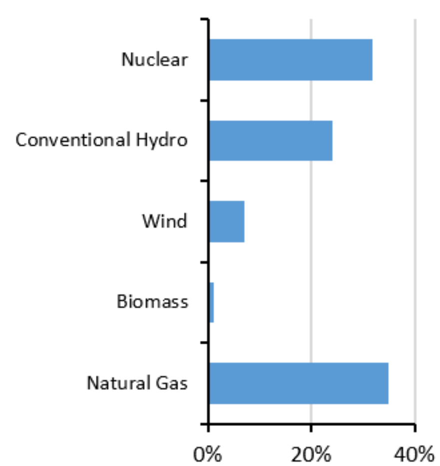
On-Peak Reserve Margin



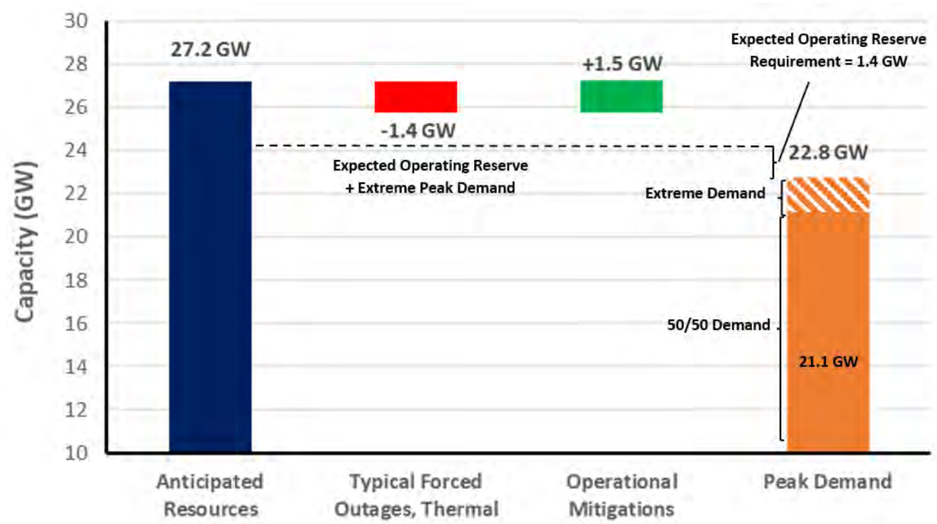
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter 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 from 31 years of winter demand history

Typical Forced Outages, Thermal: Based on analysis of a rolling five-year history of actual forced outage data.

Operational Mitigations: Imports anticipated from **neighbors** during emergencies

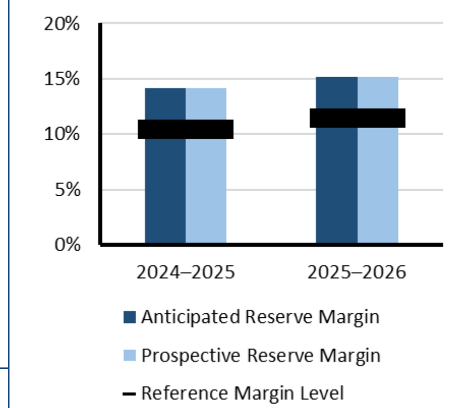
NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominately hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

Highlights

- NPCC-Québec projects adequate capacity margins above its reference reserve requirements and that system resource adequacy will be maintained for the province for the 2025–26 Winter assessment period.
- No hydropower performance issues are expected during extreme cold because of design criteria for cold weather.
- No fuel supply or transportation issues are anticipated for the upcoming winter season.
- While a slight decrease in net firm transfers has occurred since last winter (-89 MW), significant increases in demand-side management programs (+450 MW year-over-year) have been realized over the same period and are expected to compensate for this winter's modest expected load growth.

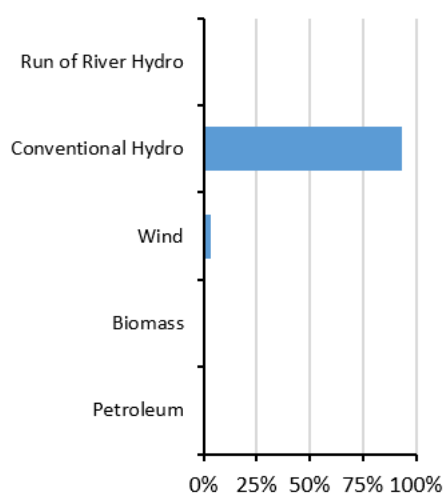
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Demand forecasts include demand-side resources. The demand side resources are the same for the 50/50 and extreme demand scenarios. The extreme load forecast is determined at two standard deviations higher than the mean, which has a 6.06% probability of occurrence.

Extreme Derates: Maintenance outages and other deratings are already included in existing-certain capacity calculation. Wind capacity is 64% derated

Typical Forced Outages: Unplanned outages are 1,500 MW.

Operational Mitigations: Operational mitigations include imports from neighboring areas and reduction of reserves

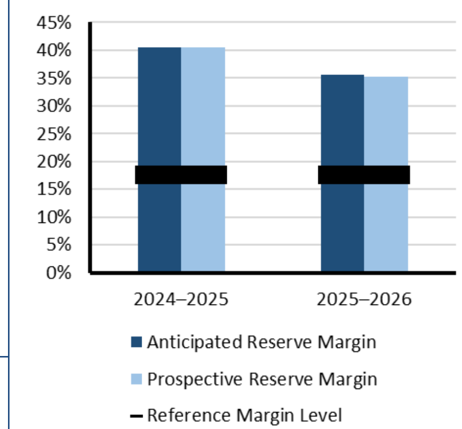
PJM

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's footprint covers approximately 369,054 square miles and with an approximate population of 67 million people. PJM is the area's BA, Transmission and Resource Planner, interchange authority, TOP, transmission service provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Highlights

- Due to the low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with highest loss-of-load risk remains the hour with highest forecasted demand.
- PJM is expecting little capacity adequacy risk during Winter 2025–2026 and expects around 35% installed reserves, which is above the target IRM of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- Last winter, PJM hit a new all-time winter peak, but generator preparations anticipating congestion and tight capacity projections led to sufficient reserves throughout the demand event and PJM's transmission system performed well.
- The decrease in reserves from Winter 2024–2025 is due to load increases and retirement of generation without like (non-solar dispatchable) replacement generation.

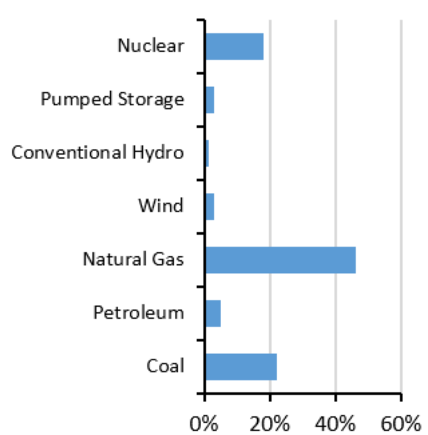
On-Peak Reserve Margin



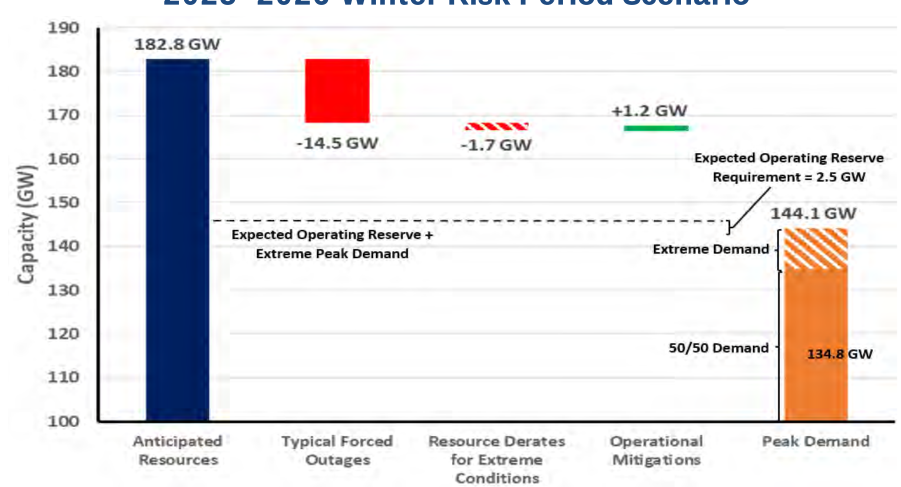
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter 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: Based on historical data and trending

Resource Derates for Extreme Conditions: Reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: accounts for an estimated value 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 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.

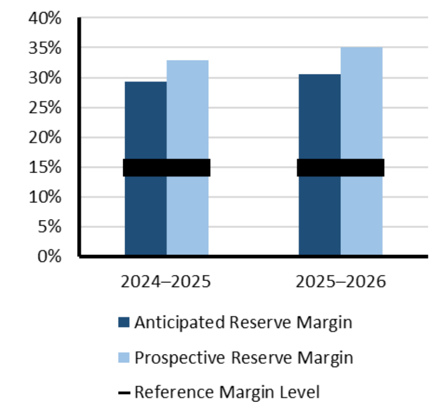
Highlights

- SERC-Central is transitioning from a summer-peaking area to a dual-peaking system.
- For the 2025–2026 Winter, SERC-Central projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Most entities across SERC-Central report that fuel security is strong since it is supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal inventories are projected to remain within operational ranges necessary to meet winter demand.
- Following lessons from Winter Storm Elliott, one SERC-Central entity raised its winter Planning Reserve Margin target to 26% and updated preparedness programs with improved heat trace capabilities.

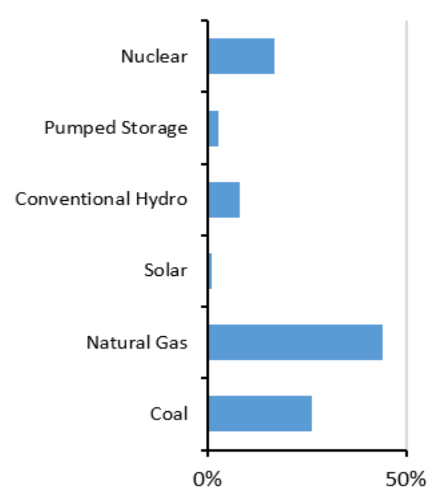
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand. A severe cold weather event that extends to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

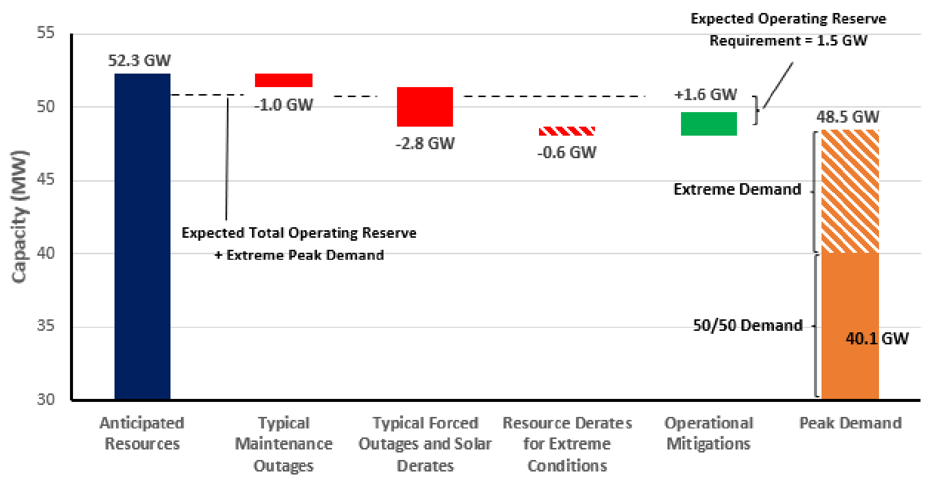
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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

Typical Maintenance Outages: Data collected through a survey of members for expected outages during December through February

Typical Forced Outages and Solar Derate: Includes any weighted average forced-outage rates on-peak that are not factored into the anticipated resources calculation . Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions

Operational Mitigations: A total of over 1.6 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 Regional Entities 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 United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

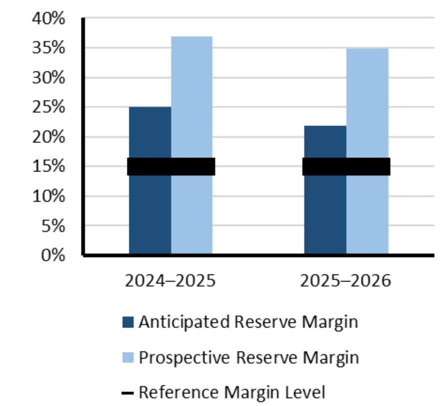
Highlights

- SERC-East is transitioning from a summer-peaking area to potentially peaking during both summer and winter. This shift is attributed to the continued addition of solar PV generation, which reduces summer peak demand, and a trend toward electrification of heating, which drives up winter peak demand.
- For the 2025–2026 Winter, the SERC-East region projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Fuel supplies and transportation remain stable, and entities anticipate maintaining adequate coal and oil inventories with no reported changes to fuel procurement or operator plans for the upcoming winter.
- Probabilistic Base Case Results (Median Weather): EUE is 61.95 MWh and LOLH is 0.06 hours/year. EUE values are likely due to higher winter peaks and/or lower supply of capacity that can meet early winter morning demand.
- Mitigation measures for extreme conditions include voltage reduction (25–50 MW) and load-shedding programs that cover up to 30% of system load.

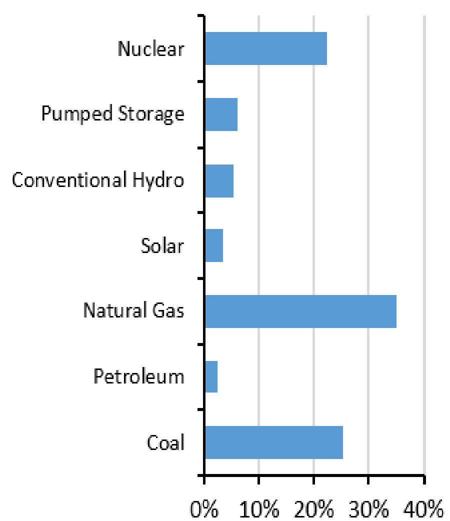
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

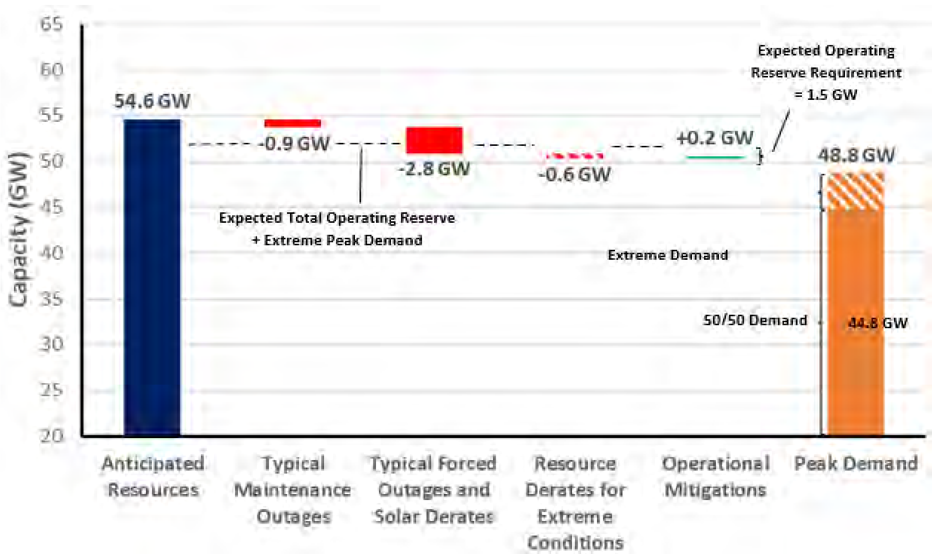
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages (excluding 2022–2025)

Operational Mitigations: A total of 0.2 GW based on operational/emergency procedures

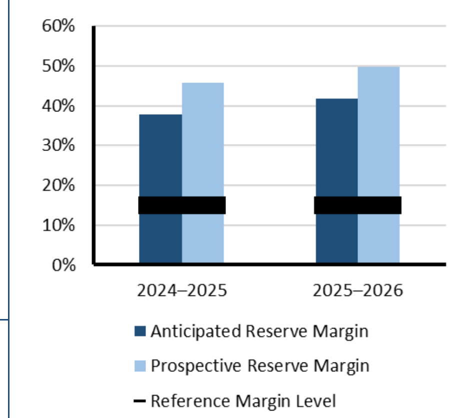
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six Regional Entities across North America that is 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 United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

Highlights

- SERC-Florida Peninsula is a summer-peaking assessment area.
- Florida Peninsula entities have not identified any emerging reliability issues for the upcoming 2025–26 Winter season with an ARM projected at 39%, well above the RML, while the 2024 NERC ProbA base-case results project a sufficient level of resources to serve the expected load under median weather and typical system operating conditions (EUE is 1.09 MWh and LOLH is 0.00 hours/year).
- Many entities report strong fuel security, supported by firm natural gas contracts, storage resources, reliable pipeline capacity, and actively managed coal and oil inventories, which are projected to remain within operational ranges to meet winter demand.
- Florida Peninsula entities do not assume non-firm external assistance from neighboring areas during extreme conditions.

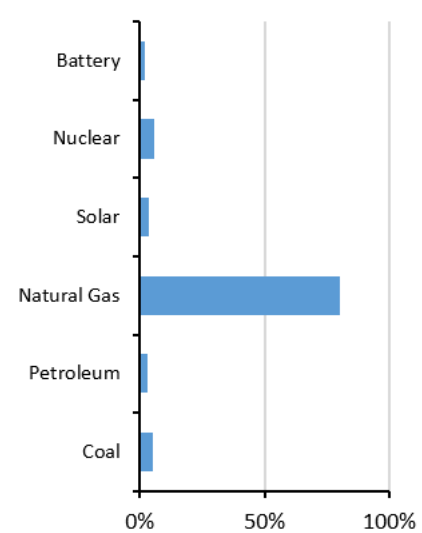
On-Peak Reserve Margin



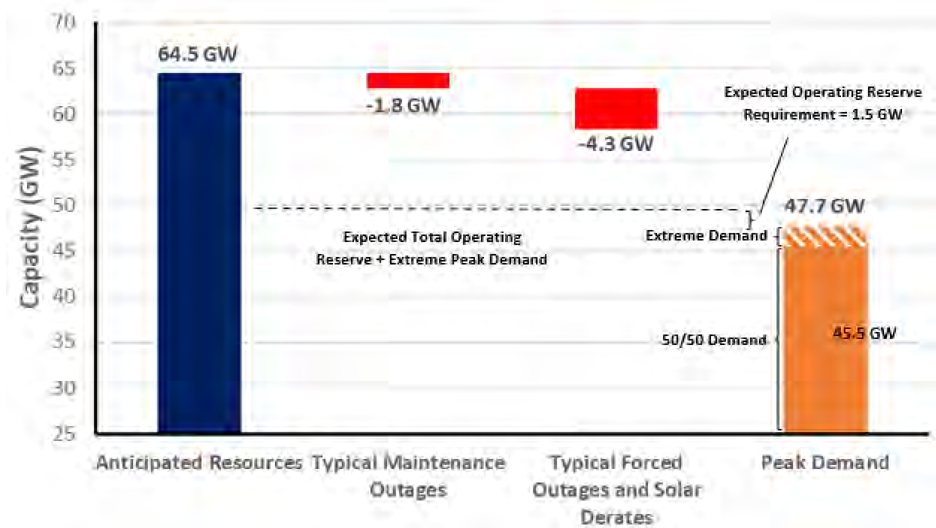
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter 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

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood 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 Regional Entities across North America that is 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 United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

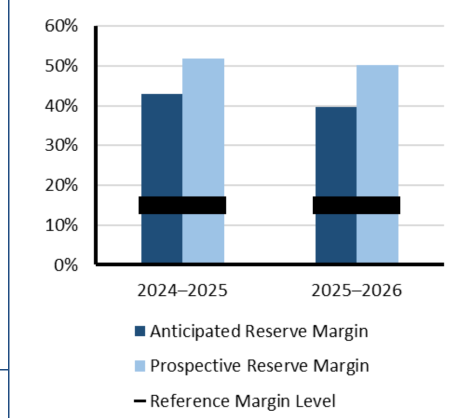
Highlights

- SERC-Southeast is trending towards becoming slightly winter-peaking.
- For the 2025–2026 Winter, SERC-Southeast entities report no emerging reliability concerns and expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories to serve the expected load under typical system operating conditions. The 2024 NERC ProbA base-case results in EUE and LOLH are both 0.00.
- While most SERC-Southeast BAs expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories, one BA highlights potential risks related to natural gas transportation capacity, citing high pipeline utilization, competition for delivered gas, and ratable flow requirements. Mitigation strategies include securing third-party gas supply, adding dual-fuel capability, and implementing coal inventory management.
- Entities have made refinements such as replacing specific 230 kV circuit breakers and increasing monitoring frequencies for critical plant systems after January 2025 winter events.

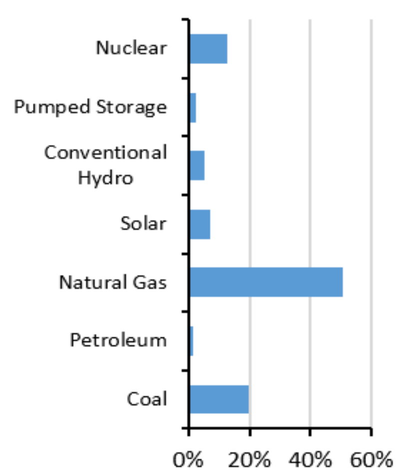
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

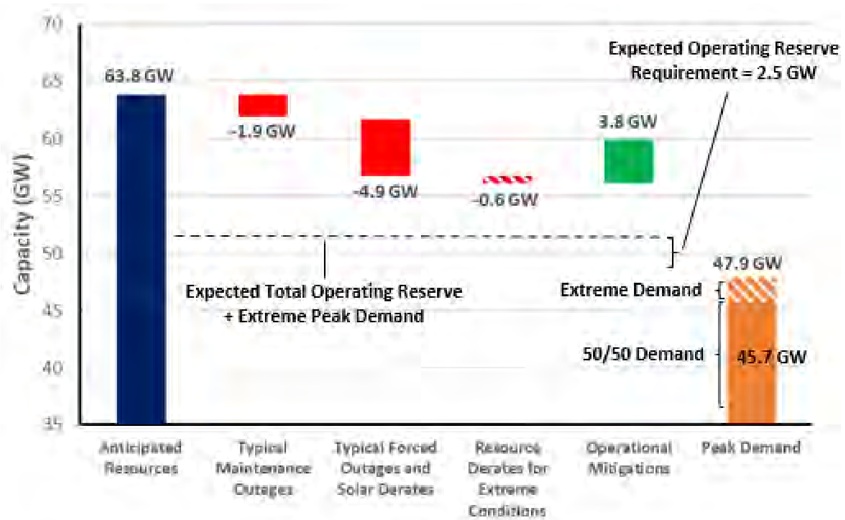
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures

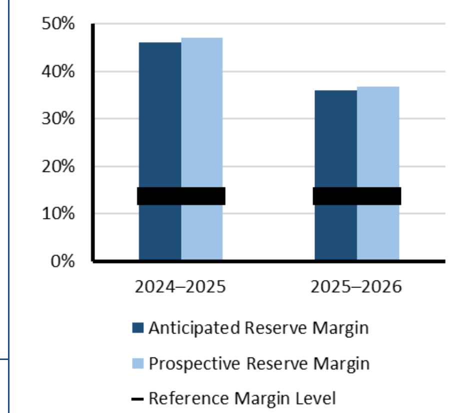
Texas RE-ERCOT

ERCOT is the 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 covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 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 power grid.

Highlights

- Given expected system conditions, an ARM of 36% and RML of 13.75%, ERCOT expects to have sufficient operating reserves for the peak hour ending 8:00 a.m.
- ERCOT does not expect any significant fuel supply issues for the winter.
- ERCOT has conducted 2,028 generation resource and transmission service provider (TSP) winter weatherization inspections since Winter 2021–2022.
- Winter peak demands typically occur before sunrise and after sunset when solar generation is not available. Significant battery storage mitigates these risks.
- ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
- Increased load growth in west Texas combined with "no solar" and low wind conditions can cause transmission lines into this area to become heavily loaded. ERCOT has introduced improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low irradiance.

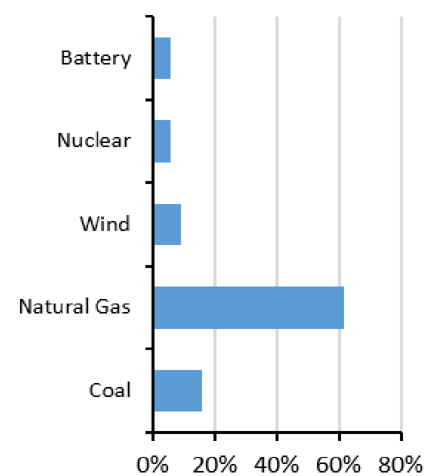
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Presumes weather conditions comparable to Winter Storm Uri. The adjustment is calculated as the difference between the 100th percentile and 50th percentile values from ERCOT's Probabilistic Reserve Risk Model (PRRM) simulated load outcome distribution for hour ending 8:00 a.m.

Typical Maintenance Outages: Based on historical winter data and consideration of ERCOT's allowed maximum system daily planned outage capacity

Typical Forced Outages: Based on a probability distribution created using historical ERCOT Outage Scheduler data for the last three Januarys.

Resource Derates for Extreme Conditions: Weather-related thermal and wind outages based on Winter Storm Uri levels, adjusted for reductions due to weatherization standards. Also includes high non-weather-related outages.

Operational Mitigations: Additional potential capacity from switchable generation and imports

WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas: Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

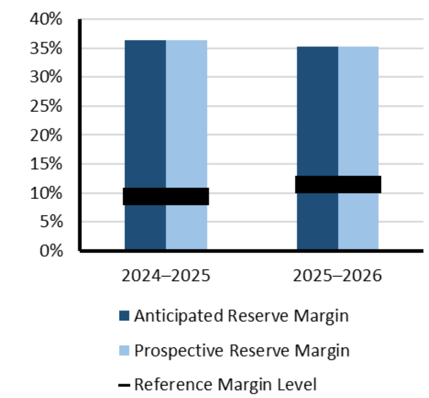
Highlights

- At an extreme winter peak of 12,982 MW, with extreme forced outages at 530 MW and derates for extreme conditions bringing wind energy availability down by 1,800 MW and hydroelectricity by 88 MW, the required reserves are 759 MW and are sufficiently met, even with low availability.
- Demand is expected to increase 1.1% from last winter with the existing-certain installed capacity having increased 23%.
- Solar availability is down because 1,000 MW of PV moved from originally expecting to come on-line in 2024 as Tier 1 resources to Tier 2s mostly anticipated to come on-line in 2025, but with less certainty.

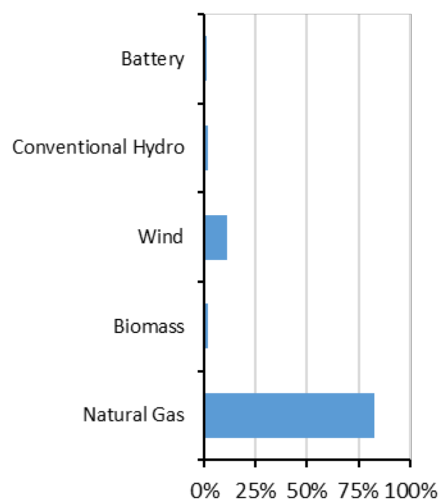
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

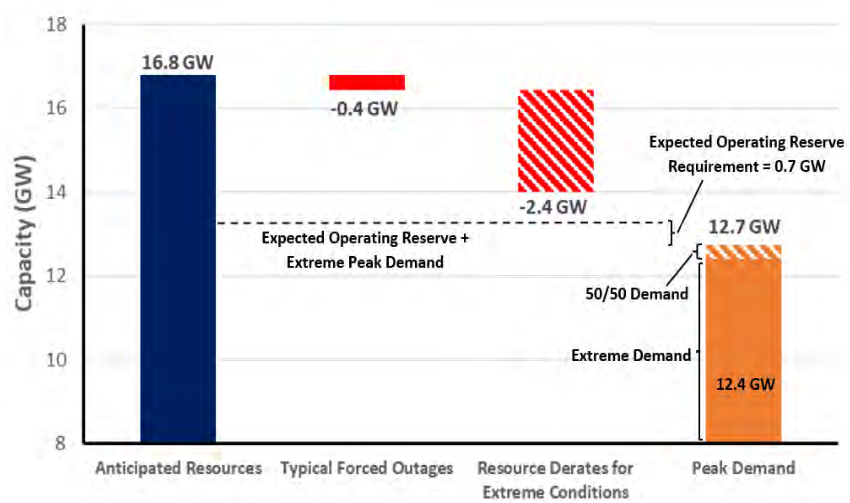
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS data

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

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 BA 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 2025-26 WRA 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 2024–25 WRA.*

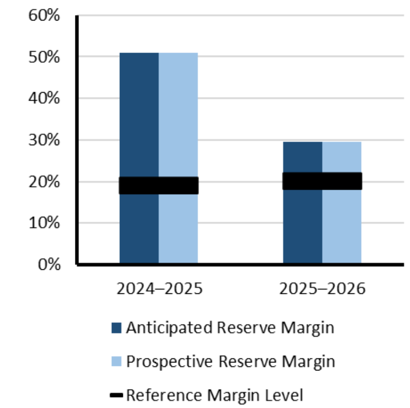
Highlights

- At an extreme winter peak of 11.1 GW under an extreme combination of derates and outages, the region could be short 1.0 GW before imports and is expected to need to rely on transfers.
- Net internal demand is expected to increase 1% since last year, with total internal demand up 1.8% being offset by a doubling of controllable and dispatchable demand response.
- Tier 1 resources have declined and do not appear to be offset by increases in existing-certain generation resource capacity. Nameplate wind has increased by almost 18% and solar by almost 30%. Hydro is also up over 7% in total installed capacity.
- Reliance on imports is expected to be required to maintain resource adequacy during extreme peak demand and extreme derate conditions.

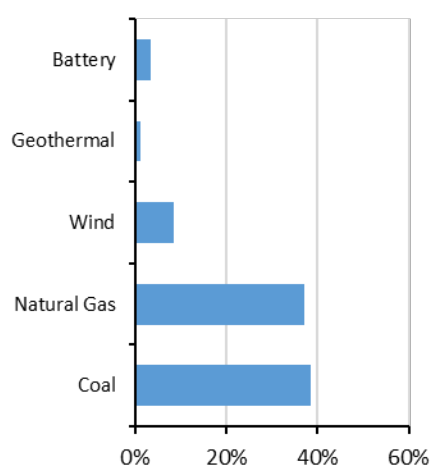
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

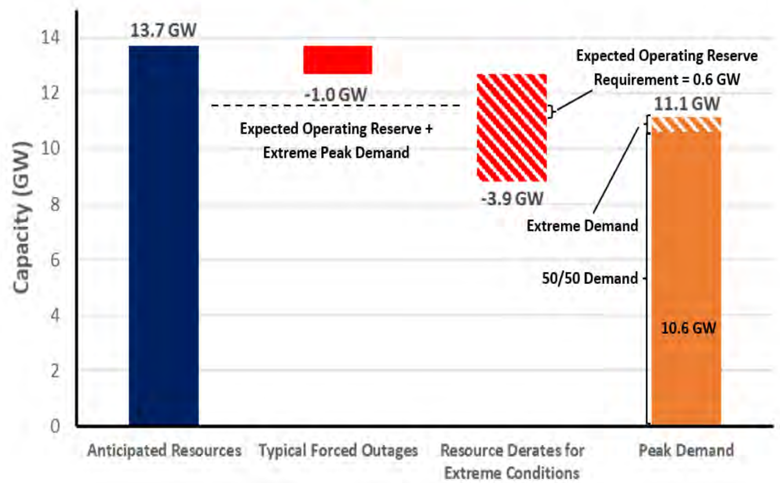
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Extreme Derates: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas: the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during winter.

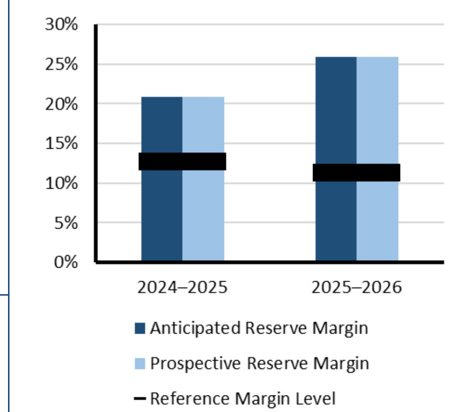
Highlights

- Peak demand is expected to remain about the same as last winter.
- There are about 200 MW more (47%) planned Tier 1 resources for this winter than last.
- Solar nameplate capacity has increased from 2 MW to 17 MW since last winter and hydroelectric nameplate capacity is up more than 5%, or 1,366 MW.

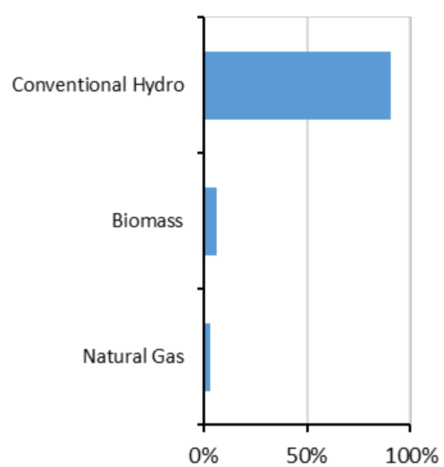
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme demand scenarios.

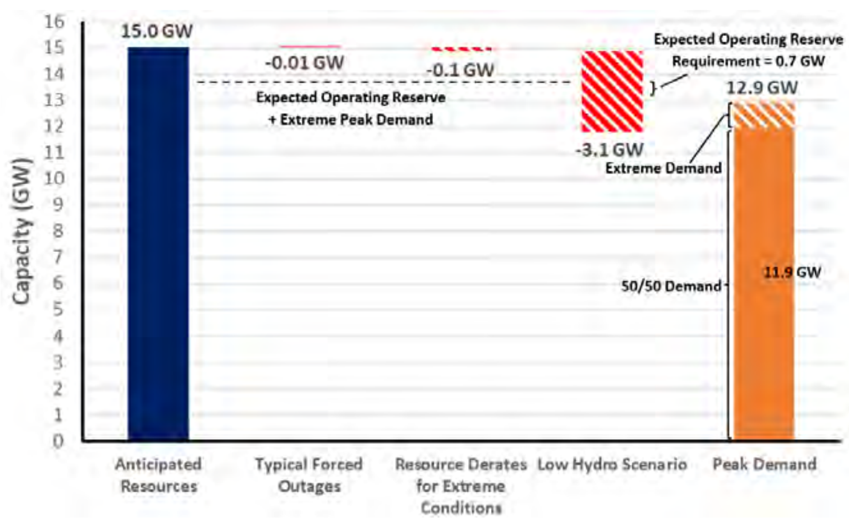
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Low Hydro Scenario: Estimated derate for lower hydro output

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, the Los Angeles Department of Water and Power, the 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 2025–26 WRA 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 2024–25 WRA.*

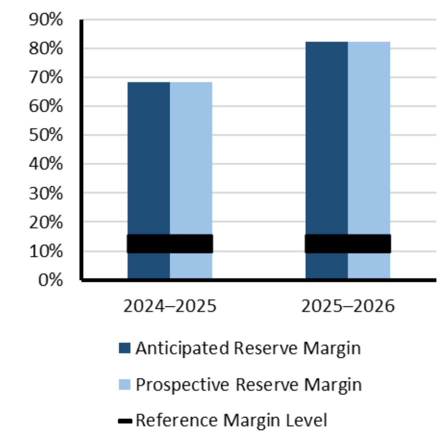
Highlights

- Operating reserve margins are met before imports in all winter resource availability scenarios.
- On-peak demand is expected to remain about the same as last winter. Demand-side management is down about 10%.
- Existing-certain capacity is up almost 5%, while planned Tier 1 resources are up more than 2 GW. The total wind nameplate capacity is up almost 27% and solar almost 13%. Hydro is down 4%.
- No reliance on imports is expected to be required to maintain resource adequacy for Winter 2025–2026.

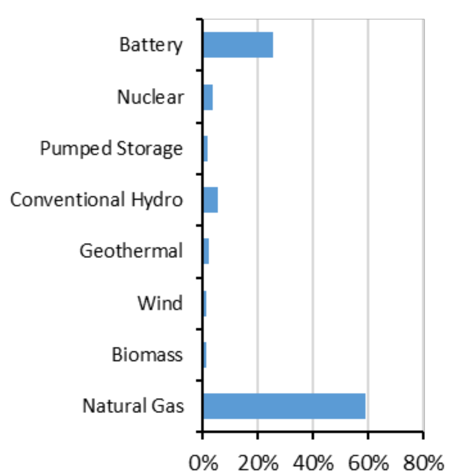
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

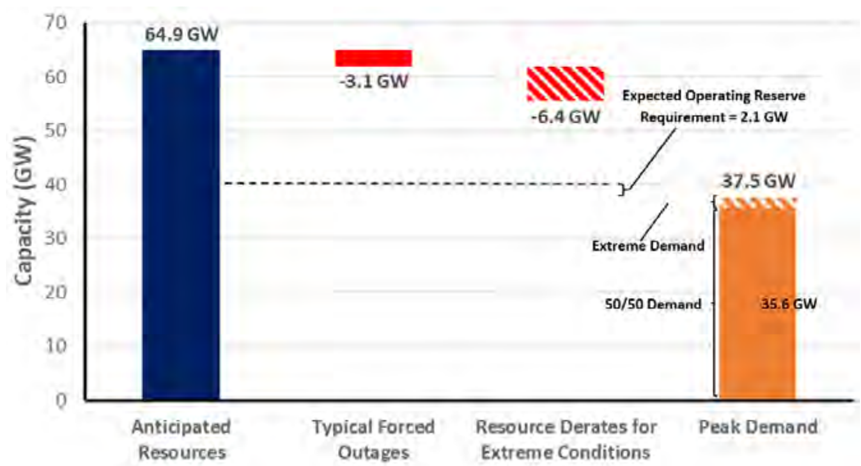
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

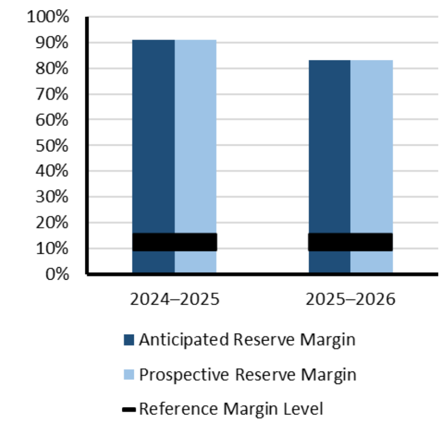
WECC-Mexico

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 2025–26 WRA 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 2024–25 WRA.*

Highlights

- As a summer-peaking region, operating reserve margins are met before imports in all scenarios.
- Planned Tier 1 resources are down 100% to zero as expected resources have either been brought on-line to move into existing or, in the case of some natural gas, have been delayed until 2026 and moved into Tier 2.
- The existing-certain on peak reserve margin is down by 5.2%, and the anticipated and prospective reserve margins are down by 7.8%; however, since Mexico is heavily summer-peaking, the 83% reserve margin still exceeds the RML of 12.5%, which remains unchanged.

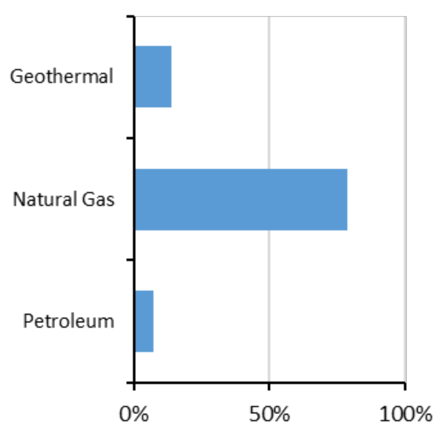
On-Peak Reserve Margin



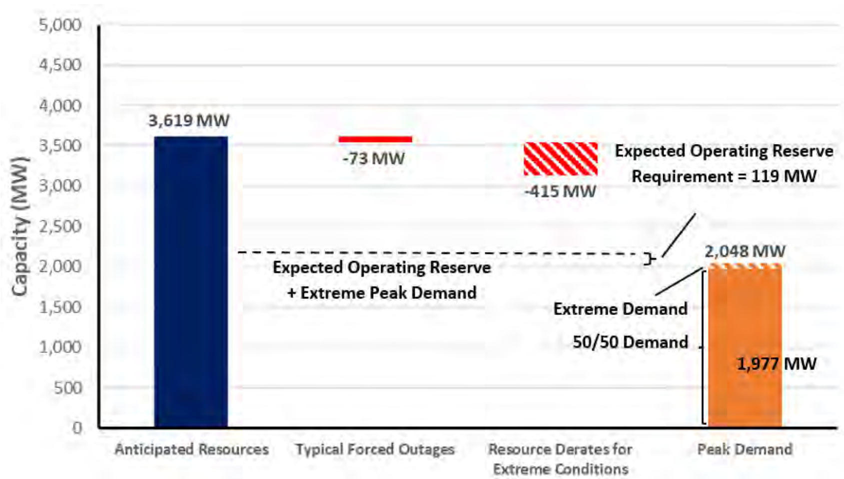
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

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 2025–26 WRA 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 2024–25 WRA.*

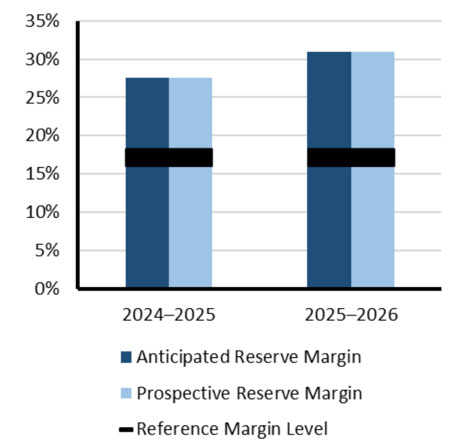
Highlights

- The Northwest has historically been a mixed season-peaking region.
- Operating reserve margins are expected to be met after imports in all winter scenarios.
- Total and net internal demand are up 9.3% with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing.
- Large coal unit retirements and conventional hydro unit retirements are attributable to the reduction in existing certain capacity of 10.5%; however, planned Tier 1 resources have soared over 580%, from 463 MW to over 3 GW.
- Nameplate wind capacity is up over 3 GW (26%) and solar nameplate capacity is up nearly 2,690 MW (134%), which has also increased the solar availability on the peak hour.
- An increase in firm imports is seen in the model, 6.1 GW, absorbing the reduction in existing certain capacity of 4 GW.

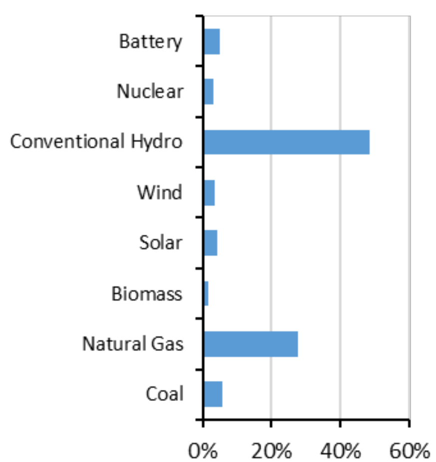
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

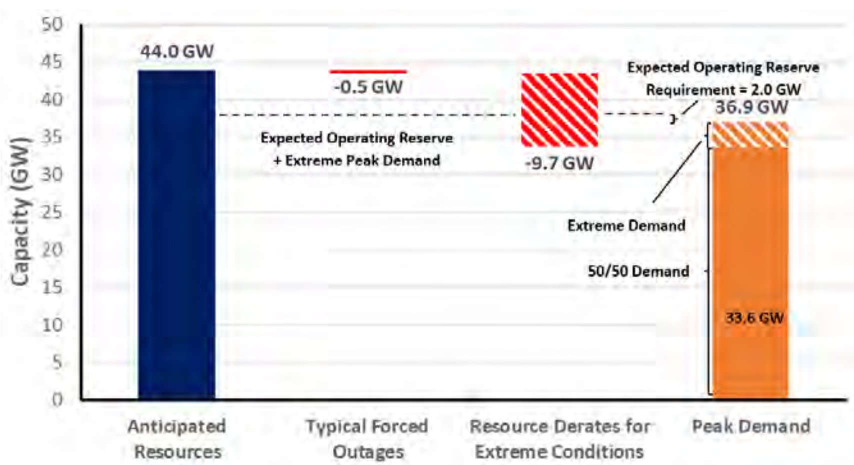
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period. This value includes 6.8 GW of hydro derates.

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 2025–26 WRA 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 2024–25 WRA.*

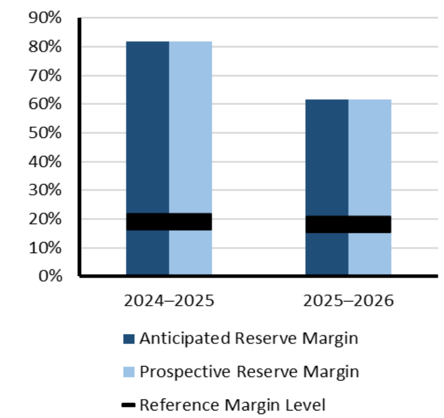
Highlights

- In Rocky Mountain, operating reserve margins are expected to be met before imports in all winter scenarios.
- Total and net internal demand are up almost 1%. The primary drivers are data centers and commercial and industrial customer growth.
- Planned Tier 1 resources are up over 84%, from almost 200 MW to over 365 MW. Solar nameplate capacity is up 27%; however, on-peak solar energy availability is down 100% due to the shift to after sunset. Expected hydro on peak energy availability is also down by around a quarter on the peak hour. Existing-Certain, Anticipated, and Prospective Reserve Margins are all down by over 20% on the peak hour; however, the region still maintains resource adequacy with margins hovering around 60% compared to the RML of 18%.
- No reliance on imports is expected to be required to maintain resource adequacy under combined extreme peak and extreme derated conditions.

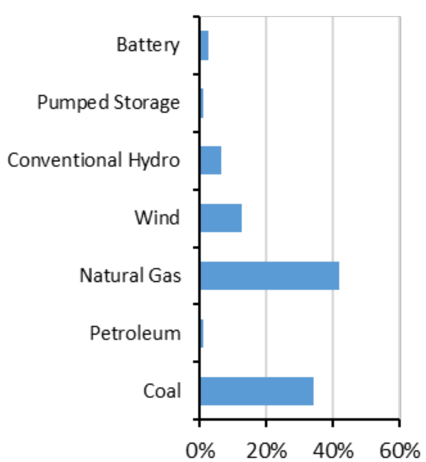
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

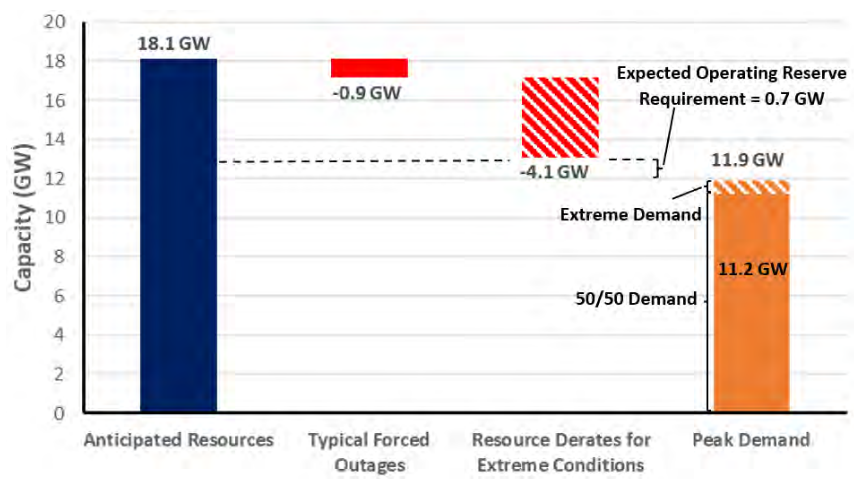
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

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 2025–26 WRA 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 2024–25 WRA.*

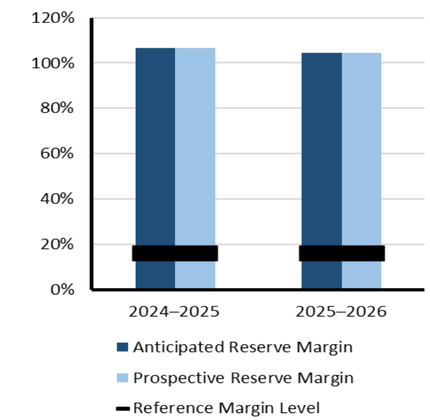
Highlights

- The Southwest is anticipated to be resource adequate under all winter expected and extreme energy availability and demand scenarios before imports.
- Total internal demand is expected to be up 1.5% and net internal demand up 2.3% since last winter. The primary drivers for load growth are data centers and industrial and residential electrification. Controllable and dispatchable demand response is down nearly half, by 163 MW.
- Planned Tier 1 resources are down over 19% as some have moved into existing certain, which is up almost 3%, over 1 GW, and other projects have experienced delays.
- Wind nameplate is up 12%, 470 MW, correlating to on-peak energy availability from wind increasing almost 11%, by 114 MW, while solar nameplate is up 27% or over 2.5 GW.

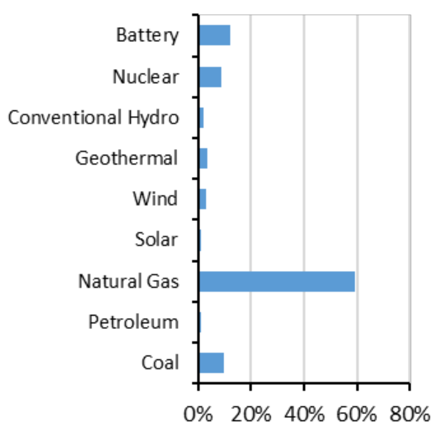
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

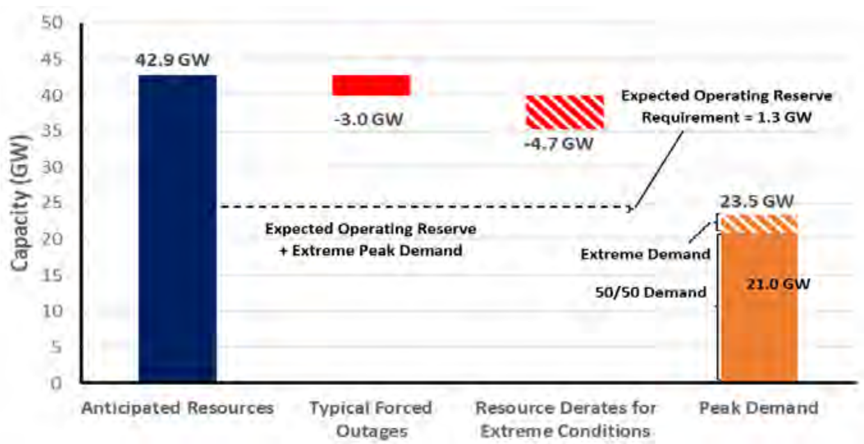
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

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[11] or total internal demand for the summer and winter of each year.[12]
• Total internal demand projections are based on normal weather (50/50 distribution)[13] and are provided on a coincident[14] 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 variable energy resources (VER) (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.

[11] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[12] The summer season represents June–September and the winter season represents December–February.

[13] 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.

[14] 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 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.[15] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet its RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their RML for the 2025 winter as shown in **Figure 4**.

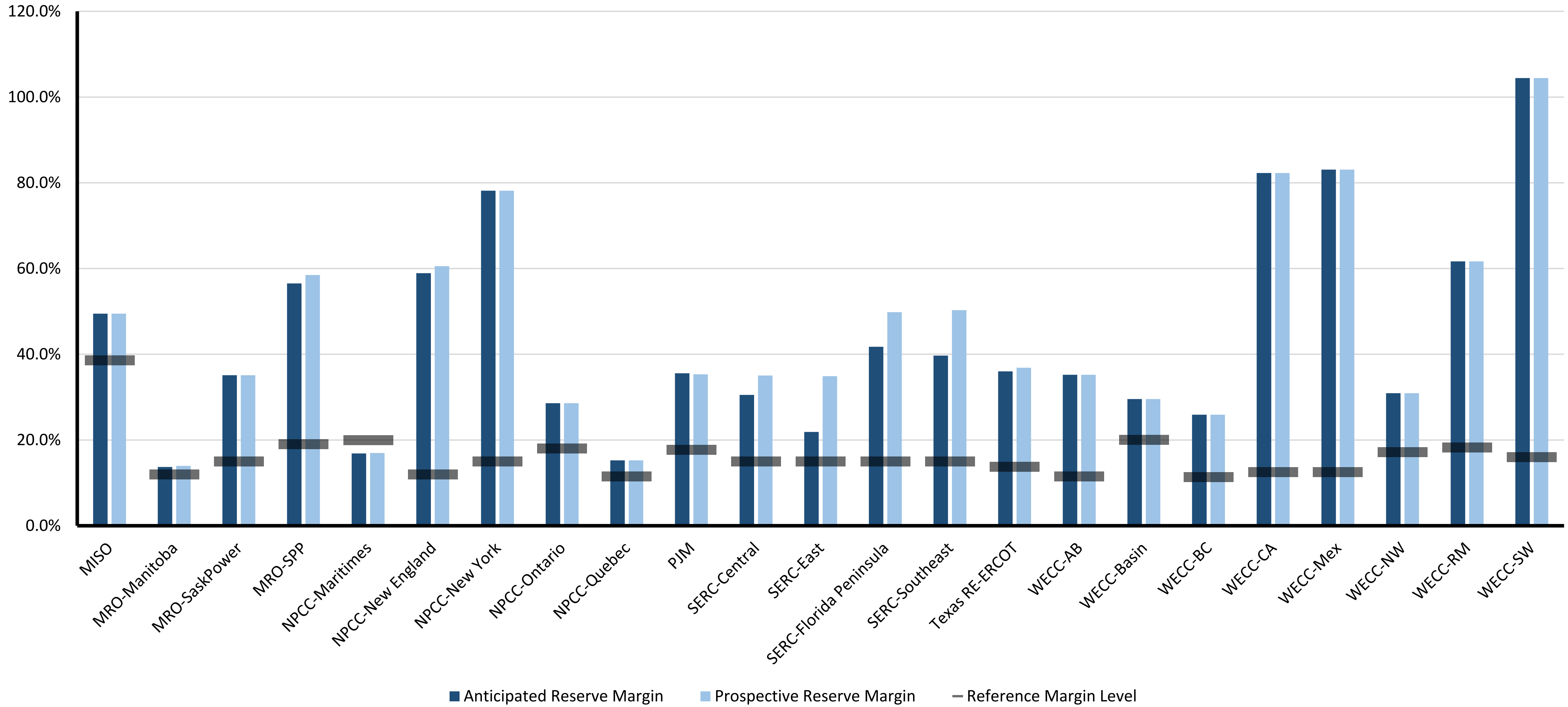


Figure 4: Winter 2025–2026 Anticipated / Prospective Reserve Margins Compared to Reference Margin Level

[15] 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 2024–2025 Winter to the 2025–2026 Winter. All areas except NPCC-Maritimes remain above their RMLs for 2025–2026 Winter. The Canadian winter-peaking systems, which include MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, WECC-Alberta, and WECC-British Columbia, may have reserve margins that are near RMLs but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the **Data Concepts and Assumptions** section.

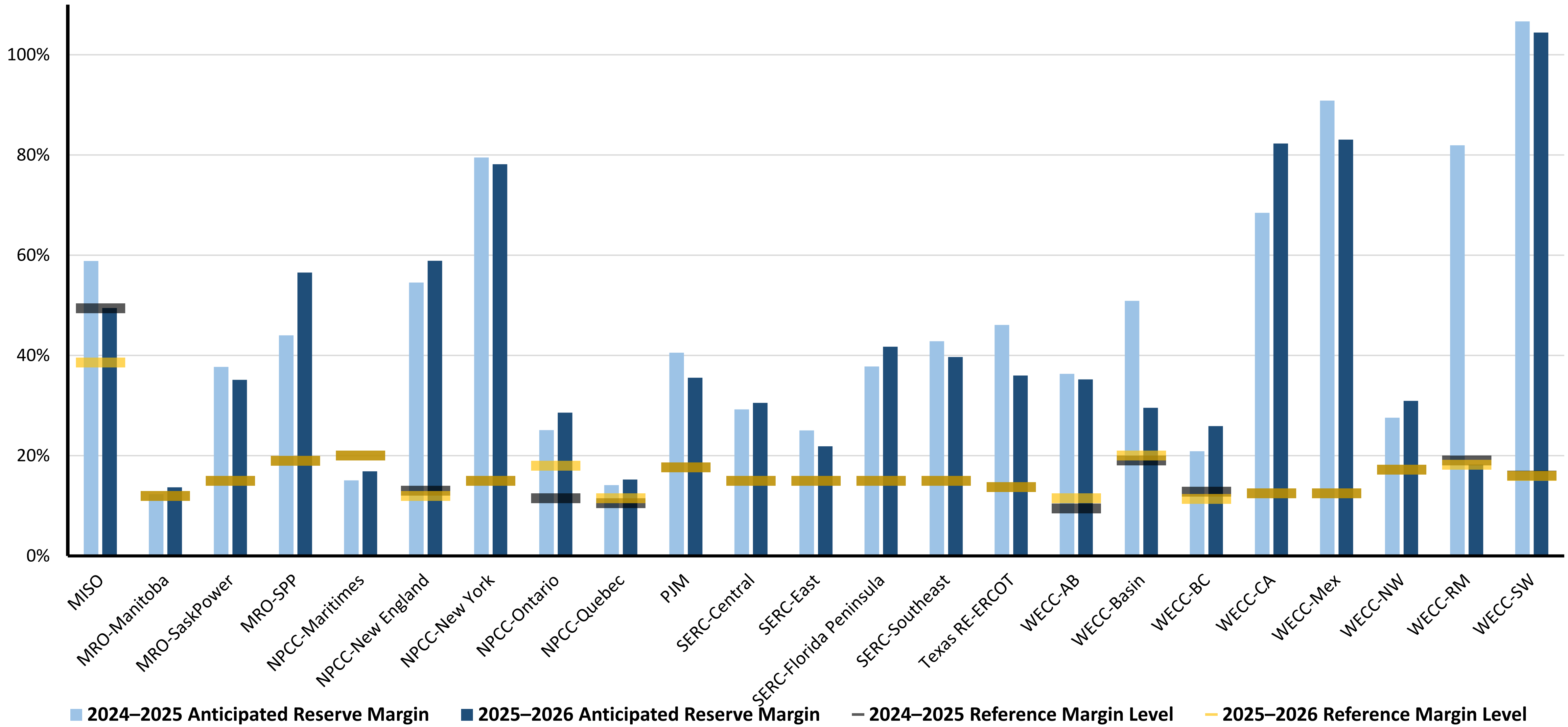


Figure 5: Winter 2024–2025 and Winter 2025–2026 Anticipated Reserve Margins Year-to-Year Change

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table.

MISO			
Demand, Resource, and Reserve Margins	**2024–2025 WRA[16]**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,353	105,249	2.8%
Demand Response: Available	6,219	8,250	32.7%
Net Internal Demand	96,134	96,999	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	150,407	142,880	-5.0%
Tier 1 Planned Capacity	122	0	0.0%
Net Firm Capacity Transfers	2,310	2,113	-8.5%
Anticipated Resources	152,717	144,993	-5.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	152,839	144,993	-5.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	58.9%	49.5%	-9.4
Prospective Reserve Margin	59.0%	49.5%	-9.5
Reference Margin Level	49.4%	38.6%	-10.8

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,788	47,168	3.0%
Demand Response: Available	1,128	1,091	-3.3%
Net Internal Demand	45,926	46,077	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,252	71,074	5.7%
Tier 1 Planned Capacity	0	1087	0.0%
Net Firm Capacity Transfers	-1,116	-32	-97.1%
Anticipated Resources	66,136	72,129	9.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,090	73,029	10.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.0%	56.5%	12.5
Prospective Reserve Margin	43.9%	58.5%	14.6
Reference Margin Level	19.0%	19.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,852	3,944	2.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,802	3,894	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,946	4,972	0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	5,236	5,262	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,236	5,262	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.7%	35.1%	-2.6
Prospective Reserve Margin	37.7%	35.1%	-2.6
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,814	4,903	1.8%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,814	4,903	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,924	5,688	-4.0%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	-527	-113	-78.5%
Anticipated Resources	5,407	5,575	3.1%
Existing-Other Capacity	18	13	-26.8%
Prospective Resources	5,425	5,588	3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.3%	13.7%	1.4
Prospective Reserve Margin	12.7%	14.0%	1.3
Reference Margin Level	12.0%	12.0%	0.0

[16] MISO-provided updated data post 2024-25 WRA publication.

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	6,167	6,061	-1.7%
Demand Response: Available	259	248	-4.4%
Net Internal Demand	5,907	5,813	-1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,647	6,704	0.9%
Tier 1 Planned Capacity	6	88	0.0%
Net Firm Capacity Transfers	145	1	-99.0%
Anticipated Resources	6,798	6,794	-0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,798	6,800	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.1%	16.9%	1.8
Prospective Reserve Margin	15.1%	17.0%	1.9
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,800	24,200	1.7%
Demand Response: Available	802	1,027	28.1%
Net Internal Demand	22,998	23,173	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,522	40,080	-1.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	759	1,203	58.5%
Anticipated Resources	41,281	41,283	0.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,281	41,283	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	79.5%	78.2%	-1.3
Prospective Reserve Margin	79.5%	78.2%	-1.3
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,651	20,056	-2.9%
Demand Response: Available	343	440	28.2%
Net Internal Demand	20,308	19,616	-3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	30,030	29,935	-0.3%
Tier 1 Planned Capacity	194	0	-100.0%
Net Firm Capacity Transfers	1,161	1,235	6.4%
Anticipated Resources	31,385	31,170	-0.7%
Existing-Other Capacity	306	322	5.2%
Prospective Resources	31,691	31,492	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	54.5%	58.9%	4.4
Prospective Reserve Margin	56.1%	60.5%	4.5
Reference Margin Level	13.0%	12.0%	-1.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,898	22,013	0.7%
Demand Response: Available	915	868	-5.2%
Net Internal Demand	20,982	21,146	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,652	27,319	2.5%
Tier 1 Planned Capacity	0	294	#DIV/0!
Net Firm Capacity Transfers	-450	-420	-6.7%
Anticipated Resources	26,202	27,193	3.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	26,202	27,193	3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	28.6%	3.5
Prospective Reserve Margin	25.1%	28.6%	3.5
Reference Margin Level	11.5%	18.0%	6.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,512	40,799	0.8%
Demand Response: Available	4,451	4,902	10.9%
Net Internal Demand	36,061	35,897	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,560	41,698	0.3%
Tier 1 Planned Capacity	73	61	0.0%
Net Firm Capacity Transfers	-479	-390	-18.6%
Anticipated Resources	41,154	41,368	0.5%
Existing-Other Capacity	-479	0	0.0%
Prospective Resources	41,154	41,368	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	15.2%	1.1
Prospective Reserve Margin	14.1%	15.2%	1.1
Reference Margin Level	10.5%	11.5%	1.0

PJM			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	136,328	140,827	3.3%
Demand Response: Available	5,616	5,998	6.8%
Net Internal Demand	130,712	134,829	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,216	178,335	-0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	4,502	4,448	-1.2%
Anticipated Resources	183,718	182,783	-0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	183,718	182,452	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.6%	35.6%	-5.0
Prospective Reserve Margin	40.6%	35.3%	-5.2
Reference Margin Level	17.7%	17.7%	-12.3

SERC-Central			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,895	42,875	0.0%
Demand Response: Available	1,497	2,809	87.6%
Net Internal Demand	41,397	40,067	-3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,578	50,454	-2.2%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	1,922	1,847	-3.9%
Anticipated Resources	53,500	52,301	-2.2%
Existing-Other Capacity	1,498	1,810	20.8%
Prospective Resources	54,998	54,111	-1.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.2%	30.5%	1.3
Prospective Reserve Margin	32.9%	35.1%	2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,005	45,703	1.6%
Demand Response: Available	982	888	-9.6%
Net Internal Demand	44,023	44,815	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,379	54,460	0.1%
Tier 1 Planned Capacity	72	11	-84.3%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	55,045	54,622	-0.8%
Existing-Other Capacity	5,209	5,832	12.0%
Prospective Resources	60,254	60,453	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.0%	21.9%	-3.2
Prospective Reserve Margin	36.9%	34.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,494	48,628	0.3%
Demand Response: Available	2,780	3,127	12.5%
Net Internal Demand	45,714	45,501	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,579	63,502	1.5%
Tier 1 Planned Capacity	15	692	4510.0%
Net Firm Capacity Transfers	400	300	-25.0%
Anticipated Resources	62,994	64,494	2.4%
Existing-Other Capacity	3,673	3,671	0.0%
Prospective Resources	66,667	68,165	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.8%	41.7%	3.9
Prospective Reserve Margin	45.8%	49.8%	4.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,308	47,056	3.9%
Demand Response: Available	1,638	1,365	-16.7%
Net Internal Demand	43,670	45,691	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,805	63,339	0.9%
Tier 1 Planned Capacity	765	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	62,378	63,828	2.3%
Existing-Other Capacity	3,920	4,847	23.7%
Prospective Resources	66,298	68,675	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.8%	39.7%	-3.1
Prospective Reserve Margin	51.8%	50.3%	-1.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	73,193	77,387	5.7%
Demand Response: Available	5,447	9,330	71.3%
Net Internal Demand	67,746	68,057	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	98,712	89,977	-8.8%
Tier 1 Planned Capacity	239	1351	464.9%
Net Firm Capacity Transfers	20	1,235	6075.0%
Anticipated Resources	98,971	92,562	-6.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	99,691	93,137	-6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.1%	36.0%	-10.1
Prospective Reserve Margin	47.2%	36.9%	-10.3
Reference Margin Level	13.75%	13.8%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,280	12,411	1.1%
Demand Response: Available	0	0	0.0%
Net Internal Demand	12,280	12,411	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,535	16,658	23.1%
Tier 1 Planned Capacity	3206	124	-96.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	16,740	16,782	0.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	16,740	16,782	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.3%	35.2%	-1.1
Prospective Reserve Margin	36.3%	35.2%	-1.1
Reference Margin Level	9.5%	11.5%	2.0

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,568	10,758	1.8%
Demand Response: Available	85	170	100.0%
Net Internal Demand	10,483	10,588	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,213	13,183	-0.2%
Tier 1 Planned Capacity	2,605	533	-79.5%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	15,817	13,717	-13.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	15,817	13,717	-13.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	50.9%	29.6%	-21.3
Prospective Reserve Margin	50.9%	29.6%	-21.3
Reference Margin Level	19.0%	20.0%	1.0

WECC-CA			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	36,441	36,281	-0.4%
Demand Response: Available	743	666	-10.4%
Net Internal Demand	35,698	35,615	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,380	57,923	4.6%
Tier 1 Planned Capacity	4,757	6,997	47.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	60,138	64,920	8.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	60,138	65,920	8.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	68.5%	82.3%	13.8
Prospective Reserve Margin	68.5%	82.3%	13.8
Reference Margin Level	12.5%	12.5%	0.0

WECC-BC			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,966	11,936	-0.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	11,966	11,936	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,870	14,389	3.7%
Tier 1 Planned Capacity	433	637	47.0%
Net Firm Capacity Transfers	164	0	-100.0%
Anticipated Resources	14,467	15,026	3.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	14,467	15,026	3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	25.9%	5.0
Prospective Reserve Margin	20.9%	25.9%	5.0
Reference Margin Level	12.8%	11.4%	-1.5

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	1,983	1,977	-0.3%
Demand Response: Available	0	0	0%
Net Internal Demand	1,983	1,977	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,733	3,619	-3.0%
Tier 1 Planned Capacity	52	0	-100.0%
Net Firm Capacity Transfers	0	0	0%!
Anticipated Resources	3,784	3,619	-4.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,784	3,619	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	90.8%	83.1%	-7.8
Prospective Reserve Margin	90.8%	83.1%	-7.8
Reference Margin Level	12.5%	12.5%	0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	30,748	33,604	9.3%
Demand Response: Available	30	30	0.0%
Net Internal Demand	30,718	33,574	9.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,729	34,671	-10.5%
Tier 1 Planned Capacity	463	3,152	581.5%
Net Firm Capacity Transfers	0	6,136	100%!
Anticipated Resources	39,192	43,959	12.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	39,192	43,959	12.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	30.9%	3.3
Prospective Reserve Margin	27.6%	30.9%	3.3
Reference Margin Level	17.2%	17.2%	0.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,481	11,501	9.7%
Demand Response: Available	282	285	1.1%
Net Internal Demand	10,199	11,216	10.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	18,356	17,768	-3.2%
Tier 1 Planned Capacity	199	366	84.3%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	18,555	18,134	-2.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	18,555	18,134	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	81.9%	61.7%	-20.3
Prospective Reserve Margin	81.9%	61.7%	-20.3
Reference Margin Level	19.0%	18.2%	-0.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,844	21,147	1.5%
Demand Response: Available	340	177	-47.9%
Net Internal Demand	20,504	20,970	2.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,991	40,135	2.9%
Tier 1 Planned Capacity	3,381	2,733	-19.2%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	42,372	42,868	1.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,372	42,868	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	106.6%	104.4%	-2.2
Prospective Reserve Margin	106.6%	104.4%	-2.2
Reference Margin Level	16.0%	16.0%	0.0

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 and may vary widely year to year based on the identified risk hour. In many areas, winter demand peaks in the early morning hours or early evening resulting in little or no electrical resource output from solar PV resources and wide variability in wind availability. The following table shows the capacity contribution of existing wind and solar PV resources at the identified risk hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources On-Peak Capacity Contributions by Assessment Area

	Wind			Solar			Hydro		
Assessment Area/Interconnection	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	30,247	8,772	29%	13,726	686	5%	9,103	5,354	59%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	6,288	5,676	90%
MRO-SaskPower	816	433	53%	30	0	13%	884	703	80%
MRO-SPP	35,714	7,198	20%	1,197	457	38%	5,602	5,521	99%
NPCC-Maritimes	1,635	241	15%	155	10	6%	1,357	1,283	0%
NPCC-New England	2,675	455	17%	3,620	0	0%	3,742	1,453	39%
NPCC-New York	2,586	737	29%	627	0	0%	6,357	5,283	83%
NPCC-Ontario	4,943	1,971	40%	478	0	0%	8,763	6,824	78%
NPCC-Québec	4,024	1,426	35%	10	0	0%	41,014	39,501	96%
PJM	13,318	5,463	41%	15,732	1	0%	8,134	7,900	97%
SERC-Central	1,324	370	28%	1,576	455	29%	4,991	4,027	81%
SERC-East	0	0	0%	7,068	1,792	25%	3,010	2,951	98%
SERC-Florida Peninsula	0	0	0%	12,058	2,151	18%	0	0	0%
SERC-Southeast	0	0	0%	8,670	4,461	51%	3,258	3,258	100%
Texas RE-ERCOT	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC-AB	5,712	1,919	34%	2,206	0	0%	1,788	570	32%
WECC-Basin	5,932	1,148	19%	3,853	62	2%	5,334	2,946	55%
WECC-BC	747	85	11%	17	0	0%	35,504	27,119	76%
WECC-CA	9,382	682	7%	28,328	0	0%	31,479	9,143	29%
WECC-Mex	40	4	11%	350	0	0%	0	0	0%
WECC-NW	14,744	1,319	9%	4,695	1,556	33%	65,830	37,005	56%
WECC-RM	5,681	2,265	40%	3,521	0	0%	6,502	2,654	41%
WECC-SW	4,303	1,182	27%	12,139	391	3%	6,234	1,896	30%
EASTERN INTERCONNECTION	93,517	25,692	27%	64,937	10,013	15%	61,489	50,233	82%
QUÉBEC INTERCONNECTION	4,024	1,426	35%	10	0	0%	41,014	39,501	96%
TEXAS INTERCONNECTION	40,629	7,833	19%	35,609	660	0%	579	566	98%
WECC INTERCONNECTION	46,541	8,605	19%	55,108	2,008	4%	152,671	81,333	53%
INTERCONNECTION TOTAL:	184,711	43,556	23%	155,664	12,685	8%	255,753	171,633	67%

Review of Winter 2024–2025 Capacity and Energy Performance

The meteorological winter across the contiguous United States had an average temperature of 34.1 degrees F—1.9 degrees above average—ranking in the warmest third of NOAA's historical record. Total winter precipitation in the US was 5.87 inches, 0.92 of an inch below average, ranking in the driest third of the December–February climate record.[17] Most of Canada experienced temperatures at least 2°C above the baseline average with the Maritime provinces, southern Ontario, and the Canadian west coast recording temperature departures nearer the baseline average while a small region in southern Saskatchewan recorded temperatures just slightly below the baseline average.[18]

In February 2025, FERC and NERC and its Regional Entities launched a joint review of the BPS' performance during the January 2025 arctic events, which comprised Winter Storms Blair, Cora, Demi, and Enzo.[19] The week of January 19–25, 2025 was the third coldest winter week (spanning Sunday through Saturday) across the United States since 2000. Between January 21 and 22, 2025, natural gas demand peaked at 150 Bcf/day, electric demand peaked at 683 GW, and unplanned outages peaked at 71,022 MW. Nevertheless, during the January 2025 arctic events, manual load shed was not required. The January 2025 arctic events had lower observed hourly wind chill temperatures in pockets of the Northeast, the Louisiana Gulf, California, and the Southwest compared to Winter Storms Uri, Elliott, Gerri, and Heather. During the January 2025 arctic events, the most extreme storm relative to typical weather was Winter Storm Enzo—a Gulf and Southern storm. On January 20, 2025, a burst of snow, sleet, and freezing rain developed across Texas and Louisiana late in the day. A mixture of sleet and freezing rain fell from Austin to San Antonio and to the southernmost point of Texas. By the early morning hours of January 21, 2025, for the first time in history, a blizzard warning was issued for southwest Louisiana and the southeastern-most point of Texas. Snow fell in Gulf cities in Texas, southern Mississippi, southern Alabama, and western Florida. On January 21, 2025, Baton Rouge recorded 7.6 inches of snowfall, making it the city's snowiest day since recordkeeping began in 1892, while New Orleans saw its snowiest day on record, with a total of 8.0 inches. Temperatures plunged to single digits in Louisiana. Temperatures in some parts of the state fell to levels not seen in more than 125 years.

The review team engaged with 10 electric entities across the Eastern and Texas Interconnections to gather the information necessary to provide a high-level overview of the BPS' performance during the cold weather events. Based on the data and interviews that the team reviewed, electric generators appear to have performed better during the January 2025 arctic events because of additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations. The natural gas system also performed better overall, serving record levels of natural gas demand and experiencing only minor production declines and short-duration force majeure events.

On October 1, 2025, NERC submitted to the Federal Energy Regulatory Commission its first *Cold Weather Data Annual Report*. This report includes a review of forced outage data from GADS for the winter 2024–2025 period indicating performance consistent with historical performance as reported in NERC's annual *State of Reliability* report. This is within the normal range of capacity that occurs across the fleet. During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The outages occurring over January 20, 2025, were analyzed as part of the joint FERC, NERC, and Regional Entity *2025 System Performance Review*. The joint FERC, NERC, and Regional Entity *2025 System Performance Review* found a reduction in peak coincident unplanned generator outages for the four 2025 winter storms reviewed compared to past winter storms; however, this review also noted that it was not an exact comparison due to prior winter storms having different characteristics.

Eastern Interconnection–Canada and Québec Interconnection

No EEAs were needed during the previous winter season. One entity plans to make a slight increase to the demand-response program based on last winter's operations.

[17] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration
[18] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca
[19] https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional

Eastern Interconnection–United States

Several entities indicated that generators performed better during the January 2025 arctic events than in previous winter storms. For example, TVA stated that generator performance within its footprint was stable, with minimal natural gas delivery issues. Southeastern RC detailed that no major fuel-related outages occurred. FRCC noted that generator performance was strong during this period. The significant characteristics of Winter Storm Enzo in the Southern and Gulf states were freezing precipitation and snow accumulation, especially in regions where those conditions rarely occur. In FRCC, only the northern portion of Florida experienced severe arctic weather including freezing precipitation and snowfall (record-setting, in some cities) that were abnormal for the region even though certain northern cities have faced cold temperatures in the past. In Florida, entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events. ISO-NE, NYISO, and PJM all generally described the January 2025 arctic events as having cold temperatures but overall weather conditions that were similar to a winter without a major storm.

MISO emerged from Winter 2024–2025 without turning to emergency procedures despite the wide-ranging winter storms from January 6 to 9 and again from January 20 to 22. Generators continue to prioritize scheduling planned or maintenance outages to the shoulder seasons of fall and spring to maximize unit availability for the winter season. Also, extreme cold weather outage adders were added to the LOLE model to make sure that winter storm risks are included in planning. In PJM, demand reached a new all-time winter peak on January 22, 2025, of 143,714 MW with sufficient reserves. PJM did call an EEA1 on January 22, 2025, however reserves remained adequate. PJM had less than 3% load forecast error over the peak days of the January cold weather events. Reliability cases were conducted, and units with extended start times were evaluated and started early to ensure units were on-line before extreme cold weather settled in. PJM had a 9.24% forced outage rate on the peak day, a relatively low forced outage rate for the weather experienced. There were also very few gas production problems; however, market issues prevented proper scheduling because of the four-day holiday weekend.

In SERC-Central, entities reported only limited impacts from Winter 2024–2025 coldest weather and made minor adjustments. One entity declared conservative operations ahead of peak conditions but experienced no emergencies. One entity raised its winter Planning Reserve Margin target to 26% following lessons learned from Winter Storm Elliott. Corrective actions were implemented due to isolated equipment issues, including improved heat trace capabilities and adding heat trace equipment to the cold weather critical component list. During the previous winter season, some SERC-Florida Peninsula entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Despite these challenges, entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events.

Texas Interconnection–ERCOT

There were no energy emergencies for the Texas RE-ERCOT region last winter and no conditions that prompted changes in operating procedures. Winter Storm Kingston, which occurred in February 2025, was the only storm where ERCOT utilized firm fuel supply service resources (FFSS), a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard. A maximum FFSS deployment of 470 MW occurred on February 19 between the hours 13:10 and 17:02. Two other storms, Enzo and Cora, impacted ERCOT in January 2025, but these storms did not cause any system reliability issues.

Western Interconnection

Between January 11 and 17, 2024, a prolonged Arctic outbreak impacted British Columbia, Alberta, and the U.S. Pacific Northwest, driving record electricity demand and widespread reliability challenges. Four U.S. Northwest BAs and one Canadian BA declared energy emergencies, underscoring two core vulnerabilities: Inadequate capacity during evening peak hours (4 to 8 p.m.) and Insufficient fuel supply (limited hydro availability) across multiple days.

Although temperatures were comparable to the December 2022 cold snap, WECC-Northwest peak demand rose two percentage points to 6% over then, with BC Hydro and AESO both setting new all-time records. The U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies. California remained a net importer, providing little relief. Market prices in the Northwest reached or neared caps across most hours, indicating persistent scarcity rather than short-term peaks. Overall, the January 2024 event illustrated capacity alone does not ensure resilience. Sustained energy availability with interregional flexibility (both physical and market-based) will be key to maintaining reliability through the 2025–2026 and future winter seasons.

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	Jan. 21	18:00	108,888*	96,134 100,395	101,655	-977	18,468	16,761	0	519	17,010
MRO-Manitoba Hydro	Jan. 20	08:00	5.132	4,814 5,060	5,292	-277	142	52	N/A	0	146
MRO-SaskPower	Dec. 18	18:00	3,785	3,802 3,897	3,641	-231	664	368	0	3	0
MRO-SPP	Feb. 20	08:00	47,981	45,926 47,054	40,898	-1,424	4,886	4,783	255	36	9,272
NPCC-Maritimes	Jan. 22	07:00	5,810	5,907 6,498	4,266	-1,174	368	261	3	5	*
NPCC-New England	Jan. 21	18:00	19,607	20,308 21,814	17,686	-1,896	285	329	4	23	624
NPCC-New York	Jan. 22	19:00	23,521	22,998 24,023	18,932	-4,589	654	728	0	0	4,835

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
NPCC-Ontario	Jan. 22	18:00	21,940	20,951 22,179	24,250	2,990	3,693	1,914	0	0	*
NPCC-Québec	Jan. 22	08:00	37,178	36,061 39,545	39,514	-766	1,463	1,449	0	0	*
PJM	Jan. 22	09:00	144,420	130,712 144,939	152,142	7,731	3,704	3,620	3,076	1	8,663
SERC-C	Jan. 22	08:00	47,815	41,397 47,062	40,898	-6,921	563	176	214	455	1,538
SERC-E	Jan. 23	08:00	47,130	44,023 47,662	41,810	-5,323	0	0	145	2,526	1,830
SERC-FP	Jan. 25	08:00	43,974	45,714 54,239	41,702	-557	0	0	362	1,684	2,824
SERC-SE	Jan. 22	08:00	46,490	43,670 45,116	48,227	1,741	0	0	592	3,861	2,210

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
TRE-ERCOT	Feb. 20	08:00	80,560	73,193[5] 90,405[5]	79,960	-191	9,397	15,697	1,586	15	5,742
WECC-AB	Dec. 18	17:00	12,241	12,280 12,635	12,711	-470	3,175	1,867	4	0	*
WECC-BC	Feb 3	18:00	11,359	11,996 12,749	11,415	44	70	279	0	0	839
WECC-CA/MX	Dec. 12	15:00	35,555	35,359 36,823	31,925	-4,669	4,021	569	11,547	0	1,627
WECC-NW	Feb. 12	08:00	54,278	58,001 62,230	48,437	-920	2,607	7,876	1,494	2,198	3,281
WECC-SW	Feb. 13	16:00	22,969	16,177 17,777	25,087	2,117	2,741	1,065	1,599	182	1,496
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

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)

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 *2024–2025* WRA demand scenarios for each assessment area. Values are the normal winter 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 *2024–2025 WRA*.
[4] Values from NERC Generator Availability Data System for the 2024–2025 winter 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 2024–2025 winter risk period scenarios in the *2024–2025 WRA*.
[5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand scenarios found on p. 29 of the 2024-2025 WRA.
*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.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 144

FERC Staff Winter Reliability Assessment

Winter Energy Market and Electric Reliability Assessment

2025-2026

A Staff Report to the Commission

November 20, 2025

FEDERAL ENERGY REGULATORY COMMISSION

Office of Technical Reporting and Economics

Office of Electric Reliability

Preface

Slide 1

The 2025-2026 Winter Energy Market and Electric Reliability Assessment (Winter Assessment) provides Commission staff's outlook for this winter – December 2025 to February 2026. It focuses on energy markets and electric reliability. The report contains four main sections. The first summarizes the findings of the Winter Assessment. The second details the weather outlook for the upcoming winter. The third discusses notable considerations for the upcoming winter. The last section discusses energy market fundamentals, primarily natural gas and electricity supply and demand expectations.

The 2025-2026 Winter Assessment is a joint product from the Commission's Office of Technical Reporting and Economics and the Office of Electric Reliability.

Winter Outlook

Slide 2

Winter Outlook

- Slightly warmer conditions expected in the southern and eastern U.S.
- Natural gas prices 26% higher compared to previous winter despite increased production.
- Electricity demand growth supported by generation and transmission additions.
- Resources and operating reserves adequate in all NERC assessment areas for normal winter conditions.
  - Possible reliability challenges in ERCOT, NPCC-NE, SERC-Central, SERC-East, WECC-Basin, and WECC-NW in extreme winter conditions

Winter Outlook In Summary

This winter, slightly warmer temperatures are expected compared to last winter, potentially contributing to lower domestic natural gas and electricity demand. A prolonged cold weather event could still affect prices and availability of natural gas and electricity. Drought and elevated wildfire risk conditions are forecast to continue in multiple regions and could affect grid operating conditions and reliability.

Notwithstanding the forecasted slightly warmer temperatures, natural gas prices are expected to rise slightly compared to last winter. As of November 4, futures prices for the Henry Hub national benchmark averaged $4.39/Million British thermal units (MMBtu), 26% higher than winter 2024-2025 settled prices. Total U.S. natural gas demand is forecasted to exceed production this winter, as in previous winters, with the difference met by storage inventory withdrawals. While warmer weather could cause residential and commercial demand to decline, net exports are expected to continue their long-term growth trend. Natural gas storage inventories began the withdrawal season above the five-year average but marginally below the starting level of last winter, which was the highest since 2016. Overall natural gas storage inventories are forecasted to remain relatively robust throughout the winter.

Electricity markets will see generators add 56.1 GW of net winter capacity nationwide, compared to last winter, with 64.7 GW of new additions offset by 8.6 GW of retirements. Solar and batteries comprise 80% of new capacity additions, while coal and natural gas will account for 88% of retired capacity. Winter electricity consumption is projected to be 2.7% above the five-year average, with total monthly consumption expected to peak in January at 352 TWh. If realized, the projected consumption for this winter (1,035 TWh) will represent the second-highest level of the past five years, second only to last winter's record of 1,041 TWh.

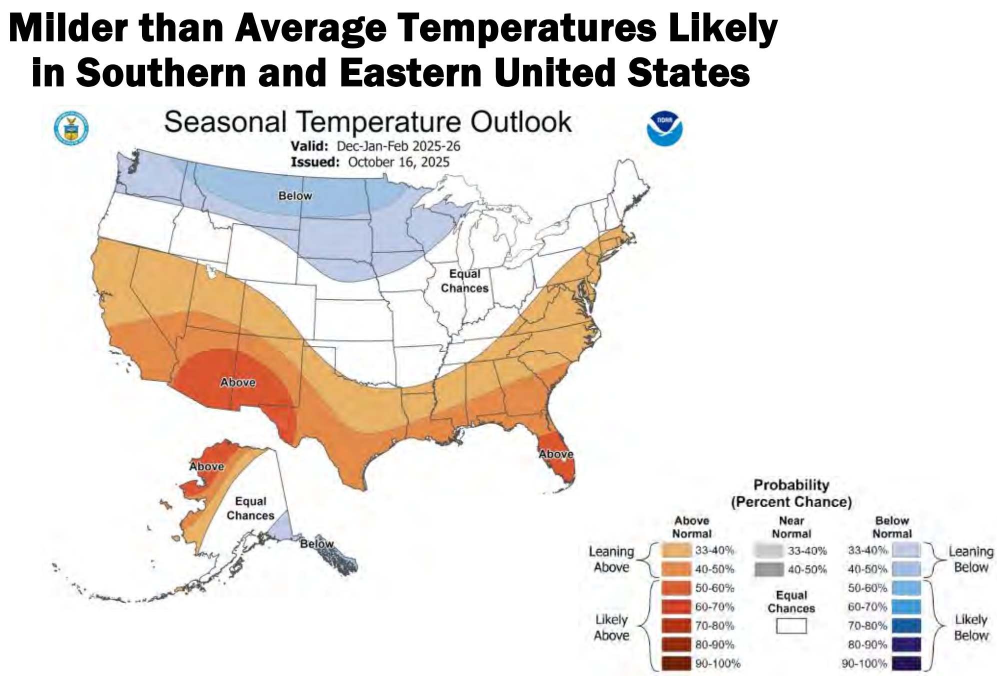
To support the grid, 3,132 new electric transmission projects totaling 19,008 miles of line will be available this winter. Of this total, 14,736 miles were placed in service between March and November 2025, with another 4,272 miles expected to be completed between December 2025 and February 2026. The primary drivers for these projects nationwide are storm and fire hardening (7,101 line-miles) and system reliability (4,238 line-miles), which together account for nearly 60% of all projected mileage. Other significant drivers include load growth (2,785 line-miles), asset renewal (2,738 line-miles), and generation interconnection (903 line-miles).

While the costs to produce electricity have remained relatively stable, in recent winters uplift payments have increased significantly during extreme weather or as a result of proactive operator actions taken to maintain reliability and continue to serve load.

Looking at the broader picture, all North American Electric Reliability Corp. (NERC) assessment areas are expected to have adequate generating resources to meet expected winter demand and operating reserve requirements under normal operating conditions. Under extreme weather conditions, the Electric Reliability Council of Texas (ERCOT), Northeast Power Coordinating Council-New England (NPCC-NE), SERC Reliability Corp.-Central (SERC-Central), SERC-East, Western Electricity Coordinating Council-Basin (WECC-Basin), and WECC-Northwest (WECC-NW) face a higher likelihood of tight generation availability, which may require operational mitigations to prevent potential reliability issues. However, NERC and the assessment areas have initiated various activities, such as readiness surveys of generators and facility inspections, to prepare for winter and increase the likelihood of their continued operation in the event of severe winter weather.

Weather

Slide 3



Weather Outlook

For the upcoming winter, the National Oceanic and Atmospheric Administration (NOAA) is predicting a weak La Niña phenomenon. La Niña refers to the large-scale, ocean-atmosphere climate phenomenon characterized by periodic cooling in sea-surface temperatures across the central and east-central equatorial Pacific. Based on the prediction, NOAA expects mildly wetter-than-average conditions in the northern Mountain West and Ohio River Valley regions and mildly drier-than-average conditions in the southern United States. As shown by the blue colors in the map on **Slide 3**, NOAA expects mildly colder-than-average temperatures in the Pacific Northwest and northern Midwest. The orange colors indicate mildly warmer-than-average temperatures along the East Coast, extending down through the South and West into the Desert Southwest and into California. The rest of the continental United States – shown in white – has equal chances of above or below average temperatures this winter. For its part, the U.S. Energy Information Administration (EIA) expects the population-weighted number of nationwide Heating Degree Days[1] in December, January, and February to decrease by 8% relative to last winter. This decrease reflects a slightly warmer winter nationwide.

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[1] Heating Degree Days are a measure of how cold a location is on a given day or during a period of days. A Heating Degree Day compares the mean (the average of the high and low)

It is important to note that NOAA's long-range predictions are dynamic and may change as more data becomes available. Furthermore, extreme winter storms, such as polar vortexes, are difficult to predict far in advance and are typically forecasted much closer to the event dates.

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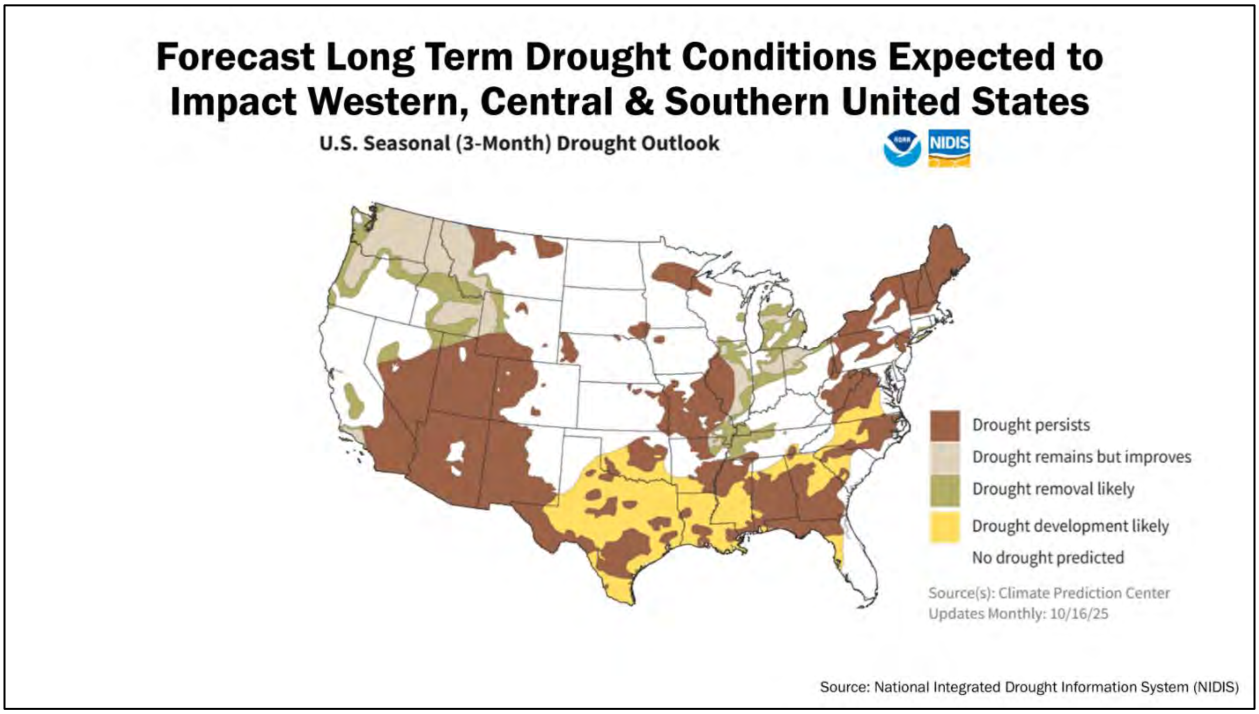
outdoor temperatures recorded for a location to a standard temperature, 65° Fahrenheit (F) in the United States. The colder the temperature, the higher the number of heating degree days. Natural gas is sometimes traded in a "Winter Strip" between November and March, which may have a different HDD forecast trend due to the two additional months.

Slide 4



Weather – Drought Condition Impacts

Drought conditions, illustrated by the dark brown areas in the map on **Slide 4**, persist across much of the western and central United States and are expected to continue into winter. If below-average snowfall, runoff, or conditions similar to this past spring occur this winter, significant impacts to water supplies in multiple basins are possible. Based on the La Niña forecast and current conditions, drought persistence is likely in the Southwest. This puts water basins in the southwestern United States at an especially high risk of water shortage impacts in early to mid-2026. In the South-Central and eastern regions of the United States, drought development, shown in yellow, is expected. Finally, minimal drought improvement, shown in tan and green, in the Pacific Northwest is also forecast for this winter.[2]

This winter, these dry conditions in the West are expected to reduce output from a significant portion of hydroelectric resources in WECC, including those in the Colorado River and Yakima Basins. Output in the Pacific Northwest will also continue to be limited. In early fall, reservoir levels throughout the western United States dropped sharply because withdrawals occurred at a greatly accelerated rate. For example, withdrawals in Utah were at twice the

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[2] NOAA, National Integrated Drought Information System, *The Western Drought Issue* (Sept. 3, 2025), https://www.drought.gov/news/western-drought-issue-2025-09-03.

typical rate and high withdrawals ended the water year[3] several weeks early in multiple irrigation districts in Washington state. If key headwaters do not receive above-average precipitation, it will not be possible to restore water supplies in the Pacific Northwest, Colorado and Great Basins to previous historical levels. The Colorado River Basin lost about 27.8 million acre-feet of groundwater between 2002-2024, roughly equal to the storage capacity of Lake Mead. As a result, water levels in Lake Powell are expected to fall into a lower balancing tier this winter, requiring reductions in output at the Glen Canyon Dam. Forecasts indicate that water levels could fall low enough to stop hydropower generation at the reservoir within the next year.[4] Impacts are also expected at downstream facilities, including at Hoover Dam, which is forecast to be in a Level 1[5] shortage condition this winter and fall to a Level 2[6] shortage by early spring 2026. This puts water basins in the southwestern United States at an especially high risk of water shortage impacts in early to mid-2026.

Also notable this winter, drought conditions are expected to continue in the central and southern United States. In the Mississippi River Basin, drought and extremely dry conditions have rapidly expanded due to above-average temperatures and low rainfall. As the region is entering what is typically a drier period, without significant and widespread rainfall, drought is expected to persist and expand across a significant portion of the Mississippi River Basin through December 31, 2025. For example, the Ohio River typically contributes 50% of the Mississippi River's flow. Recently, the Ohio River contribution fell to 8%.[7] These low water levels have impacted small hydroelectric facilities and restricted navigation, which could affect fuel transportation for some coal generators. Further downstream, low water levels on the Mississippi River may lead to the risk of saltwater intrusion and high-water temperatures, which could pose operational risks to thermal generators that use once-through-cooling

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[3] A water year is defined as October 1 to September 30 for surface water reports and water allocation planning.

[4] Bureau of Reclamation, *24-Month Study Inflow Scenarios* (Aug. 15, 2025), https://www.usbr.gov/uc/water/crsp/studies/images/PowellElevations.pdf.

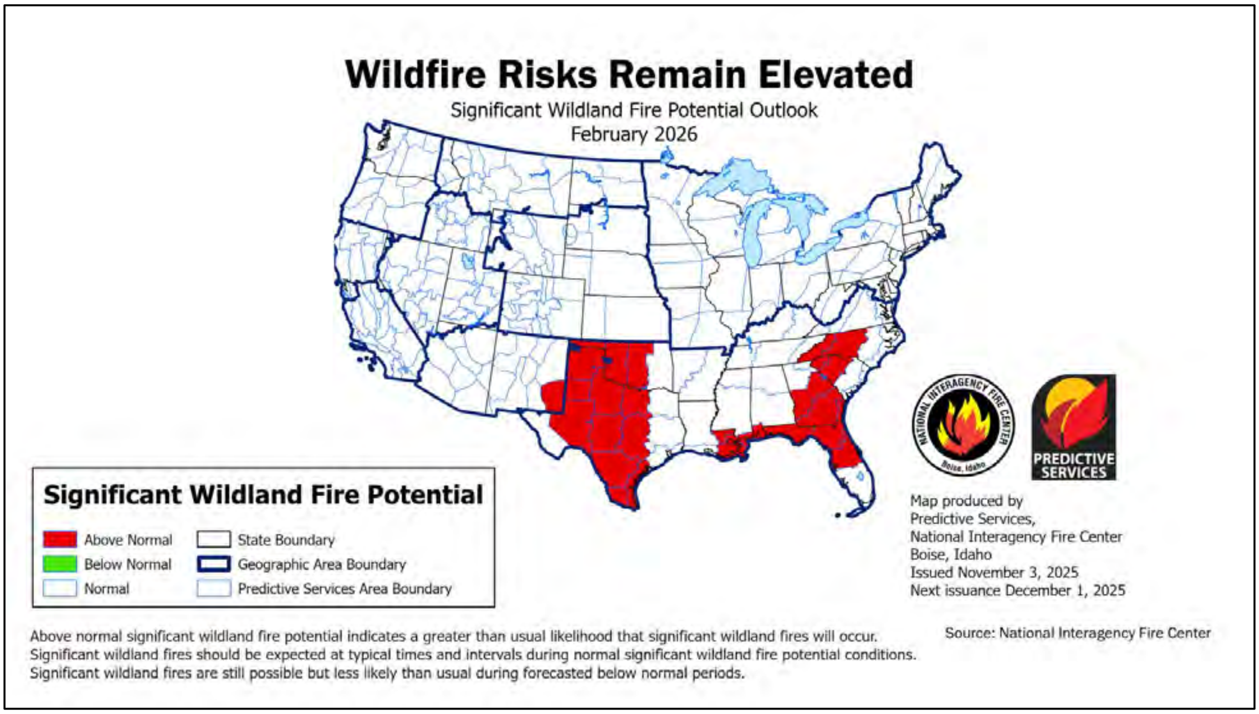
[5] A Level 1 Shortage Condition is triggered when Lake Meade's elevation falls below 1,075 ft. under the *2007 Interim Guidelines and the Lower Basin Drought Contingency Plan* and reduces total deliveries to 7.167 million-acre-feet.

[6] A Level 2 Shortage Condition is triggered when Lake Meade's elevation falls below 1,050 ft under the *2007 Interim Guidelines and the Lower Basin Drought Contingency Plan* and reduces total deliveries to 7.083 million-acre-feet.

[7] NOAA, National Integrated Drought Information System, *Drought and Water Update for the Mississippi River Basin* (Sept. 18, 2025), https://www.drought.gov/drought-status-updates/drought-and-water-update-mississippi-river-basin-2025-09-18.

equipment. While temperature and water level impacts are possible all along the river, salinity impacts are most likely for generators located in high-demand areas at the mouth of the river in southern Louisiana.

Slide 5



Weather – Wildfire Risk

Due to persistent high temperatures and a lack of rainfall in the western, central and southern United States, the risk of wildfires remains elevated in several states. Specifically, as indicated by the red areas on the map on **Slide 5**, risks remain elevated throughout Texas as well as in the Southeast from Louisiana to Florida and up through the Carolinas. These regions all experienced persistent drought, high temperatures, and dry conditions from late summer into fall. They experienced similar circumstances at the start of last winter.

This elevated wildfire risk can translate to significant infrastructure and operational risks for utilities. During dry conditions, utilities may temporarily turn off power to specific areas through a practice known as a public safety power shutoff. This is done to reduce the risk of electrical infrastructure starting a fire or to protect equipment from damage by nearby fires. While shutoffs have been used primarily in western states, they are now increasingly used in other regions to mitigate wildfire risk, including the central United States (South Dakota and Minnesota) and eastern states such as New Jersey. Wildfires can also cause significant electric transmission disruptions, potentially leading to extended outages due to damage to grid equipment or supporting infrastructure.

Notable Items

Slide 6

Notable Items

- Cold Weather Reliability Standards
  - Extreme Cold Weather Preparedness and Operations: EOP-012-3
  - Transmission System Planning Performance Requirements for Extreme Temperature Events: TPL-008-1
- Gas-Electric Coordination
  - Infrastructure vulnerabilities in key components
  - NPCC Northeast Gas/Electric System Study
  - ***Industries improving coordination; more progress still needed***
  - NAESB NOPR

Cold Weather Reliability Standards

As winter 2025-2026 approaches, NERC Reliability Standards for generator winterization plans are becoming enforceable, and new additional requirements will require generator owners and operators to implement plans to remain operational in extreme cold temperatures. This is a shift from the now-retired Reliability Standard EOP-012-2 (Extreme Cold Weather Preparedness and Operations),[8] which mandated that generator owners and operators develop and implement extreme cold weather preparedness plans by winter 2025-2026. Its successor, Reliability Standard EOP-012-3,[9] additionally requires existing generators to begin implementing their plans to operate at their calculated unit's Extreme Cold Weather

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[8] The purpose of this Reliability Standard was to address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its applicable generating units. *Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification*, 187 FERC ¶ 61,204 (2024).

[9] *Order Approving Extreme Cold Weather Reliability Standard EOP-012-3 and Directing Data Collection*, 192 FERC ¶ 61,229, at PP 34-37 (2025).

Temperature by October 1, 2025.[10] The Commission directed NERC to collect and submit generator owners' cold weather temperature reports detailing readiness for extreme conditions every May 15 beginning in 2025.[11]

Separately, Reliability Standard TPL-008-1 (Transmission System Planning Performance Requirements for Extreme Temperature Events) was approved earlier this year, with a phased implementation to begin in April 2026. Under this requirement, Planning Coordinators, in conjunction with their Transmission Planners, must conduct an extreme temperature assessment at least once every five years. These assessments evaluate future Bulk Electric System performance during extreme heat and extreme cold benchmark temperature events. The assessments required by this standard address a known reliability issue in which extreme temperatures cause operational failures by identifying vulnerabilities before those operational failures occur.[12]

Together, these standards will begin to help grid planners and operators anticipate and withstand any severe weather disruptions during winter 2025-2026.

Gas-Electric Coordination

Gas-electric coordination remains a critical focus for ensuring reliability across the electric grid, particularly during extreme cold weather events that could occur between December 2025 and February 2026. However, electric utilities, regional transmission organizations (RTOs), independent system operators (ISOs), and NERC have also taken actions to prepare for potential natural gas scarcity conditions based on lessons learned from past winter storms.

Cold weather vulnerabilities of natural gas infrastructure further compound risks to electric reliability. Cold weather-sensitive components such as electric-powered compressor stations and unprotected wellheads remain susceptible to freezing, and electrical or mechanical failures

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[10] Extreme Cold Weather Temperature refers to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated; NERC, Questions and Answers: Cold Weather Generator Data Request (Accessed Oct. 10, 2025), https://www.nerc.com/pa/comp/ColdWeatherGenDataDL/NERC_Cold_Weather_1600_DR_FAQ.pdf#:~:text=Extreme%20Cold%20Weather%20Temperature%20-%20The%20temperature,through%20the%20date%20the%20temperature%20is%20calculated.

[11] NERC, Questions and Answers: Cold Weather Generator Data Request (Accessed Oct. 10, 2025), https://www.nerc.com/pa/comp/ColdWeatherGenDataDL/NERC_Cold_Weather_1600_DR_FAQ.pdf#:~:text=Extreme%20Cold%20Weather%20Temperature%20-%20The%20temperature,through%20the%20date%20the%20temperature%20is%20calculated.

[12] *North American Electric Reliability Corporation*, 190 FERC ¶ 61,099, at PP 4-8 (2025).

at these points can disrupt natural gas deliveries to generating units during critical periods. While vulnerabilities at the production, gathering, and processing stages fall outside the Commission's jurisdiction, these vulnerabilities underscore the need for continued improvements in equipment winterization efforts and operational coordination.[13]

A study conducted by the NPCC, released on January 21, 2025, evaluated gas supply and pipeline constraints across New York and New England under extreme winter conditions. The study concluded that natural gas infrastructure in these regions is fully, or nearly fully utilized, during modeled cold weather events and found that any gas-side contingency, such as a pipeline disruption or a prolonged cold snap that affects gas production, could significantly stress the electric and natural gas systems and threaten electric grid reliability.[14]

On a positive note, the natural gas and electric industries have improved their coordination. For example, the performance of the Virginia-Carolinas Reliability Coordinator (VACAR) South region during the January 2025 Arctic cold wave illustrated notable gas-electric coordination.[15] According to a joint FERC-NERC report, improved performance in regions, including VACAR South, were made possible by enhanced coordination between pipeline operators and electric grid and generator operators, including proactive issuance of Operational Flow Orders[16] and real-time situational awareness calls.[17] Additionally, the same report highlights how natural gas infrastructure, including wellheads, compressor stations, and local distribution systems experienced minimal disruptions despite record-breaking demand of over 150 billion cubic feet per day (Bcfd). This marked improvement over previous winter storms was attributed to widespread winterization efforts and planned use of natural gas

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[13] FERC, NERC, and its Regional Entities (a joint staff report), *January 2025 Events: A System Performance Review* (April 17, 2025), https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional.

[14] NPCC, *NPCC Northeast Gas/Electric System Study* (Jan. 3, 2025), https://www.npcc.org/news/npcc-northeast-gas-electric-system-study.

[15] VACAR is a division within the SERC Reliability Corporation that includes systems located in Virginia, North Carolina and South Carolina. VACAR South are the VACAR companies that are not located in the PJM BA area.

[16] An Operational Flow Order is a directive issued by a natural gas pipeline operator to maintain the operational integrity of the pipeline system during periods of imbalance. It typically occurs when forecasted pipeline inventory, either too high or too low, threatens system reliability.

[17] FERC, NERC, and its Regional Entities (a joint staff report), *January 2025 Arctic Events: A System Performance Review,* at 12 (April 17, 2025), https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional.

storage assets. The Mountain Valley Pipeline, which was placed into service in 2024, also played a pivotal role in maintaining electric reliability in VACAR South by sustaining stable pipeline pressure during peak demand. Additionally, some dual-fuel generators switched to alternate fuels to maintain gas system balance, while battery storage was used to alleviate stress on both the electric grid and pipelines during critical hours. Collectively, these actions demonstrate how targeted collaboration, infrastructure hardening, and flexible energy resources are beginning to close long-standing coordination gaps between the gas and electric sectors.[18]

To further strengthen gas-electric coordination, the North American Energy Standards Board (NAESB) Wholesale Gas Quadrant (WGQ) recently updated business practice standards collaboratively developed by NAESB's gas, electric, and retail working groups.[19] The Commission issued a proposed rule on October 16, 2025, that proposes to incorporate by reference into the Commission's regulations certain modifications and one new standard to Version 4.0 of the NAESB WGQ standards. These proposed modifications aim to improve transparency and situational awareness across the gas-electric interface by requiring interstate natural gas pipelines to publicly post scheduled quantity information for power plants directly connected to the pipeline grid, including their location, affiliated RTO/ISO, and total scheduled volumes.[20]

In summary, while infrastructure vulnerabilities continue to challenge gas-electric coordination, enhanced collaboration between the gas and electric industries along with improved winterization efforts have begun to close critical reliability gaps. As the natural gas

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[18] *Id.* at 2.

[19] The NAESB Wholesale Gas Quadrant Business Practice Standards Version 4.0 Revised were jointly developed on a consensus basis by NAESB's Wholesale Gas Quadrant, Wholesale Electric Quadrant, and the Retail Market Quadrant. The Wholesale Gas Quadrant includes the following five co-equal segments: Producers; Pipelines; Local Distribution Companies; End-users; and Services. The NAESB Wholesale Electric Quadrant includes the following seven co-equal segments: Transmission; Generation; Marketers/Brokers; Distribution/Load-Serving Entities; End Users; Independent Grid Operators/Planners; and Technology and Services providers. The NAESB Retail Market Quadrant includes: Retail Electric Service Providers/Suppliers; Retail Electric Utilities; Retail Electric End Users/Public Agencies; and Retail Gas Market Interests. For more information on the NAESB Quadrant Segments and Subsegments see: https://www.naesb.org/pdf/quadrant_description.pdf.

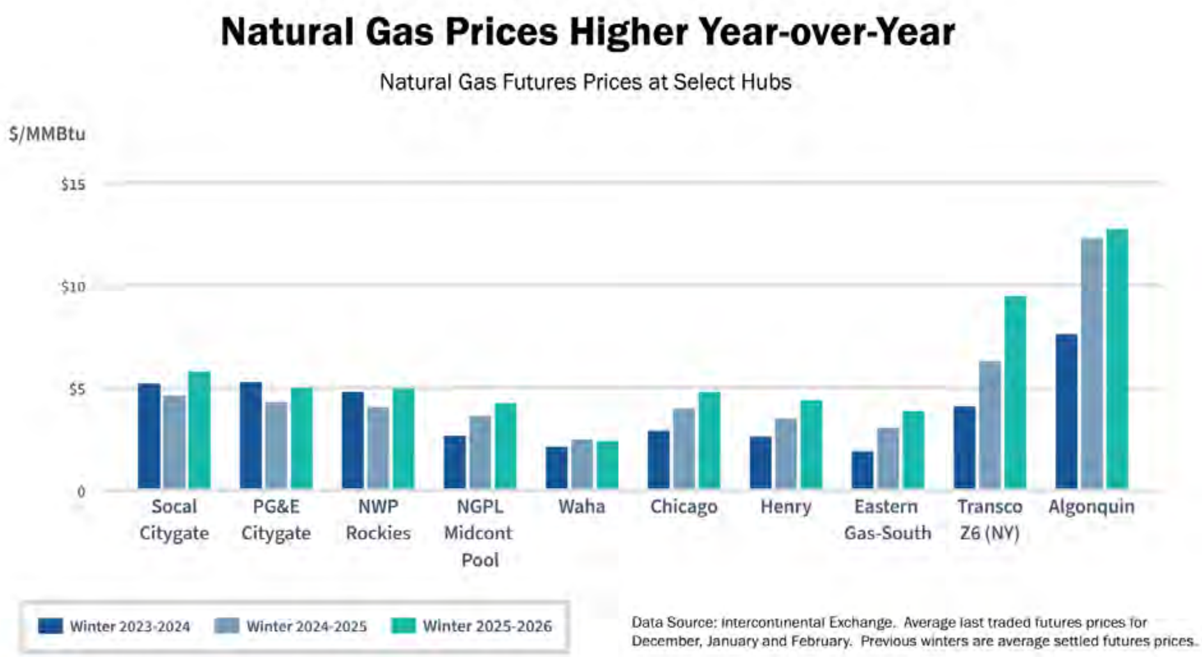
[20] *Standards for Business Practices of Interstate Natural Gas Pipelines*, Notice of Proposed Rulemaking, Docket No. RM96-1-044, (issued Oct 16, 2025).

and electric systems become more interdependent, sustained coordination between the two sectors will remain essential to safeguarding electric grid reliability.[21]

[21] For more on gas-electric coordination, see Chapter 3: Gas-Electric Interdependency, in FERC's *Energy Primer, a Handbook for Energy Market Basics,* http://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf.

Natural Gas Fundamentals

Slide 7



Natural Gas Prices

Natural gas futures provide expectations for natural gas prices at key hubs for the upcoming winter, as illustrated by the chart on **Slide 7**. The chart displays futures prices for three consecutive winters, with the light green bars representing futures prices for the upcoming winter (2025-2026) and the gray bars showing prices from last winter (2024-2025). In particular, natural gas futures in New England, New York, and California for winter 2025-2026 are currently trading higher than at other major hubs, and elevated natural gas demand is expected to drive prices higher on average across much of the United States. Heading into winter 2025-2026, higher natural gas futures prices at most major trading hubs across the United States are partly driven by rising futures prices at the Henry Hub national benchmark hub. **Slide 7** includes the Henry Hub, located in Louisiana, and nine other major supply and demand hubs in the Lower 48 States. As of November 4, Henry Hub futures averaged $4.39/MMBtu for this winter, up 26% from last winter's settled average of $3.49/MMBtu.[22]

[22] Natural gas futures prices are price quotations of contracts for the exchange of natural gas, as either a physical or financial settlement, at a specified time in the future. Winter futures prices in this section are the average quotes of the last traded futures contracts, as of November 4, 2025, for the winter months of December 2025, January 2026, and February

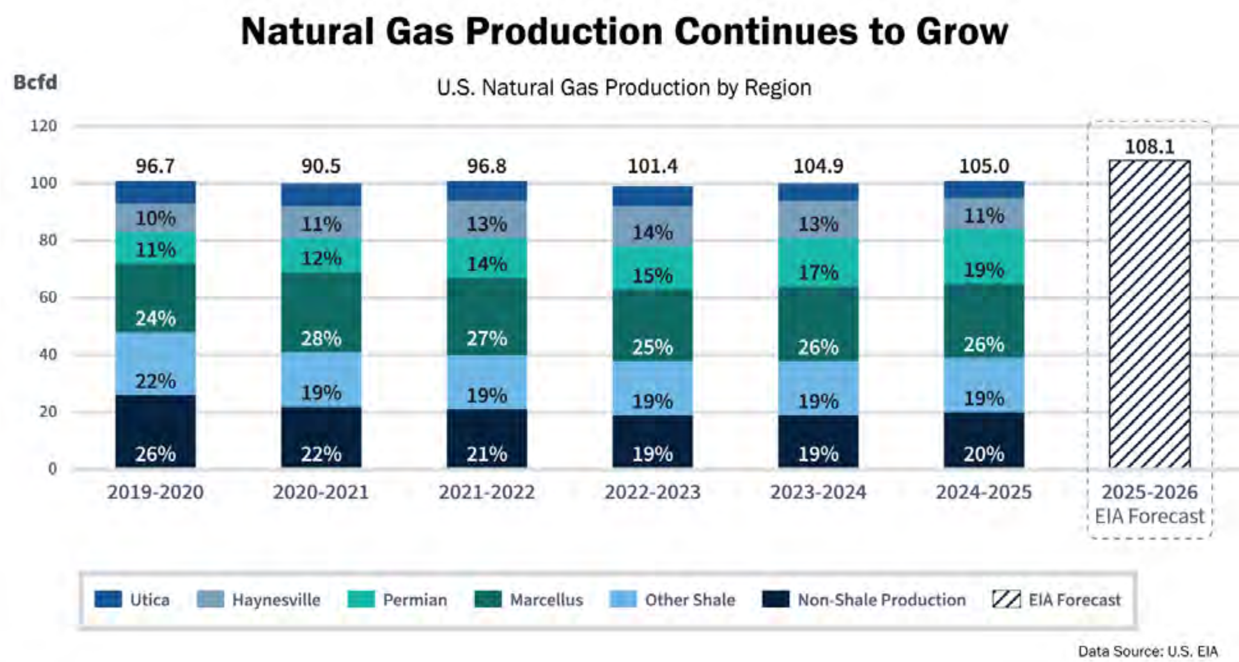
Rising demand for natural gas in the South-Central region, including from liquefied natural gas (LNG) export facilities, is contributing to higher commodity prices at Henry Hub, which operates as a benchmark for regional hub pricing.[23]

Consistent with previous winters, natural gas futures in New England, New York, and California for winter 2025-2026 are currently trading higher than at other major hubs. As shown in **Slide 7**, the Algonquin Citygates hub near Boston could see the highest prices in the country, averaging $12.76/MMBtu, a slight increase of $0.47/MMBtu from last winter's average. New England relies on imported LNG in the winter to help meet peak natural gas demand, and the region continues to compete for LNG volumes with Europe and Asia. Additionally, storage inventories in the East are currently 3% below last year's level and slightly below the five-year average. New York's Transco Zone 6 futures prices averaged $9.48/MMBtu, above last winter's average of $6.30/MMBtu, as that hub may face supply constraints this winter. California natural gas futures prices averaged $5.80/MMBtu at the SoCal-Citygate hub in southern California and $5.01/MMBtu at the PG&E-Citygate in northern California, both above last winter's levels by an average of $0.94/MMBtu. Infrastructure constraints continue to keep California natural gas prices among the highest in the country, but high regional natural gas storage inventories should help moderate price volatility this winter.

2026 as retrieved from InterContinental Exchange, Inc. Previous winter averages are the final settled futures prices for each month as retrieved from InterContinental Exchange, Inc.

[23] Regional natural gas prices are calculated by adding the Henry Hub winter futures price to the winter basis futures prices at major trading hubs in the United States. Regional basis prices reflect, among other things, the distance from producing basins, availability of natural gas transportation, and local weather expectations for the coming winter.

Slide 8



Natural Gas Production

Domestic natural gas production indicates the market's ability to meet U.S. demand this winter. As of October 7, 2025, EIA forecasted winter 2025-2026 dry natural gas production to average 108.1 Bcfd.[24] This represents a 2.9% increase from the winter 2024-2025 average of 105.0 Bcfd and is 7.7% higher than the five-year average. As illustrated on **Slide 8,** this reflects a fifth year of consecutive growth in production since winter 2020-2021, when the COVID-19 pandemic reduced natural gas production and demand. The different colored segments within each bar break down the total production by region, illustrating how various shale plays contribute to the overall volume.

Although overall natural gas production is projected to increase this winter, lower oil prices will suppress a subset of the production known as "associated gas," which is gas produced

[24] "Natural gas production" refers to dry production, or gross withdrawals less gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations. The term includes all quantities of gas used in field and processing plant operations.

through drilling activity in oil-rich basins.[25] Lower crude oil prices typically dampen drilling activity in such basins and—because their output is linked—reduce production of both oil and gas.[26] As of August 2025, there were 538 oil and natural gas rigs in operation, about 7% below the same time last year.

Over the past five winters, total U.S. dry gas production increased by at least 14.5 Bcfd in aggregate although occasional freeze-offs (freezing of oil and gas wells and pipes) reduced gas output during winter events, particularly Winter Storm Uri (2021), Winter Storm Elliott (2022), Winter Storm Heather/Gerri (2024), and the winter storms of January 2025. To prevent potential loss of production, the upstream natural gas sector has ramped up winter preparedness and equipment winterization efforts.[27] While winter storms are not directly comparable, operators reported fewer issues in winter 2024-2025, when Northeast natural gas production dropped only approximately 2 Bcfd, compared to 11 Bcfd that came off-line during Winter Storm Elliott two years earlier.[28] During the January 21-22, 2025 winter storm, the U.S. natural gas system mitigated reduced production from freeze-offs and unplanned outages and supported a record-setting peak domestic demand of 150 Bcfd without requiring load shedding by electric utilities.[29]

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[25] EIA, *Short-Term Energy Outlook*, at 9 (Sept. 9, 2025), http://www.eia.gov/outlooks/steo/archives/sep25.pdf.

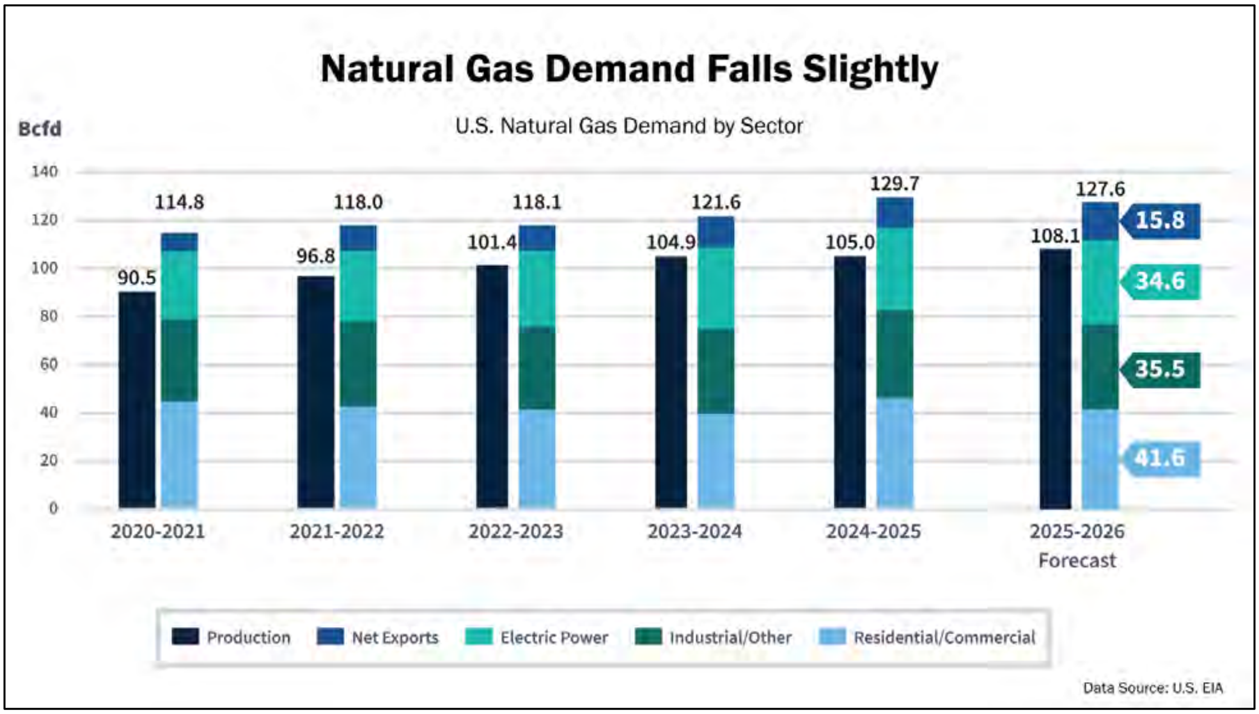
[26] Crude oil prices for West Texas Intermediate at the Cushing Interchange in Oklahoma, the U.S. crude oil benchmark, are expected to average $48.33 per barrel, 32.7% lower than the five-year average and 33.3% lower than the average winter 2024-2025 price of $72.46 per barrel. *See* EIA, *Short-Term Energy Outlook* (Sept. 9, 2025), https://www.eia.gov/outlooks/steo/data/browser/.

[27] American Gas Association, *Special Edition: Natural Gas Market Indicators – January 9, 2025* (Jan. 9, 2025), https://www.aga.org/research-policy/resource-library/special-edition-natural-gas-market-indicators-january-9-2025/.

[28] PJM Operating Committee, *Cold Weather Operations January 18–23, 2025,* at 22 (Feb. 6, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-15---january-2025-cold-weather-update.pdf.

[29] FERC, NERC and its Regional Entities (a joint staff report), *January 2025 Arctic Events: A System Performance Review,* at 1 (April 17, 2025). https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional.

Slide 9



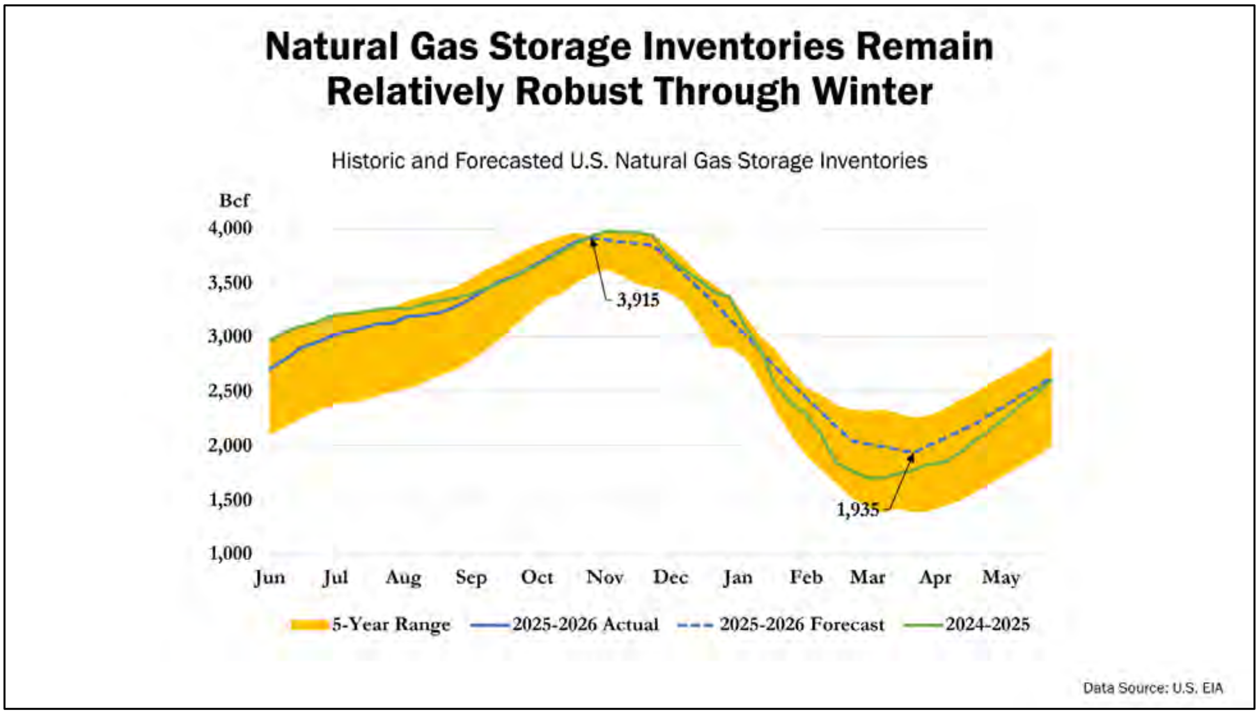
Natural Gas Demand

Total U.S. natural gas demand, represented by a core set of demand drivers, indicates the market need for natural gas this winter, as shown in the chart on **Slide 9**. Natural gas demand is forecasted to average 127.6 Bcfd in winter 2025-2026, 1.6% lower than the 129.7 Bcfd in winter 2024-2025. As the chart illustrates, total U.S. demand, represented by the height of the stacked bars, has grown over the last several years. Forecasted demand for winter 2025-2026 remains higher than the previous five-winter average by 5.6%. The different colored segments of each bar break down total demand into its components: residential, commercial, and industrial demand; natural gas consumed for electricity generation (power burn); and net exports. Total U.S. domestic natural gas consumption, which excludes net exports, is expected to average 111.7 Bcfd in winter 2025-2026, a decrease of 4.6% from winter 2024-2025 levels and a 2.1% increase from the previous five-winter average. Exports are discussed in greater detail in the *Natural Gas Exports and Imports* section below.

The light blue segment of the bar represents the residential and commercial sector, which is forecasted to comprise a 32.6% share of total U.S. domestic demand mostly for winter space heating. EIA forecasts the residential and commercial sector to consume 41.6 Bcfd, a decrease of 10.2% from the notably high demand seen during winter 2024-2025 due to the January 2025 winter events. Lower residential and commercial demand usually reflects a warmer winter, resulting in lower demand for natural gas used for space heating. The light green portion of the bar represents power burn, which comprises 27.2% of domestic demand and is expected to remain relatively flat compared to last winter, averaging 34.6 Bcfd in winter

2025-2026. Natural gas-fired generation is forecasted to provide 38.6% of total U.S. electricity generation output in winter 2025-2026, nearly the same as the 38.3% share in winter 2024-2025, but slightly higher than the previous five-winter average of 37.6%.

Slide 10



Natural Gas Storage Inventories

Natural gas storage inventories help to balance natural gas supply and demand and thus are fundamental to winter natural gas price formation. The chart on **Slide 10** illustrates the current storage forecast in the context of recent history. Traders and wholesale consumers watch storage inventories for signs of a supply and demand imbalance.[30] The solid and dashed blue lines on the chart tracks inventory levels for the current winter (2025-2026). The U.S. natural gas storage withdrawal season began in early November with 3,915 Bcf in working gas inventories. At the end of the withdrawal season on April 1, 2026, EIA currently forecasts 1,935 Bcf remaining in storage, as shown in **Slide 10**. The starting inventory level was above the five-year average of 3,811 Bcf but lower than the previous season (2024-2025) when the starting inventory level was the highest since 2016. The ending inventory level is expected to be slightly higher than the five-year average level and much above the previous withdrawal season's level (1,698 Bcf on March 6, 2025). EIA expects total withdrawals of approximately 1,980 Bcf throughout the 2025-2026 withdrawal season, 13% less than 2024-2025 winter withdrawals but 2.3% more than the previous five-winter average. As such, overall natural gas storage inventories are forecasted to remain relatively robust through winter.

Regionally, natural gas storage inventories in the East and Midwest are expected to start the winter withdrawal season approximately 3% below last year's level but just 1% below the five-

[30] U.S. natural gas storage inventory data listed in this section is for the Lower 48 states.

year average. The lower-than-average storage inventories in the East and Midwest are expected to be offset by storage levels higher than the previous five-winter average in the Mountain, Pacific, and South-Central regions.[31]

Generators fueled by petroleum and liquid fuels, such as distillate or residual fuel, provide a small portion of the overall electric generation capacity in the United States but play an important reliability role during critical periods in the Northeast.[32] As of October 31, 2025, distillate fuel oil inventories, which include heating oil, were at 111.6 million barrels for the United States,[33] 8.8% below the five-year average.

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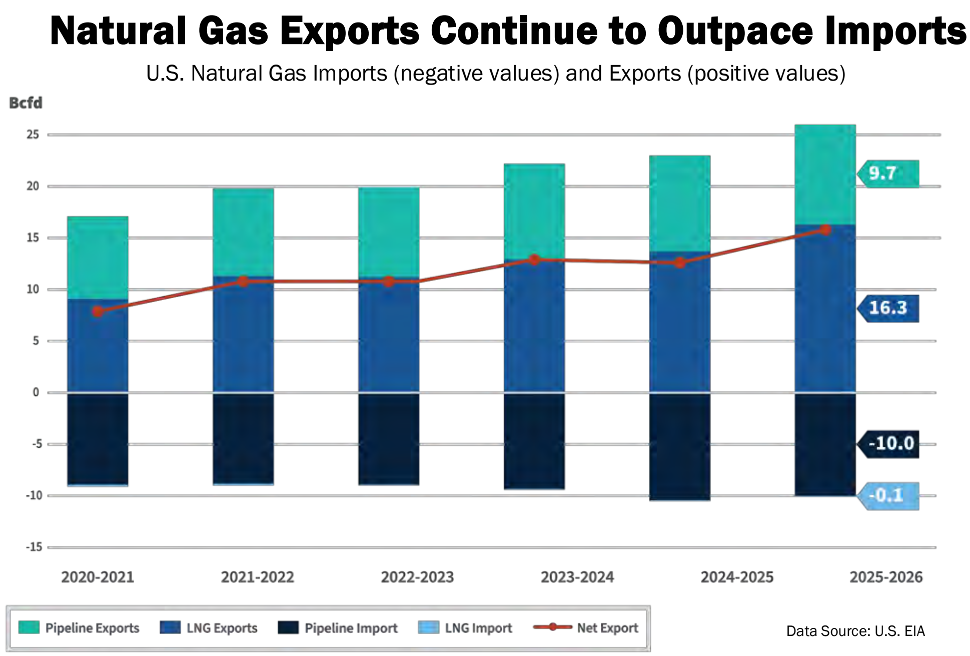
[31] For more on storage and its role in U.S. energy markets, see the Natural Gas Storage section (page 25) in FERC's *Energy Primer: A Handbook on Energy Market Basics,* http://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf.

[32] For more on oil and its role in U.S. electricity generation, please see Chapter 4: U.S. Crude Oil and Petroleum Product Markets in FERC's *Energy Primer: A Handbook for Energy Market Basics*, http://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf.

[33] EIA, Weekly U.S. Ending Stocks of Distillate Fuel Oil (Oct. 31, 2025), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=WDISTUS1&f=W.

Slide 11



Natural Gas Exports and Imports

Natural gas exports represent the fastest growing demand segment in the U.S. market and are expected to outpace natural gas imports this winter. The chart on **Slide 11** illustrates this trend, breaking down the volumes of U.S. natural gas LNG and pipeline imports and exports. The stacked bars are segmented to show the volume of LNG exports (in blue), pipeline exports (in light green), and pipeline imports (in black). Net natural gas exports are expected to increase this winter from last winter, primarily due to increased LNG export capacity from Calcasieu Pass LNG, Corpus Christi LNG Stage 3, and Plaquemines LNG, along with an expected increase in natural gas pipeline exports to Mexico. As seen in **Slide 11**, EIA forecasts U.S. gross LNG exports to average 16.3 Bcfd in winter 2025-2026, up 18.7% from winter 2024-2025. The United States remains the world's largest LNG exporter, with FERC-authorized liquefaction capacity in the Lower 48 United States expected to increase to 20.1 Bcfd by the end of the winter.[34]

While LNG imports play a minor (and declining) role in the U.S. gas balance, they are still important in pipeline-constrained New England. Additionally, some U.S. LNG export facility operators such as Cove Point in Maryland have allowed for the delivery of re-gasified LNG stored on site to provide additional supplies to market areas near export facilities during peak

[34] FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (Oct. 14, 2025), https://www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed.

winter demand days.[35] Altogether, the United States is expected to be a significant net exporter of natural gas this winter, with natural gas exports, including LNG and via pipeline, expected to exceed natural gas imports by an average of 15.8 Bcfd, compared to 12.6 Bcfd in winter 2024-2025.[36] This growth in net exports is represented by the blue line on the chart. Gross pipeline exports, including flows to both Canada and Mexico, are forecast to be 9.7 Bcfd, which is 0.3 Bcfd above average exports in winter 2024-2025. In total, the United States is a net gas importer from Canada and a net exporter to Mexico (via pipeline and trucks; the latter on a very small scale).

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[35] Cove Point's LTD-3 service allows shippers to liquefy domestic natural gas, inject LNG into storage, and then withdraw that stored LNG at any time. *See* Cove Point LNG, LP, FERC Gas Tariff, Tariff Record No. 1., Third Revised Volume No. 1., http://www.ferc.gov/sites/default/files/2020-05/066131_000110__contents.pdf.

[36] For more on LNG markets, see the Liquefied Natural Gas section (page 14) of FERC's *Energy Primer: A Handbook for Energy Market Basics,* http://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf.

Slide 12

Natural Gas Infrastructure Additions

- LNG Export Capacity Grows to 20.1 Bcfd
  - Two new projects in-service since start of last winter
- Pipeline Projects Added 2.2 Bcfd in Capacity in 2025
  - Additional capacity to support LNG export facilities
  - Increased takeaway capacity in the Southwest and Texas
- Natural Gas Storage Capacity Grows by 6.5 Bcf
  - New working gas capacity added in December 2024

Natural Gas Infrastructure

Natural gas infrastructure additions measure the growth in capacity used to process, transport, and store natural gas as it moves from initial production (or import) to ultimate delivery (including export). Natural gas infrastructure additions since last winter included expansions to export capacity, pipeline capacity, and storage capacity. New LNG export facilities and expansions are expected to bring peak LNG capacity to 20.1 Bcfd by the end of the winter. Pipeline projects placed in-service since last winter added 2.2 Bcfd of new transportation capacity, and an expansion project added 6.5 Bcf in new underground natural gas storage capacity.[37]

The United States was the world's largest LNG exporter in 2024, and U.S. natural gas exports are expected to increase again this winter, supported by two major projects completed since last winter.[38] Plaquemines LNG Phase 1 began operating in Louisiana in late 2024 and Corpus Christi LNG Stage 3 in Texas began in March of 2025, while Plaquemines LNG Phase 2 is

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[37] This calculation is based on EIA's pipeline project database cross-referenced with FERC certificate filings and in-service announcements. EIA, Natural Gas Pipeline Projects (July 2025), https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects_Jul2025.xlsx.

[38] EIA, *The United States remained the world's largest liquefied natural gas exporter in 2024* (March 27, 2025), https://www.eia.gov /todayinenergy/detail.php?id=64844.

expected to ship its first cargo in the fourth quarter of 2025. Including the new additions, by the end of the winter FERC-authorized U.S. LNG liquefaction capacity will be 20.1 Bcfd.[39]

Since November 2024, several interstate natural gas pipelines have increased pipeline capacity. Most notably, the Evangeline Pass Expansion Project Phase 2 entered service and increased the pipeline's total capacity to 2.2 Bcfd to deliver feedgas to Venture Global's Plaquemines LNG liquefaction and export facility. Several smaller pipeline expansion projects now in service are also expected to support production growth and demand, including the 0.19 Bcfd Texas to Louisiana Energy Pathway project which increases capacity between Haynesville production and Gulf Coast markets, and the 0.18 Bcfd East Lateral Xpress, which will supply the Plaquemine's LNG terminal.

Adding to natural gas storage capacity, the Tres Palacios Cavern 4 Storage Expansion project entered service in December 2024. Located in Texas, Tres Palacios Cavern 4 adds 6.5 Bcf of working gas capacity to the facility's existing 34.9 Bcf.[40] As a salt dome site, Tres Palacios can inject or withdraw gas quickly, supporting variable loads from a variety of users including LNG terminals.

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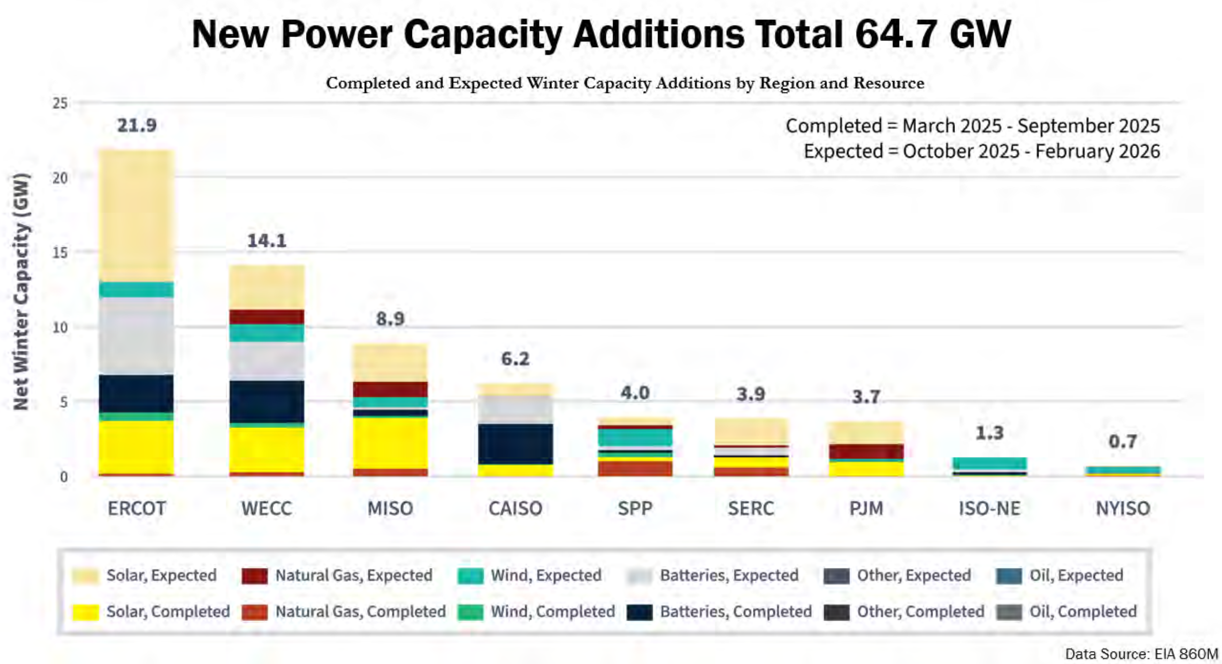
[39] EIA, U.S. Liquefaction Capacity (Sept. 17, 2025), https://www.eia.gov/naturalgas/data.php#imports; FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (Sept. 18, 2025), https://www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed.

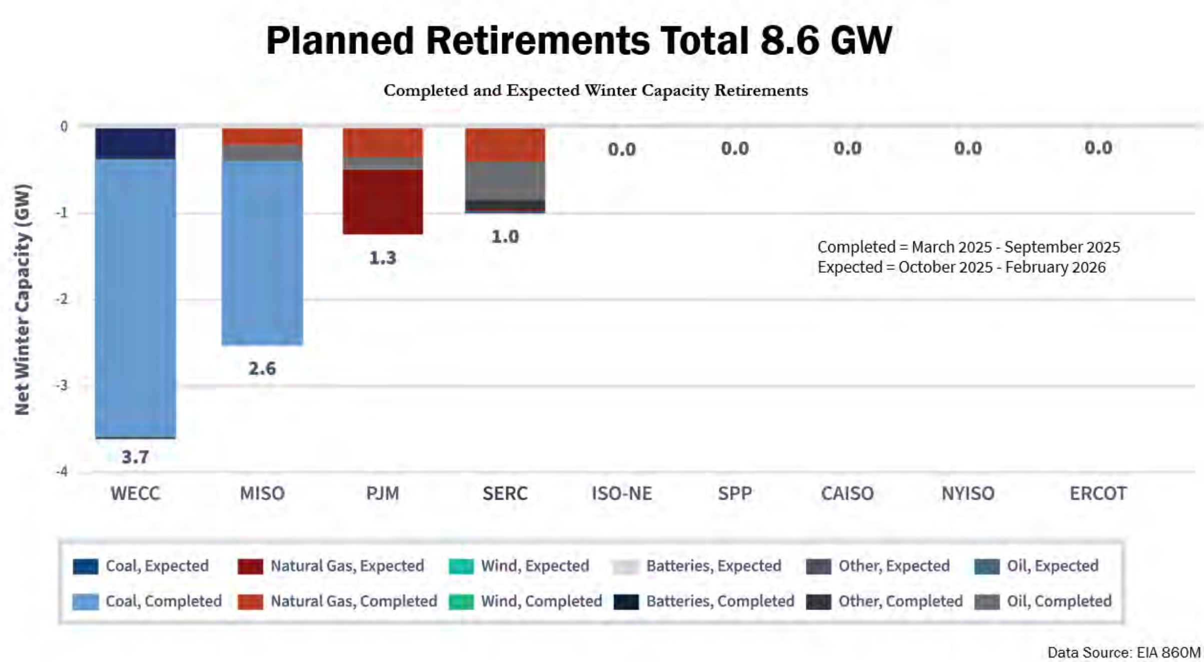
[40] Jodi Shafto, *Enbridge Ready to Bring on Fourth Cavern at Texas Natural Gas Storage Facility,* Natural Gas Intelligence (Nov. 22, 2024), https://naturalgasintel.com/news/enbridge-ready-to-bring-on-fourth-cavern-at-texas-natural-gas-storage-facility/.

Electricity Market Fundamentals and Electric Reliability

Slide 13



Slide 14



Electricity Generation Additions, Retirements, and Outages

Compared to last winter, the EIA projects the electricity sector will have 56.1 GW of additional net generation capacity this winter.[41] This net increase reflects 64.7 GW of new capacity additions offset by 8.6 GW of retirements. Of these capacity changes, 25.7 GW of additions and 2.4 GW of retirements were already completed between March and November 2025, while 39.0 GW of additions and 6.2 GW of retirements are expected to occur between December 2025 and February 2026. Given their operating characteristics, new capacity from solar, wind, or storage facilities does not replace the retired thermal capacity from coal, natural gas, or oil units on a one-for-one basis.

Capacity Additions

The chart on **Slide 13** breaks down the 64.7 GW of new winter capacity additions by region and resource type. Each vertical bar represents the total new capacity for a specific region, while the segments within each bar show the mix of different resources being added. In total, solar accounts for 50% (32 GW) of new capacity additions and batteries represent 30% (20 GW), with wind accounting for 11% (6.8 GW) and natural gas (6 GW) comprising the remainder. Solar represents the largest share of new capacity additions in PJM (68%) and MISO (67%). New battery capacity additions have continued to grow steadily from 695 MW in 2021 to a projected 11.5 GW in 2025. As the chart shows, western and central regions drive nearly 80% of overall capacity additions: ERCOT (21.8 GW), WECC (14.1 GW), the Midcontinent Independent System Operator (MISO) (8.9 GW), and the California Independent System Operator (CAISO) (6.2 GW).

Capacity Retirements

Capacity retirements are projected to total 8.6 GW, with coal-fired steam units representing 5.8 GW (67%) and natural gas units 1.8 GW (21%). The chart on **Slide 14** breaks down these figures by region and shows the specific fuel types being retired in each area. The majority of planned coal retirements are in WECC (3.2 GW) and MISO (2.1 GW), while the largest volume of planned natural gas retirements is in PJM (0.8 GW). The largest individual coal plant retirements include the Intermountain Power Project (1.8 GW) in Utah, J.H. Campbell Generating Complex (1.3 GW) in Michigan, and TransAlta's Centralia Generation Station (0.7 GW) in Washington. Notably, the J.H. Campbell plant's retirement is subject to a U.S. Department of Energy (DOE) emergency order extending its operation until February 17,

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[41] Net capacity additions and retirements data from EIA Form 860M show new generating capacity that entered service and existing capacity that retired during March 2025 through February 2026. The net increase represents total additions minus total retirements across all fuel types and technologies. *See* EIA (September 9, 2025) Form EIA-860M, https://www.eia.gov /electricity /data/eia860/

2026, to ensure grid reliability.[42] Similarly, the 397 MW oil-fired Wagner Unit 4 has been extended beyond its environmental run-hour limitations by a DOE emergency order until December 31, 2025, to help meet anticipated electricity demand in PJM.[43] In addition, DOE has ordered Units 3 and 4 of the Eddystone Generating Station to remain available through November 26, 2025, to minimize the risk of generation shortfalls in PJM.[44] Another notable coal retirement is the Merrimack Station in New Hampshire (460 MW). That plant ceased commercial operations in early October 2025, earlier than its previously planned 2028 retirement.[45]

Pace of Winter Capacity Changes

The pace of winter capacity additions has recovered after slowing in 2022. Capacity additions fell from 37.4 GW in 2022 to 32.7 GW in 2023, a 13% decline. Since then, the pace of capacity additions has rebounded strongly, reaching 42.6 GW in 2024 and 52.6 GW in 2025. Projected additions for 2026 are 64.7 GW, which would represent the largest annual capacity addition in over a decade. Conversely, the pace of generation retirements has slowed significantly following a surge in coal plant closures. Annual retirements peaked at 17.8 GW in 2023, then declined to 15.7 GW in 2024 and 8.6 GW in 2025—a 51% reduction from the 2023 peak. Retirements are projected to remain at similar levels in 2026 at 8.7 GW, consistent with this return to more moderate retirement rates.

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[42] Additional DOE orders could potentially delay other planned retirements this winter. U.S. Department of Energy, Order No. 202-25-9, Federal Power Act Section 202(c): Midcontinent Independent System Operator (Nov. 18, 2025), https://www.energy.gov/sites/default /files/2025-11/Order%20No%20202-25-9.pdf. *See* also U.S. Department of Energy, Order No. 202-25-7, Federal Power Act Section 202(c): Midcontinent Independent System Operator (Aug. 20, 2025), https://www.energy.gov/ceser/federal-power-act-section-202c-midcontinent-independent-system-operator-miso-0.

[43] *See* U.S. Department of Energy, Order No. 202-25-6A, Federal Power Act Section 202(c): PJM Interconnection (PJM) (Oct. 24, 2025), https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection-0

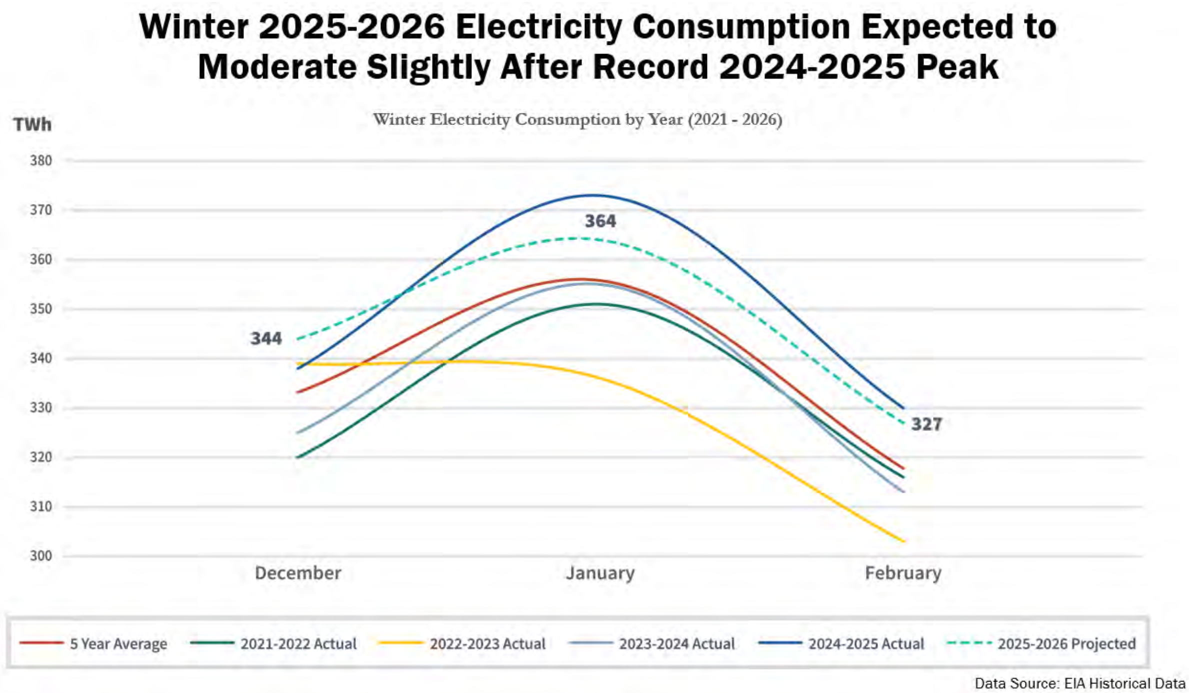
[44] *See* U.S. Department of Energy, Order No. 202-25-8 Federal Power Act Section 202(c): PJM Interconnection (PJM) (August 28, 2025), https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection-pjm.

[45] Retirement data is based on EIA-860M reported retirement dates. Some units, such as J.H. Campbell, continue operating under DOE emergency orders (202(c)) beyond their reported retirement dates, while others, such as the Merrimack Station, retired earlier than planned. Actual operational status may differ from reported retirement timing.

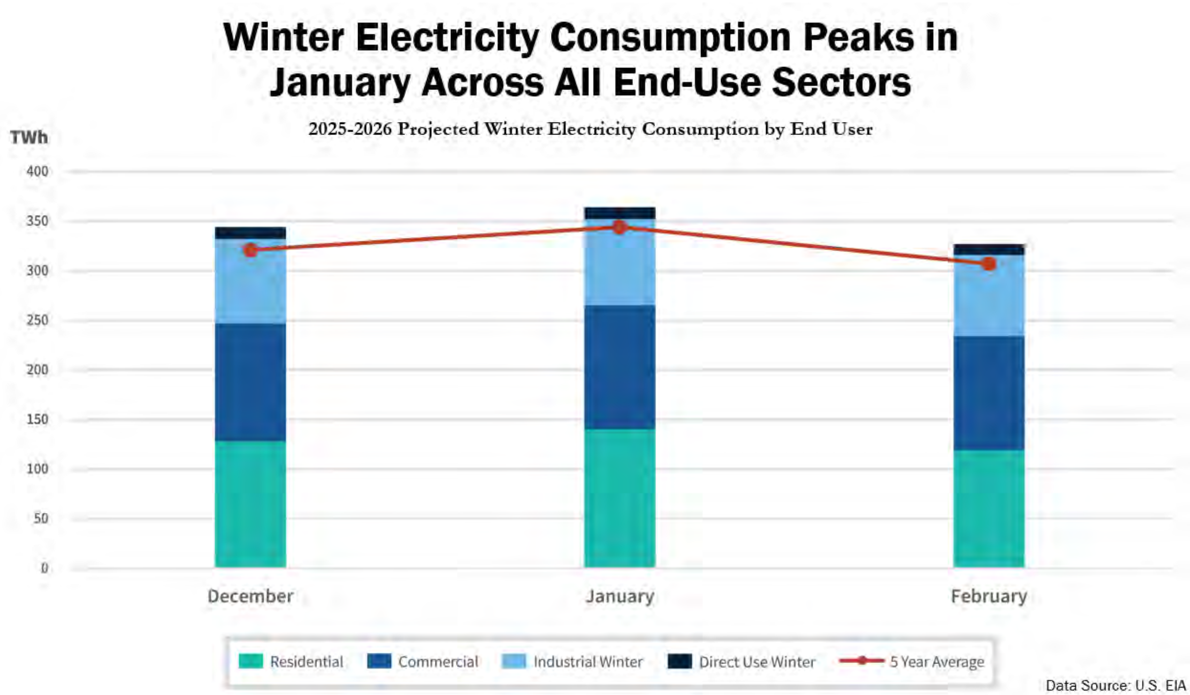
Planned Generation Outages

Oconee Nuclear Station Unit 3 (859 MW) in South Carolina is scheduled for a 28-day maintenance outage starting November 1, 2025. While the unit is scheduled to return to service before December 2025, any delays could reduce available capacity in the SERC region, emphasizing the importance of proactive grid management strategies for the winter season.

Slide 15



Slide 16



Electricity Consumption

EIA projects total winter electricity consumption to reach 1,035 TWh, or 2.7% above the five-year average of 1,007 TWh.[46] The chart on **Slide 15** provides historical context for this forecast, plotting projected consumption for winter 2025-2026 (the dashed green line) against the previous four winters. Among the last five winters, winter 2024-2025 represents the record peak at 1,041 TWh (3% above the five-year average), while winter 2025-2026 projections show more modest growth at 1,035 TWh, which would represent the second-highest consumption level of the five winters analyzed.

The breakdown of this electricity consumption by end-use sector for winter 2025-2026 is shown on **Slide 16**. The residential sector is projected to have the highest consumption at 387 TWh, followed by the commercial sector at 359 TWh and the industrial sector at 254 TWh. The stacked bars on the chart illustrate this monthly breakdown and show that consumption across all sectors is expected to peak in January, reaching a high of 352 TWh. The commercial sector is projected to see the strongest growth at 5% above its five-year average. Direct Use represents approximately 3% of total electricity consumption (or 35 TWh) and is expected to remain stable.[47]

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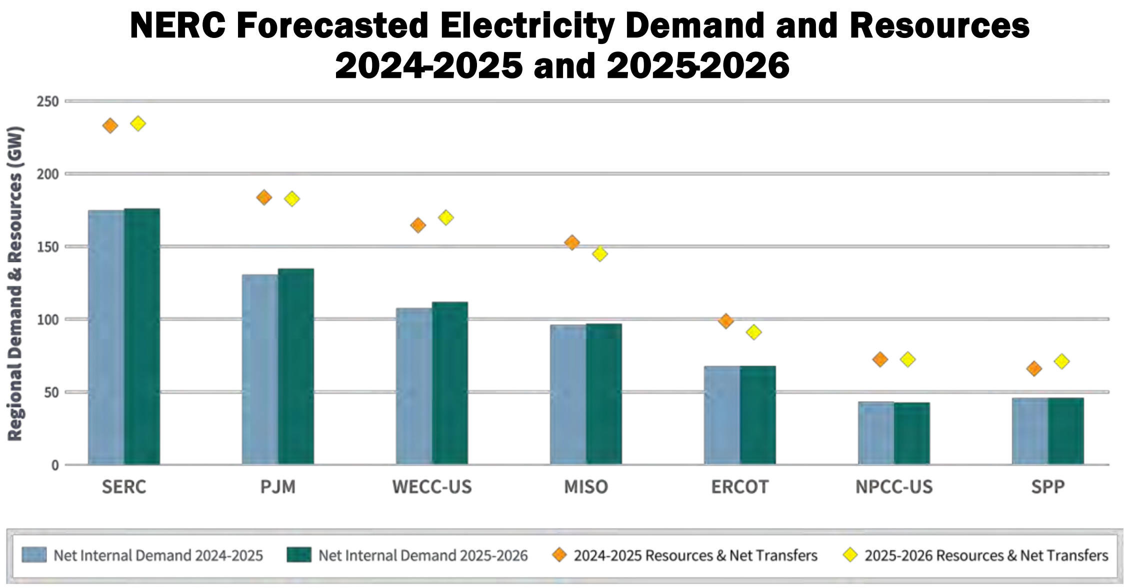
[46] EIA's *Short-Term Energy Outlook* (STEO) provides data and forecasts for U.S. electricity consumption retail sales to customers, broken down by residential, commercial, and industrial sectors. EIA, *STEO*, at Table 7A (Sept. 2025), https://www.eia.gov/outlooks/steo/archives/sep25.pdf.

[47] According to EIA, Direct Use represents "commercial and industrial facility use of onsite net electricity generation; and electrical sales or transfers to adjacent or colocated facilities for which revenue information is not available." See EIA, *STEO*, at Table 7A (Sept. 2025), https://www.eia.gov/outlooks/steo/archives/sep25.pdf.

Slide 17



NERC, 2025-2026 Winter Reliability Assessment
Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load.

NERC Forecasted Electricity Demand and Resources

According to NERC, electricity demand is expected to be higher this winter compared to last winter. NERC forecasts net internal demand[48] for electricity to increase by approximately 1.6%, or 11 GW, from 666 GW in winter 2024-2025 to 677 GW in winter 2025-2026. Actual electricity demand will depend on a number of factors, including the number, duration, and characteristics of extreme winter events.

Slide 17 shows the net internal demand as solid bars and the available resources and net transfer values (a combination of internal resources and additional external resources available to the region) as diamonds.[49] Despite the increased demand projected for Winter

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[48] Forecasted Net Internal Demand: Total of all end-use customer demand and electric system losses within specified metered boundaries, reduced by the projected impacts of Controllable and Dispatchable Demand Response programs.

[49] "Resources and Net Transfers" refers to the addition of "Existing-Certain Capacity" and "Net Firm Capacity Transfers." Existing-Certain Capacity includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct. Net firm capacity transfers refers to the imports minus exports of firm contracts. NERC*, 2024 Long Term Reliability Assessment* (December 2024, updated July 15, 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%2

2025-2026, all 15 U.S. NERC assessment areas are anticipated to have sufficient available generation resources and net transfers to meet their expected loads under normal winter conditions.[50] According to data from NERC,[51] planning reserve margins[52] exceed the reference reserve level margins[53] for the 15 NERC assessment areas. Even with expected ample planning reserve margins, regions can face tighter-than-expected supply if operating conditions deviate significantly from those expected for this winter. Planning reserve margins are a metric, but do not guarantee reliable operations at all times. For instance, they do not necessarily account for all extreme winter conditions that can lead to fuel unavailability for generators, derates of electric generators, unexpected generator outages, transmission outages, reduced power transfers from adjacent areas, delays in energy

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0Term%20Reliability%20Assessment_2024.pdf; *see also* Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load. NERC, *2025-2026 Winter Reliability Assessment,* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[50] The 15 U.S. assessment areas, also shown in **Slide 20**, are the NPCC-New England and NPCC-New York subregions of NPCC-US; PJM Interconnection L.L.C. (PJM); the SERC-Central, SERC-East, SERC-Southeast, and SERC Florida Peninsula subregions of SERC-US; MISO; SPP; the Texas Reliability Entity-Electric Reliability Council of Texas (TRE/ERCOT); and the WECC-NW (Northwest), WECC-SW, WECC-Rocky Mountain, WECC-Basin and WECC-CAMX subregions of WECC-US. NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[51] NERC *2025-2026 Winter Reliability Assessment* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[52] The planning reserve margin is the primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile. NERC, *2024 Long Term Reliability Assessment, at 138* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[53] Also known as a target reserve margin, the reference reserve level margin is provided by the region/subregion based on load, generation, and transmission characteristics as well as regulatory requirements. If not provided, NERC assigns a 15 percent reserve margin. NERC, Reliability Indicators, Metric 1-Reserve Margin (accessed Oct. 22, 2025), https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

resources coming online, and other factors that system operators must manage to maintain electric supply and reliability. In extreme scenarios, ERCOT, NPCC-NE, SERC-Central, SERC-East, WECC-Basin, and WECC-NW face a higher likelihood of challenges, which may require operational mitigations to avoid facing potential reliability issues. More comprehensive reliability assessments for these assessment areas are presented in the *Regional Highlights* section of this assessment.

To serve demand in winter 2025-2026, NERC forecasts a national decrease of 0.48%, or approximately 4.6 GW[54], in total electric generation capacity and net energy transfers from approximately 971.5 GW in winter 2024-2025 to approximately 966.8 GW in winter 2025-2026,[55] illustrated as diamonds in **Slide 17**.[56]

A forecast of the United States' electricity demand shows a significant upward trajectory.[57] This demand increase is driven by a combination of industrial sector recovery, electrification, and new demand from data centers and manufacturing. Currently, the size and speed with which data centers and crypto mining facilities can be constructed and connected to the grid presents unique challenges for demand forecasting and planning.[58] Data center demand alone

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[54] To determine these figures, using data provided in the "Demand and Resources Table of the NERC 2025-2026 Winter Reliability Assessment for each United States' assessment area, the Existing-certain capacity is summed across NERC assessment areas and the net firm capacity transfers projections are summed across all assessment areas, and compared to the same assessment area projections provided in the "2024-2025 WRA columns." The Existing-certain capacity and net firm transfers were described in FN 47 above Note that NERC's projected 4.6 GW decrease in generation capacity differs from EIA's anticipated 56.1 GW net increase in generation capacity because EIA estimates expected retirements and planned capacity through February 2025 based on data submitted to the annual EIA-860 and includes operating, out of service or on standby generators, as well as planned and not yet in operation generators. The EIA data is not directly comparable to the NERC data.

[55] NERC, *2025-2026 Winter Reliability Assessment* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[56] *Id.*

[57] *Grid Strategies LLC, Strategic Industries Surging: Driving US Power Demand, (Dec. 2024), https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf.*

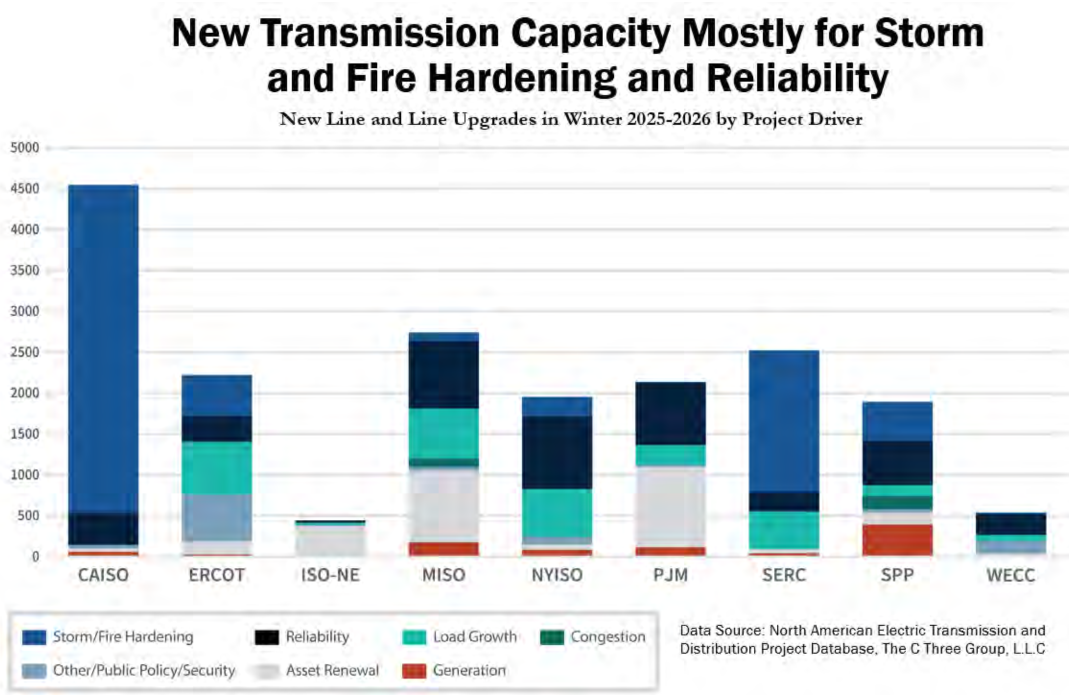
[58] NERC, *2024 Long-Term Reliability Assessment* at 8 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

is projected to consume over 5% of the total U.S. power demand for 2025, up from 4.4% in 2024.[59]

This increase in demand, in combination with the decrease in supply, is pressuring utilities to accelerate infrastructure upgrades and energy resource deployment, and to reconsider scheduled resource retirements to maintain grid reliability, such as those described further in the *Electricity Generation Additions, Retirements, and Outages* section above.

[59] Lawrence Berkeley National Laboratory, *2024 United States Data Center Energy Usage Report* at 52 (Dec. 2024), https://escholarship.org/uc/lbnl.

Slide 18



Electricity Transmission Projects

There are 3,132 new transmission projects supporting grid reliability this winter, including 1,551 substation-only projects, 1,070 transmission line projects, and 511 combined projects. These projects total 19,008 line-miles, with 14,736 miles already completed and placed in service between March and November 2025, and 4,272 miles expected to enter service between December 2025 and February 2026.[60] The chart on **Slide 18** breaks down these new line and line upgrades by region and project driver. Nationwide, the primary drivers for these projects are storm and fire hardening (7,101 line-miles) and system reliability (4,238 line-miles), which together account for nearly 60% of all projected mileage.

By project count, ERCOT (771), MISO (655), and PJM (610) are the most active regions for transmission development. As the chart illustrates, the top drivers vary by region: ERCOT is primarily focused on storm and fire hardening (23% of its line-miles) and load growth (29%), MISO is driven by a combination of asset renewal/aging infrastructure (32%) and system reliability (30%), PJM's development is concentrated on asset renewal/aging infrastructure

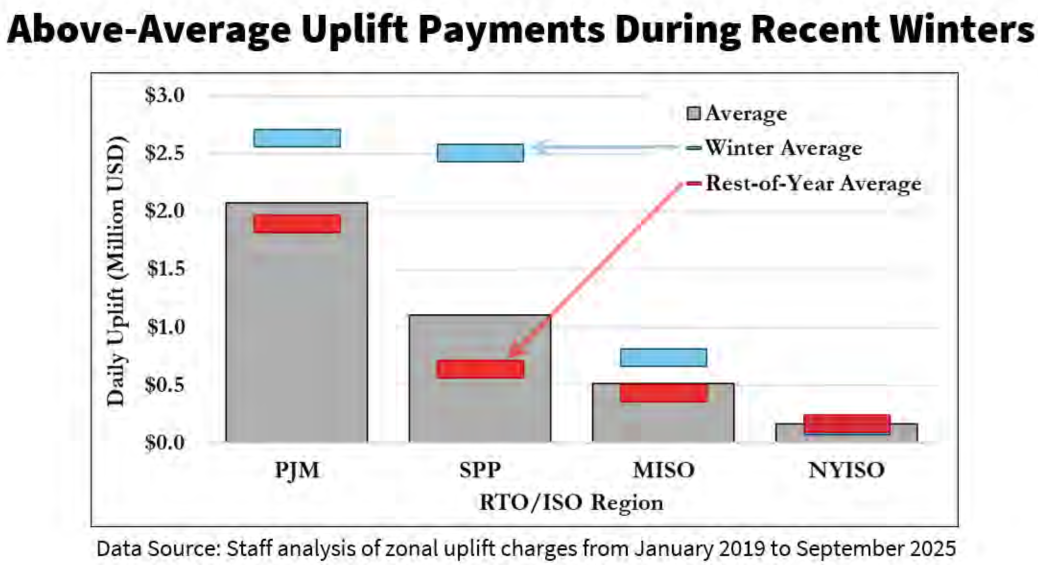
[60] Data on transmission line-miles is from The C Three Group's (Yes Energy) Electric Transmission and Distribution database. The projects listed in this report are limited to those placed into service between March 2025 and February 2026 that have one of the following statuses: conceptual, early development, advanced development, under construction, partial operations, or operating. Project terminology and the level of detail can vary significantly by region, which may result in incomplete data.

(46%) and system reliability (36%), and over 97% of CAISO's new mileage is for storm and fire hardening. Notably, all projects specifically developed for congestion relief are located in SPP and MISO, totaling 260 line-miles.

Most projects involve lines below 230 kV, accounting for 16,732 line-miles or 88% of total line-miles. For lines of 230 kV or higher, there are 2,277 line-miles or 12% of total mileage. The highest voltage lines of 500 kV or more account for 358 line-miles, primarily in CAISO (256 line-miles), WECC (91 line-miles), and MISO (7 line-miles).

Substation-only projects represent nearly half of all transmission infrastructure work this winter, with ERCOT (404 substations), MISO (320), and PJM (294) leading in substation development.

Slide 19



Electric Market Uplift Payments

Uplift payments in organized markets reflect the portion of the cost of reliably serving load that is not included in market prices. They compensate generators that are dispatched to operate but whose market revenues fail to cover their production costs. The costs of uplift payments are typically allocated among grid customers. For this coming winter, forecasted natural gas prices and electricity demand suggest that the cost of producing electricity will not be appreciably higher than that of recent winters.[61] But, unpredictable periods of extreme winter weather could still drive up both wholesale electricity prices and uplift payments for some days.

The chart on **Slide 19** illustrates this historical trend, visualizing how average daily uplift payments during the winter are typically higher than the average for the rest of the year across several grid regions.[62] Historical data shows that daily uplift payments have been higher on

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[61] EIA, *Short-Term Energy Outlook* (Oct. 7, 2025), showing that the wholesale electricity outlook for the coming winter has average wholesale electricity prices that are close to historical winter averages, except January where prices are expected to increase slightly. https://www.eia.gov/outlooks/steo/archives/oct25.pdf.

[62] Assessment in this report of zonal uplift payments are based on publicly available data obtained from datasets and market reports published by the ISO/RTOs from Jan. 1, 2019, to Aug. 31, 2025, for NYISO, MISO, and SPP and July 1, 2019, to Aug. 31, 2025, for PJM.

average during recent winters in several regions, driven by two key factors: extreme weather events and specific operator actions.[63]

- **Extreme Weather:** During an eight-day period of Winter Storm Uri in February 2021, total uplift payments exceeded $1.13 Billion in SPP and $160 million in MISO. The daily payments in SPP during the storm averaged over $140 million—more than 100 times the region's typical daily average since 2019.
- **Operator Actions:** Proactive operator decisions can also drive uplift. In January 2025, PJM's commitment of specific resources in advance of cold weather resulted in nearly $340 million in uplift payments across five days.[64] Such actions ensured system reliability,[65] but at the expected cost of atypically high uplift payments.[66]

This coming winter, system operators may similarly pre-position resources in advance of expected cold weather. This could reduce reliability risks but also increase uplift payments in RTOs/ISOs.

For example, for PJM see PJM, Data Miner 2: Daily Uplift Charges by Zone (last accessed Oct. 6, 2025), https://dataminer2.pjm.com/feed/uplift_charges_by_zone; for NYISO see Open Access Same-Time Information System: Pricing Data (last accessed Oct. 6, 2025), https://mis.nyiso.com/public/; for MISO see MISO, Market Reports (last accessed Oct. 6, 2025) https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/; and for SPP, see SPP, Make Whole Payment Report (last accessed Oct. 6, 2025), https://portal.spp.org/pages/make-whole-payment-report.

[63] Like daily uplift payments, daily wholesale electricity costs based on RTO/ISO LMPs are also higher in the winter on average, compared to the rest-of-the-year.

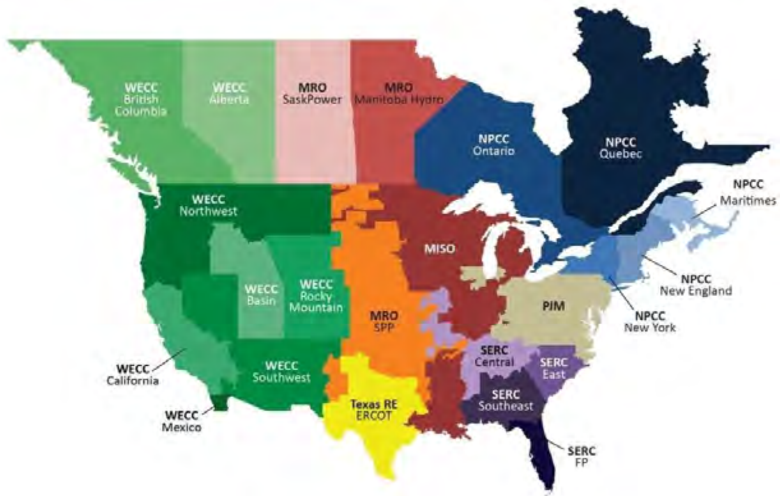
[64] Monitoring Analytics (PJM Independent Market Monitor), *2025 Quarterly State of the Market Report for PJM: January through June* at 284, 302-304 (Aug. 14, 2025), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025q2-som-pjm-sec4.pdf.

[65] PJM Operating Committee, *Cold Weather Operations: January 18–23, 2025* at 3 (Feb. 6, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250319/20250319-item-08---1-january-2025-cold-weather-update---presentation.pdf.

[66] PJM Members Committee, *Markets Report* at 27 (Feb. 18, 2025) (showing uplift as a percent of energy costs equal to almost 8% in January 2025 and below 2% for all preceding months), http://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250218-web/item-05a---1---market-operations-report.pdf.

Slide 20

Regional Highlights and Probabilistic Assessment



Source: NERC

NERC Regional Probabilistic Assessments

In this section, staff relies on NERC's probabilistic risk analyses[67] to assess resource adequacy. Regions can face energy shortfalls despite having planned reserve margins that exceed the reference margin levels.[68]

NERC's analysis shows that all assessment areas, as shown in **Slide 20**, anticipate adequate supplies and reserve margins under normal conditions, but ERCOT, NPCC-NE, SERC-East, SERC-Central, WECC-Basin, and WECC-NW may face a higher likelihood of tight supply and reliability issues during extreme conditions.[69] For all assessment areas, above-normal

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[67] A probabilistic risk analysis assesses the potential variations in resources and load that can occur under changing conditions or during certain scenarios and incorporates operator actions that could help to mitigate any shortfalls in operating reserves.

[68] NERC, *2025-2026 Winter Reliability Assessment* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[69] All Regional Entities and assessment areas provide a probability-based resource adequacy risk assessment for the winter season. NPCC-US consists of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, and New York; PJM consists of all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the

winter peak load and resource outages could result in the need to employ operational mitigations. In the event of challenging operating conditions, system operators take actions known as operational mitigations to address potential supply shortages, such as calling on demand response, canceling or postponing non-critical generation or transmission maintenance, and calling on voluntary conservation measures. If system conditions deteriorate sufficiently, Reliability Coordinators may declare an Energy Emergency Alert, allowing system operators to call on a variety of additional resources that are only available during scarcity conditions such as activating emergency demand response measures and increasing generation imports from neighboring regions.

Additionally, NERC assessment areas coordinate extensively ahead of anticipated extreme weather to try to prevent supply shortages. For example, ERCOT performs day-ahead and near-term studies to evaluate generation capacity at high risk due to extreme weather conditions to assess potential load shed scenarios. As part of ERCOT's protocols with SPP and MISO, ERCOT coordinates with the two RTO neighbors if look-ahead study results indicate that emergency conditions may arise.[70] NPCC-NE continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies.[71] Both SERC-Central and

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District of Columbia; SERC encompasses all or parts of North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Missouri, Kentucky, Florida, Arkansas, Illinois, Iowa, Louisiana, Oklahoma, Virginia, and Texas; MISO encompasses all or parts of 15 U.S. states including Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, and the Canadian province of Manitoba; SPP encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming; ERCOT is located entirely in the state of Texas; and WECC's footprint extends from Canada to Mexico and includes the provinces of Alberta and British Columbia; the northern portion of Baja California, Mexico; Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming; and portions of Montana, Nebraska, South Dakota and Texas. *See* NERC, *Long Term Reliability Assessment* (December 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[70] ERCOT, ERCOT-SPP Coordination Plan (Accessed Oct. 7, 2025), https://www.ercot.com/files/docs/2020/05/29/ERCOT-SPP-Coordination-Plan.pdf; ERCOT, ERCOT-MISO Coordination Plan (Accessed Oct. 7, 2025), https://www.ercot.com/files/docs/2019/03/27/ERCOT-MISO_Coordination_Plan.pdf.

[71] *NERC, 2025-2026 Winter Reliability Assessment* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

SERC-East report that fuel supplies and transportation remain stable, supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal and oil inventories are projected to remain adequate to meet winter demand.[72] WECC operators monitor grid market conditions in real time, with forecasts extending from the next day to seven days ahead for prescheduled trading.[73]

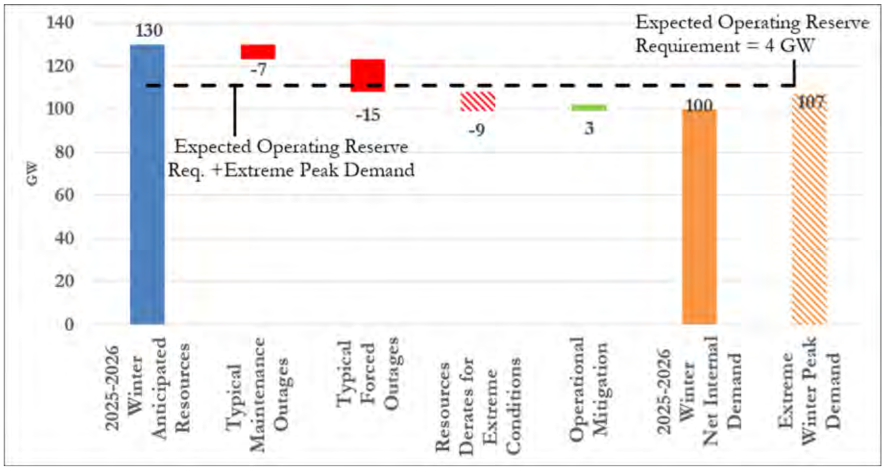
[72] *Id.*

[73] *Id.*

Slide 21

Example Seasonal Risk Assessment of a Region

Probabilistic Assessments



Source: NERC

Regional Highlights

NERC conducts probabilistic assessments of each assessment area that evaluates the risk of resource adequacy shortfalls for the winter. This winter risk period scenario compares chosen extreme scenarios determined by the NERC assessment areas. In this section, FERC staff highlights the following assessment areas: ERCOT, NPCC-NE, WECC-Basin, and WECC-NW. However, NERC's *2025-2026 Winter Reliability Assessment* also highlighted SERC-East and SERC Central.

NERC's *2025-2026 Winter Reliability Assessment* uses "waterfall" charts to provide a helpful visual of its probabilistic assessments for each region. The chart in **Slide 21** is an example seasonal risk assessment for a hypothetical region. The left blue column on the chart shows anticipated resources and the two orange columns on the right show the normal peak (50/50) and the extreme winter peak (90/10) demand scenarios.[74] The middle red bars show the factors that can reduce resource availability, including maintenance outages and forced outages, not already accounted for in anticipated resources. The middle green bar depicts potential additions in resource availability from operational mitigation actions, if any, that are available during scarcity conditions but have not been accounted for in the reserve margins.

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[74] A 50/50 peak load forecast is based on a 50% chance that the actual system peak load will exceed the forecasted value. A 90/10 peak load forecast is based on a 10% chance that the actual system peak load will exceed the forecasted value.

The dotted, horizontal line represents the expected operating reserve requirement plus the extreme peak demand, or the amount of power that a region would need to produce to avoid a shortfall.

The seasonal risk assessment scenarios are determined by the assessment areas to provide insight into unanticipated events during normal and/or extreme winter conditions. However, they do not account for all the unique energy adequacy risks associated with a specific area. The scenarios generally assess the greatest risk hour(s) for Expected Unserved Energy, along with the varying demand and available resource profiles. The methods, scenarios considered, and assumptions differ by assessment area and may not be comparable.

ERCOT. Winter peak demand in ERCOT's Texas footprint typically occurs before sunrise and after sunset when solar generation is unavailable.[75] ERCOT anticipates having sufficient operating reserves during the winter peak load hour (the hour ending at 8:00 a.m.) under expected normal system conditions. However, under extreme scenarios, the region faces increased risk of reserve shortages during both the peak-load hour and high net load hours. During these hours, the system relies heavily on wind generation and dispatchable resources.

Generally, risk in ERCOT continues to rise primarily due to factors such as robust load growth, slower evening load declines—which are largely attributed to continuous data center operations—and limited additions of new dispatchable capacity to meet elevated morning and evening net loads.[76] This risk is heightened by potential forced outages of thermal resources and reduced output from intermittent resources. The load growth in West Texas combined with scenarios for "no solar" and low wind conditions can cause transmission lines into this area to become heavily loaded. As one way to address this risk, ERCOT improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low solar irradiance.[77] The rapid increase in installed battery storage in ERCOT will also help address this risk. However, maintaining an adequate state of charge during prolonged high-load events, such as a widespread, multi-day event like Winter Storm Uri, remains a significant challenge.[78]

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[75] NERC, *2025-2026 Winter Reliability Assessment* at 31 (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[76] NERC, *2025-2026 Winter Reliability Assessment* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[77] *Id.*

[78] *Id. at 6*.

NPCC-NE. Under normal winter conditions, NPCC-NE has adequate resources to meet demand. However, a persistent concern in the region is whether sufficient energy will be available during an extended cold spell given the current resource mix, fuel delivery infrastructure, and expected fuel arrangements. Without significant efforts to replenish stored fuels such as fuel oil and LNG, energy adequacy could be challenged.[79]

In NPCC-NE, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods timely replenishment is critical to minimizing the potential for energy shortfalls. ISO-NE's 21-day energy forecast is intended to identify these types of scenarios. To support situational awareness and fuel procurement decisions, ISO-NE publishes a rolling 21-day energy assessment at least weekly with more frequent updates as needed.[80] This assessment provides early indications of potential fuel scarcity conditions for market participants.[81] ISO-NE has also expanded an existing winter readiness survey of generators to include more detailed questions, capturing additional data on potential temperature-related limitations.[82] ISO-NE will also continue to use its Probabilistic Energy Adequacy Tool to assess energy shortfall risks ahead of the 2025–2026 winter season.[83]

NPCC-NE shows little change to the anticipated reserve margin for this winter from the previous year, and a lower peak demand forecast and additional resources from demand

[79] *Id at 22.*

[80] ISO-NE, 21-Day Energy Assessment Forecast and Report (accessed Sept. 23, 2025), https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results.

[81] *Id.*

[82] ISO-NE, OP-21, Operational Surveys, Energy Forecasting & Reporting, and Actions During an Energy Emergency (Accessed Oct. 7, 2025), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf.

[83] Probabilistic Energy Adequacy Tool is a tool that ISO-NE use for risk analysis under extreme weather events. It is essential for evaluating the region's risk of energy shortfall — the electricity supply falling below consumer demand — giving the region's stakeholders advance warning and the opportunity to take steps to avert it; ISO New England, Update on Energy Adequacy Tool, Energy Shortfall Threshold, and Perspectives on Retail Demand Response, (May 21, 2024), https://www.iso-ne.com/static-assets/documents/100011/necpuc_sgeorge_may_2024_final.pdf; ISO New England, ISO Newswire: ISO-NE's study of energy shortfall risks produces innovative tool for assessing energy adequacy (Dec. 11, 2023), https://isonewswire.com/2023/12/11/iso-nes-study-of-energy-shortfall-risks-produces-innovative-tool-for-assessing-energy-adequacy/.

response and firm imports should offset recent generator retirements.[84] NPCC-NE imports power from Canada and neighboring RTOs/ISOs and periodically assesses its reliance on power transfers from neighboring Reliability Coordinator areas through market mechanisms and reliability studies. External resources may participate in the Forward Capacity Market, securing Capacity Supply Obligations to supply energy to New England when needed, integrating them into the region's capacity mix. An annual tie benefits study conducted by ISO-NE estimates reliable import capacity during stressed system conditions.[85]

WECC. WECC warns of potential reserve margin shortfalls in the WECC-Basin and WECC-NW assessment areas during the 2025–2026 winter season during the extreme condition scenario.

WECC-Basin. WECC-Basin encompasses all of Utah, the western part of Wyoming, and the southern and eastern part of Idaho. Under an extreme combination of derates and outages, WECC-Basin could be short one GW of internal supply and imports needed to serve load, and it expects an increased reliance on transfers. Net internal demand is expected to increase 1% since last winter, with total internal demand up 1.8%. This is offset by a doubling of controllable and dispatchable demand response. However, Tier 1 resources, which are capacity that is under construction or that has received approved planning requirements, have declined and do not appear to be offset by increases in existing-certain generation resource capacity.[86] Meanwhile, nameplate wind has increased by almost 18% and solar by almost 30%, and hydro is also up over 7% in total installed capacity since last winter, but derates need to

[84] NERC, *2025-2026 Winter Reliability Assessment* at 5 (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[85] The study analysis accounts for expected emergency assistance, system reliability practices and the Total Transfer Capability of external interfaces. *See* ISO-NE*, Benefits Values for Reconfiguration Auctions to be Conducted in 2025,* https://www.iso-ne.com/static-assets/documents/100015/a03_review_of_2025_2026_ara_3_tie_benefits_study_results.pdf ; ISO New England, Tie Benefits Methodology: Evaluation Review of Probabilistic Analysis, Tie Benefits Methodologies of ISO-NE and Other ISO/RTOs, and Tie Benefits Evaluation Scope of Work (Oct. 19, 2023), http://www.iso-ne.com/static-assets/documents/100004/a05_tie_benefits_methodology_evaluation.pdf.

[86] Existing-certain includes 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 winter season: (1) unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; (2) unit must be classified as a designated network resource; and/or, (3) where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.

be factored into the performance calculations. Overall, WECC-Basin expects to be reliant on imports to maintain resource adequacy.[87]

WECC-NW. WECC-NW encompasses all of Montana, Washington, and Oregon, and the northern parts of both Idaho and California. WECC-NW has historically been a mixed-season peaking region and shows operating reserve margins expected to be met before needing imports for all winter scenarios. This winter, projected total and net internal demand are up 9.3%, with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing. Large coal unit retirements and conventional hydro unit retirements contribute to the reduction in existing certain capacity by 10.5%; however, planned Tier 1 resources (capacity that is under construction or has received approved planning requirements) have soared over 580%, from 463 MW to over 3 GW. An increase in nameplate capacity for both wind and solar in WECC-NW has also led to a moderate increase in solar availability during the peak hour.

To assess long-term vulnerabilities for all of WECC, WECC conducted two studies evaluating the impact of extreme cold weather events on electric system reliability 10 and 20 years into the future.[88] Both studies highlight the risks[89] associated with heavy reliance on natural gas during severe winter conditions. According to WECC, currently there are no reported or planned pipeline disruptions or outages that would directly threaten natural gas delivery in winter 2025-2026. But lessons from Winter Storm Elliott underscore how freeze-offs, scheduling mismatches, and pipeline constraints have previously contributed to generation

[87] NERC, *2025-2026 Winter Reliability Assessment* at 33 (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[88] WECC, *Year 10 Extreme Cold Weather Event* (Nov. 2023), https://www.wecc.org/sites/default/files/documents/meeting/2024/Year-10%20Extreme%20Cold%20Weather%20Event%20Report%202023.pdf; WECC, *Year 20 Extreme Cold Weather Event*, (April 2024), https://www.wecc.org/sites/default/files/documents/meeting/2024/Year%2020%20Cold%20Weather%20Event%20Study.pdf.

[89] The studies shows that the western grid depends heavily on natural gas-fired generation to meet demand during extreme cold events. According to the studies, during cold snaps natural gas supply and pressure can drop due to heating demand and infrastructure freezing. Also, the reports note that if gas supply is constrained or derated (by 15–35%), large amounts of unserved energy could occur.

shortfalls and power outages. Since then, improvements such as revised gas pipeline logic[90] and expedited emergency protocols have strengthened system resilience.[91]

The Western Interconnection remains a focal point for proposed pipeline expansions aimed at easing regional supply constraints.[92] While these projects could eventually stabilize fuel prices and support growing demand, most remain in early development stages and will not be in place for winter 2025-2026.[93]

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[90] Gas pipeline logic refers to the system of rules, controls and decision-making processes that govern the operation, monitoring, and optimization of natural gas transmission through pipelines.

[91] WECC Assurance Program provides WECC and its stakeholders with tools to help manage specific risks related to extreme weather and recommendations for improvements to policies, processes and procedures for reviewing system performance during extreme weather events; WECC, WECC Assurance Program explainer (May 15, 2025); https://www.wecc.org/sites/default/files/documents/initiative/2025/Assurance%20Program%205.15.2025.pdf.

[92] S&P Capital IQ Pro, Natural Gas Development Projects (Accessed Oct. 2, 2025), https://www.capitaliq.spglobal.com/web/client?auth=inherit#industry/GasProjects.

[93] These projects include the Desert Southwest Pipeline Expansion (Transwestern Pipeline Company, owned by Energy Transfer): This project involves constructing 516 miles of 42-inch pipeline and nine compressor stations to transport up to 1.5 Bcfd of natural gas from the Permian Basin (Texas/New Mexico) to markets in Arizona and the Southwest. It was announced in August 2025, with a binding open season launched in September 2025. The construction is pending regulatory approvals and final investment decisions. Energy Transfer LP, *Energy Transfer Announces Natural Gas Pipeline Project to Serve Growing Southwestern U.S. Markets*, press release, (August 6, 2025), https://ir.energytransfer.com/news-releases/news-release-details/energy-transfer-announces-natural-gas-pipeline-project-serve; Also included is the Helena-to-Three Forks Pipeline Project (NorthWestern Energy), a proposed natural gas pipeline in Montana, spanning from Helena south to the Three Forks area. It aims to enhance service reliability, add system redundancy by linking existing infrastructure, and support regional energy needs. Construction is expected to begin in 2027. NorthWestern Energy Group, Inc., Helena to Three Forks Natural Gas Transmission Pipeline Project 2024, (Accessed Oct. 7, 2025), https://northwesternenergy.com/about-us/our-projects/helena-to-three-forks-pipeline-project#.

Slide 22

2025-2026 Winter Energy Market and Electric Reliability Assessment

market.assessments@ferc.gov

This concludes the 2025-2026 Winter Energy Market and Electric Reliability Assessment. For questions regarding this report please contact market.assessments@ferc.gov.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 145

NERC Email

Subject: Announcement | NERC 2025-2026 Winter Reliability Assessment | Rising Demand, Evolving Resources Continue to Challenge Winter Grid Reliability
Date: Tuesday, November 18, 2025 at 2:02:44 PM Eastern Standard Time
From: NERC Communications Announcements (Do Not Reply) (SM)
To: Rachel Sherrard
Attachments: image007.jpg, image008.png, image009.png, image010.png, image002.png

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Announcement

Rising Demand, Evolving Resources Continue to Challenge Winter Grid Reliability

Full Announcement | 2025-2026 Winter Reliability Assessment | Infographic | Video

WASHINGTON, D.C.— NERC's *2025–2026 Winter Reliability Assessment* (WRA) finds that much of North America is again at an elevated risk of having insufficient energy supplies to meet demand in extreme operating conditions. Although resources are adequate for normal winter peak demand, any prolonged, wide-area cold snaps will be challenging. This is largely due to rising electricity demand, which has grown by 20 GW since last winter, significantly outpacing winter on-peak capacity. This, coupled with the changing resource mix, is affecting the winter outlook.

Undertaken annually in coordination with the Regional Entities, NERC's WRA examines multiple factors that collectively provide deep and unique insights into reliability risk. These factors include resource adequacy, encompassing reserve margins and scenarios to identify operational risk; fuel assurance; and preparations to mitigate reliability concerns.

For more information or assistance, please contact NERC Communications

www.nerc.com

RELIABILITY | RESILIENCE | SECURITY

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 146

August 2025 Rehearing Order

UNITED STATES OF AMERICA
Department of Energy
Washington, DC 20585

Midcontinent Independent System Operator, Inc. and Consumers Energy Company Regarding the J.H. Campbell Generation Facility

Order No. 202-25-7B

ORDER ADDRESSING ARGUMENTS RAISED ON REHEARING

(Issued January 21, 2026)

1. On August 20, 2025, pursuant to section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] the Secretary of Energy (Secretary) issued an order determining 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 electricity, and other causes."[3] In the Emergency Order, the Secretary determined that "continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c)."[4]

2. On September 8, 2025, a request for rehearing was filed by Public Interest Organizations (PIOs);[5] on September 11, 2025, a rehearing request was filed by Michigan Attorney General Dana Nessel (Michigan AG); and on September 19, 2025, a rehearing request was filed by the States of Minnesota and Illinois (Minnesota and Illinois). On September 19, 2025, Consumers Energy Company filed a limited request for clarification.

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] Department of Energy Order No. 202-25-7 (Aug. 20, 2025) (Emergency Order).

[4] *Id.* at 7.

[5] Sierra Club, Natural Resources Defense Council, Michigan Environmental Council, Environmental Defense Fund, Environmental Law and Policy Center, Vote Solar, Union of Concerned Scientists, the Ecology Center, and Urban Core Collective refer to themselves collectively as Public Interest Organizations.

3. On October 23, 2025, the Department of Energy (DOE) issued a notice of denial of rehearing by operation of law and providing for further consideration (DOE Notice).[6] However, as provided in sections 202(c) and 313(a) of the FPA,[7] DOE is modifying the discussion in the Emergency Order and continues to reach the same result in this Order, as discussed below.[8]

I. Background

4. In the Emergency Order, the Secretary determined 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 electricity, and other causes," and that "[i]ssuance of this Order will meet the emergency and serve the public interest."[9] The Secretary therefore directed the Midcontinent Independent System Operator, Inc. (MISO), and Consumers Energy, the Campbell Plant's owner, to "take all measures necessary to ensure that the Campbell Plant is available to operate."[10]

5. The Emergency Order provided substantial support for the Secretary's emergency determination. In the Emergency Order, the Secretary reiterated that the North American Electric Reliability Corporation (NERC) indicated in its 2025 Summer Reliability Assessment 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."[11] The Secretary observed that multiple generation facilities in Michigan have

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[6] Department of Energy Order No. 202-25-7A (Oct. 24, 2025).

[7] 16 U.S.C. § 824a(c); 16 U.S.C. § 825*l*(a). In the context of FPA section 202(c) orders, the DOE interprets FPA section 313's references to "the Commission" to mean DOE.

[8] *See Allegheny Def. Project v. FERC*, 964 F.3d 1, 16-17 (D.C. Cir. 2020). The Department is not changing the outcome of the Emergency Order. *See Smith Lake Improvement & Stakeholders Ass'n v. FERC*, 809 F.3d 55, 56-57 (D.C. Cir. 2015).

[9] Emergency Order at 1.

[10] Emergency Order at 8, Ordering Paragraph A.

[11] *Id.* at 1 (quoting *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment). The Emergency Order stated that NERC anticipates "elevated risk of operating reserve shortfalls" notwithstanding Consumers Energy's acquisition of a 1,200 MW natural gas power plant in Covert, Michigan. *Id.* at 2.

retired in recent years, specifically identifying the closures of two nuclear plants—Big Rock Point and Palisades.[12] The Secretary explained that the retirement of the Campbell Plant would further decrease the amount of available dispatchable generation in MISO's service territory, noting that a combined 1,575 MW of natural gas and coal-fired generation had retired since the summer of 2024.[13] The Secretary further noted that MISO's 2025/2026 Planning Resource Auction results indicated that, for the North/Central sub-regions, new capacity additions were insufficient to offset the negative impacts of accreditation, suspensions/retirements and external resources and that, 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.[14]

6. The Secretary explained that (as of August 21, 2025, the date when the Emergency Order was issued) the summer season had not yet concluded, and that the Campbell Plant continues to play a critical role in maintaining generation reliability in MISO.[15] The Secretary noted the Campbell Plant's substantial electricity generation during a summer heat wave that hit MISO, when the Campbell Plant produced approximately 664,000 MWh in June 2025 and operated at 61% capacity.[16] The Secretary further observed that, on over 40 of the 69 days between June 11 and August 18, MISO had to issue numerous alerts to manage grid reliability in response to extreme weather, high demand, forced generation outages, and transmission limitations.[17] The Secretary also noted a July 17, 2025 Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA), which projected a significantly increased likelihood of above-normal

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[12] *Id.*

[13] *Id.*

[14] *Id.* (summarizing *Planning Resource Auction—Results for Planning Year 2025–2026*, Midcontinent Independent System Operator, Inc., at 13 (Apr. 2025)). After the Emergency Order was issued, on May 29, 2025, MISO posted a corrected version of the presentation, which is available here: https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[15] *Id.*

[16] *Id.* at 3 (citing *Custom Data Download, EPA CAMPD (Clean Air Markets Program Data)*, https://campd.epa.gov/data/custom-data-download (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June." The data can then be filtered to only include the Campbell Plant.).

[17] *Id.*

temperatures for the Midwest region, with estimates rising to a 40-50% chance for much of the Midwest region, including Michigan.[18]

7. The Secretary also explained that MISO's resource adequacy problems are not limited to the summer season.[19] The Secretary observed that, in 2022, in its own filing to revise its resource adequacy construct, MISO requested Federal Energy Regulatory Commission (FERC) approval to establish capacity requirements for all four seasons rather than annually based on peak summer demand.[20] As the Secretary noted, MISO justified this request because "[r]eliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[21] The Secretary also noted that MISO's December 2023 "Attributes Roadmap" provided an in-depth look at the evolving challenges of operating a reliable bulk electric system amid a rapidly transforming energy landscape.[22] The Roadmap highlighted that, while the 2023/24 Planning Year still viewed the greatest risk of loss of load in the summer, projections indicated that by the summer of 2027, the risk will be equally high in both the summer and fall seasons.[23] It is also projected that, although the risk of loss of load in the winter and spring will not reach the same level as in summer or fall, it is nonetheless expected to increase over time.[24] The Secretary observed that MISO reaffirmed its findings in a 2024 report, *MISO's Response to the Reliability Imperative*, underscoring that MISO has resource reliability concerns outside of the summer season.[25]

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[18] *Id.* (citing *Seasonal Outlook*, NOAA Climate Prediction Ctr. (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1) (search terms in search box "2025" and "07").

[19] *Id.*

[20] *Id.* (citing *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021)).

[21] *Id.* at 3-4 (citing MISO Transmittal Letter, at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021)).

[22] *Id.* at 4.

[23] *Id.* (citing MISO, *Attributes Roadmap*, at 11 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf).

[24] *Id.*

[25] *Id.* (citing MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final50

8. The Secretary further explained that evidence indicates that "there is also a potential longer term resource adequacy emergency in MISO."[26] The Secretary stated that the results of MISO's Public Resource Auction (PRA) for the 2025-26 Planning Year indicated that "'new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources' in the northern and central zones, which include Michigan."[27] The Secretary further referenced the 2025 Organization of MISO States (OMS)-MISO Survey Results, which projected that although there could be a capacity surplus for the summer of 2026, at least 3.1 GW of additional generation capacity will be needed beyond what is currently committed to meet MISO's projected planning reserve margin requirements.[28] For each of the following four summers, the survey projected insufficient capacity to meet peak demand, with deficits increasing from 1.4 GW in 2027 to 8.2 GW by 2030.[29] The Secretary discussed that the primary reasons for these projected deficits are the continued retirement of existing generation capacity and accelerating electricity demand.[30] The Secretary acknowledged that MISO has been taking steps to address these projected deficits, but further assessed MISO's efforts as "unlikely to result in the addition of any new generation capacity in the next few years."[31]

9. As discussed further below, the Emergency Order also observed that, earlier this year, the President issued executive orders which underscored the severity of the current energy emergency in the United States.[32] In this respect, the Secretary noted DOE's July

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4018.pdf).

[26] *Id.*

[27] *Id.* (quoting MISO, *Planning Resource Auction – Results for Planning Year 2025-26*, at 13 (corrected May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf).

[28] *Id.* at 4-5 (citing OMS and MISO, *2025 OMS-MISO Survey Results*, at 2 (updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf).

[29] *Id.* at 5 (citing OMS and MISO, *2025 OMS-MISO Survey Results*, at 7).

[30] *Id.*

[31] *Id.*

[32] *Id.* at 6 (citing Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/; Exec. Order No. 14156, 90 Fed. Reg. 8433

2025 Resource Adequacy Report, which was prepared specifically in response to the President's Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[33] DOE's Resource Adequacy Report detailed that the United States' power grid will be "unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence [ ] innovation."[34]

10. Finally, the Secretary referenced recent congressional testimony from Jennifer Curran, Senior Vice President, Planning and Operations, MISO.[35] In her written testimony, Ms. Curran explained that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[36]

11. In view of this evidence, the Secretary therefore determined that continued operation of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). The Secretary's expert determination was based on the fact that increasing electricity demand, coupled with accelerated retirements of generation facilities continuing in the near term as well as subsequent years, would result in a risk to public health and safety caused by the potential loss of power to homes and businesses in areas that may be affected by curtailments or outages. The Emergency Order was limited in duration to align with the emergency circumstances. In

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(Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/).

[33] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), at Section 3(b) (mandating the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by FERC).

[34] Emergency Order at 6 (quoting *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf).

[35] *Id.* at 6-7 (citing Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator) (Curran Test.), at 5, https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-media-document/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf).

[36] *Id.* at 6-7 (quoting Curran Test. at 5).

recognition of potential conflict with environmental standards and requirements and consistent with FPA section 202(c), the Secretary authorized only the necessary additional generation on specified conditions.[37]

II. Discussion

1. The Secretary's Authority to Determine the Existence of an "Emergency"

12. Michigan AG, PIOs, and Minnesota and Illinois each raise similar arguments that the Emergency Order failed to meet the legal definition of an "emergency" within the meaning of FPA section 202(c).[38] Michigan AG argues that, while section 202(c) "permits some measure of flexibility with respect to what type of events may cause the emergency, allowing for 'other causes' beyond those enumerated," it only authorizes action during extraordinary circumstances.[39] Michigan AG[40] and PIOs[41] cite to various dictionary definitions of "emergency" to assert the same point. PIOs[42] and Minnesota and Illinois[43] also each similarly assert that the Emergency Order is "novel" and contravenes DOE's historic use of section 202(c) to address natural disasters and specific capacity crises, or retirements "only when requested."[44]

13. Further, Michigan AG,[45] PIOs,[46] and Minnesota and Illinois[47] each rely on *Richmond Power and Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978), and *Otter Tail Power*

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[37] Emergency Order at 8.

[38] Michigan AG Pet. § IV.A.i; PIO Pet. § V.A.1; Minnesota and Illinois Pet. § V.B.

[39] Michigan AG Pet. at 34-35.

[40] *Id.* at 35.

[41] PIO Pet. at 46.

[42] *Id.* at 52.

[43] Minnesota and Illinois Pet. at 37-38.

[44] *Id.* at 38.

[45] Michigan AG Pet. at 36-37.

[46] PIO Pet. at 50-51.

[47] Minnesota and Illinois Pet. at 39-40.

Co. v. Federal Power Commission, 429 F.2d 232 (8th Cir. 1970), for the proposition that courts have interpreted section 202(c) narrowly to apply only to temporary emergencies requiring an imminent response.

DOE's Determination

14. The Secretary has statutory authority under FPA section 202(c) to determine that an emergency exists and exercise his judgment to address such an emergency. The statute's plain text grants the Secretary authority to respond to threats to the Nation's electric infrastructure. Specifically, the Secretary "*shall* have authority" to act "*whenever* the [Secretary] determines that an emergency exists."[48] Next, the statute sets forth three different categories of emergency where section 202(c) action is permissible. An emergency may exist "by reason of [1] a sudden increase in the demand for electric energy, or [2] 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 [3] other causes."[49]

15. Pursuant to section 202(c)(1), the Secretary has authority to determine the existence of a statutory emergency, "either upon [his] own motion or upon complaint, with or without notice, hearing, or report." Beyond providing categories of when an "emergency exists," the statute is silent on any additional requirements that must be satisfied. Here, as is evident from the face of the Emergency Order, and as is consistent with section 202(c)'s text and prior DOE practice,[50] the Secretary exercised his authority under section 202(c) and determined, in his statutory discretion and substantive expertise, 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 electricity, and other causes."[51]

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[48] 16 U.S.C. § 824a(c)(1) (emphases added).

[49] *Id.* (brackets added); *see also* H.R. Rep. No 113-86, at 2 (2013) (House Committee on Energy and Commerce Report on then-proposed amendment to section 202(c), which observed that "[r]eliability-related emergencies are not limited to bad weather, natural disasters, or terrorist attacks").

[50] *See, e.g.*, *Puget Sound Power & Light Co.*, 6 F.P.C. 320 (1947) (WL 1048) (in which the Federal Power Commission (FPC, the predecessor of DOE) used FPA section 202(c) to prevent an anticipated power shortage despite noting that the current power supply was adequate).

[51] *See* Emergency Order at 1.

16. The argument that the Secretary can act only when a shortage of electricity is "imminent" does not comport with the statutory authority conferred by section 202(c). The word imminent does not appear in the statute. The Secretary may act to address any "shortage of . . . facilities for the generation . . . of electric energy." Were the Secretary to be required to wait until a blackout was "imminent" before addressing a shortage of generation facilities, his ability to take meaningful action under section 202(c) to prevent the blackout would be gravely impaired. Section 202(c) must be interpreted in the context of the electric industry. It can take months, and even years, to remedy a shortage of facilities for the generation of electric energy once a shortage is identified. This fact is squarely recognized in DOE's implementing regulations for FPA section 202(c), in effect since 1981, which defines the term "emergency" to include "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities."[52] Furthermore, the definition of "emergency" contained in DOE's regulations at 10 C.F.R. § 205.371—which generally provide guidance to applicants seeking section 202(c) relief—does not supersede the statutory discretion section 202(c) affords to the Secretary to *sua sponte* "determine[] that an emergency exists." Accordingly, the Secretary's emergency determination is entirely consistent with the governing statutory requirements in section 202(c) and the DOE's regulations.

17. Michigan AG[53] and PIOs[54] each raise similar arguments that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities" do not constitute an emergency themselves without resulting in an unexpected, imminent inability to supply electric services. However, as discussed above, requiring the Secretary to act only when an electricity shortage is imminent does not comport with the statutory authority under section 202(c) to address a "shortage of . . . facilities for the generation . . . of electric energy." Accordingly, the Secretary's emergency determination is entirely consistent with the governing statutory requirements in FPA section 202(c) and DOE's regulations.

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[52] 10 C.F.R. § 205.371; *accord Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power*, 46 Fed. Reg. 39984-01 (Aug. 6, 1981).

[53] Michigan AG Pet. at 38.

[54] PIO Pet. at 50.

18. The dictionary definitions cited by Michigan AG[55] and PIOs[56] are not persuasive. Those dictionary definitions cannot limit the discretion Congress expressly delegated to the Secretary in section 202(c).

19. The arguments made by Michigan AG,[57] PIOs,[58] and Minnesota and Illinois[59] based on the *Otter Tail Power* and *Richmond Power and Light* decisions are likewise misguided. *Otter Tail Power* did not limit the Secretary's section 202(c) discretion or the meaning of "emergency" because the court held that section 202(c) *did not apply* to the case.[60] Instead, *Otter Tail Power* involved section 202(b) of the FPA and not an "emergency" within the meaning of section 202(c).[61] In *Richmond Power and Light*, the Court of Appeals for the D.C. Circuit merely held that the Federal Power Commission (FPC) did not abuse its discretion in *declining* to invoke its emergency powers under section 202(c).[62] The court determined that the FPC had discretion to choose a temporary, voluntary program rather than issue an order pursuant to section 202(c), as the circumstance, in the FPC's discretion, did not warrant the use of emergency authority.[63]

20. A more relevant decision is *Board of Trade of the City of Chicago v. Commodity Futures Trading Commission*.[64] In that case, the Court of Appeals for the Seventh Circuit recognized the broad power of the Commodity Futures Trading Commission (CFTC) to

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[55] Michigan AG Pet. at 35.

[56] PIO Pet. at 46.

[57] Michigan AG Pet. at 36-37.

[58] PIO Pet. 50-51.

[59] Minnesota and Illinois Pet. at 39-40.

[60] *See Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232, 234 (8th Cir. 1970) (Otter Tail Power).

[61] *Id.* (rejecting petitioner's contention that "any proceedings in the instant case must be dealt with in compliance with § 202(c)").

[62] *See Richmond Power and Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978) (*Richmond Power and Light*).

[63] *Id.* at 614-15.

[64] *Bd. of Trade of City of Chicago v. Commodity Futures Trading Comm'n*, 605 F.2d 1016, 1025 (7th Cir. 1979).

issue emergency actions under section 8a(9) of the Commodity Exchange Act (7 U.S.C. § 12a(9)).[65] Through section 8a(9), the CFTC issued an emergency order for the Board of Trade to suspend trading in certain wheat futures contracts, citing transportation and warehouse shortages and potential market manipulation.[66] In response, the Board of Trade sought an injunction against the order, arguing that no emergency existed.[67] The district court granted a preliminary injunction, and the CFTC appealed.[68] In its decision to vacate and remand the district court's preliminary injunction, the Seventh Circuit concluded that Congress intended to grant the CFTC discretion in making emergency determinations under the Commodity Exchange Act.[69] The court reasoned: "Congress recognized that regulation of the volatile futures markets could be accomplished effectively only through the use of an expert Commission, that situations could occur suddenly for which the traditional enforcement powers would be an inadequate response, and that therefore the Commission should have emergency powers, the exercise of which is committed to the expertise and discretion of the Commission."[70] In addition, "[t]he fact that the Commission is authorized by Congress to take emergency action is, in itself, a suggestion of Congressional intent to commit such actions to the Commission's discretion."[71] Given the similarities between FPA section 202(c) and section 8a(9) of the Commodity Exchange Act, the *Board of Trade* decision confirms the conclusion that Congress intended to grant the Secretary broad discretion to determine when his emergency powers should be applied to protect the public interest.[72]

21. Further, the assertions of PIOs and Minnesota and Illinois that the Emergency Order is "novel" and contravenes prior practice wherein section 202(c) was used to address natural disasters and specific capacity crises, or retirements "only when requested" has no merit.[73] On its face, section 202(c)(1) authorizes the Secretary to act "*either upon its own*

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[65] *Id.*

[66] *Id.* at 1018.

[67] *Id.* at 1019.

[68] *Id.* at 1019-20.

[69] *Id.* at 1023-25.

[70] *Id.* at 1025.

[71] *Id.* at 1023.

[72] *See id.* at 1023-25.

[73] *See* PIO Pet. at 52; Minnesota and Illinois Pet. at 37-38.

motion or upon complaint." As such, under the statute, it is irrelevant whether a utility requested that the Secretary take this action. Moreover, it is undisputed that section 202(c) has been used in the past to address generation retirements.[74]

22. In sum, the Secretary acted within his authority to determine the existence of an emergency, and the statutory meaning of "emergency" has been satisfied here. In its 90-year history, no court has questioned the Secretary's (or, prior to its dissolution in 1977, the FPC's)[75] judgment in this respect. This history is consistent with the breadth of the Secretary's authority expressly delegated in the statute.

2. The Secretary's Authority to Require the Campbell Plant to Continue to Operate

23. Michigan AG, PIOs, and Minnesota and Illinois argue that the Emergency Order impermissibly exceeds the Secretary's statutory authority under FPA section 202(c) in various respects.[76] For instance, Michigan AG and PIOs argue that the Emergency Order, in effect, impermissibly asserts the authority to further DOE's policy decisions by managing issues unrelated to addressing emergencies but rather concerning resource adequacy and electric generation facilities—issues which are reserved for the states and FERC, pursuant to other provisions in the FPA.[77] Michigan AG,[78] PIOs,[79] and Minnesota and Illinois[80] also cite to the definition of "emergency" in DOE's regulations at 10 C.F.R. § 205.371 and argue that the Emergency Order exceeded the scope of that definition.

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[74] *See, e.g.*, *PJM Interconnection, L.L.C.*, Order No. 202-17-2 (2017) (in which DOE authorized Dominion Energy Virginia to operate Yorktown Power Station Units 1 and 2 as needed for reliability purposes despite their planned deactivation).

[75] The FPC was dissolved in 1977, and the FPC's functions were split between FERC and the Department, with the Secretary retaining FPA section 202(c) power.

[76] Michigan AG Pet. § IV.B; PIO Pet. § IV.C; Minnesota and Illinois Pet. § V.E; OMS Pet. § B.

[77] *See* Michigan AG Pet. § IV.B.i (citing 16 U.S.C. § 824(b)(1) and 16 U.S.C. §§ 824d, 824e); PIO Pet. at 76-77 (citing 16 U.S.C. § 824(a)); *id*. at 78 (citing *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016)).

[78] Michigan AG Pet. at 37-38.

[79] PIO Pet. at 49-50.

[80] Minnesota and Illinois Pet. at 37.

24. Michigan AG and PIOs further contend that the Emergency Order impermissibly overrides FERC decisions requiring an operating resource to be a capacity resource.[81] Michigan AG and Minnesota and Illinois contend that the Emergency Order impermissibly intrudes on the states' authority to make decisions concerning generation facility retirements.[82] PIOs also refer to the FPA's statutory structure, contending that in enacting FPA section 215,[83] Congress established a "circumscribed" framework of federal action for addressing long-term reliability concerns in careful balance with the states, federal regulators, and other stakeholders.[84] PIOs assert that DOE's use of section 202(c) to address long-term reliability concerns (and not, as PIOs say, imminent threats) would effectively bypass the framework Congress provided under section 215.[85] Similarly, Minnesota and Illinois contend that in enacting FPA section 215, Congress established a different authority in connection with "long-term planning," and that "emergency orders are not the proper mechanism to engage in resource planning five years into the future."[86]

DOE's Determination

25. There is no dispute that the Secretary has the statutory authority under FPA section 202(c) to (1) determine that an emergency exists, and then (2) exercise his judgment to address that emergency. Rather, Michigan AG, PIOs, and Minnesota and Illinois claim that the Secretary exceeded that authority in certain respects. As explained below, Petitioners' claims have no merit.

26. FPA section 201(b)(1) of the FPA specifically reserves authority over "facilities used for the generation of electric energy" for the states "*except as specifically provided* in this subchapter."[87] Section 202(c) constitutes one such exception. It grants the Secretary the "authority, either upon [the Secretary's] own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public

[81] Michigan AG Pet. at 54-55; PIO Pet. at 79-80.

[82] Michigan AG Pet. at 53-54; Minnesota and Illinois Pet. at 44-46.

[83] 16 U.S.C. § 824o.

[84] PIO Pet. at 48-49.

[85] *Id.*

[86] Minnesota and Illinois Pet. at 38.

[87] 16 U.S.C. § 824(b)(1) (emphasis added).

interest." Congress thus purposely provided discretion in section 202(c) to require changes to the operations of electric generating facilities to meet the emergency.

27. Michigan AG and PIOs' attempt to avoid this clear grant of authority by arguing that the Emergency Order addresses issues unrelated to emergencies and instead concerns the issue of resource adequacy and long-term reliability.**[88]** But placing a different label on the Secretary's action cannot change the fact that actions taken in the Emergency Order fall squarely within the authority granted by section 202(c). By its terms, section 202(c) may be invoked to address a potential "shortage of electric energy or of facilities for the generation or transmission of electric energy," which is exactly the situation that led to the issuance of the Emergency Order. The Secretary is also authorized to "require by order . . . such generation . . . of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest," which is exactly the action the Emergency Order requires. Moreover, DOE's regulations specifically provide 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 as contemplated in these regulations." As such, this provision reinforces that section 202(c) may be used to address long-term structural problems, not simply imminent and unexpected events—which is precisely what the Secretary did with the Emergency Order. DOE regulations thus implement the broad grant of discretion section 202(c) affords to the Secretary to "determine[] that an emergency exists."**[89]**

28. Contrary to Petitioners' assertions,**[90]** the Secretary is not taking action to address matters otherwise delegated to the states or FERC, nor is he exceeding his statutory authority under section 202(c). Specifically, due to inadequate planning and delays in the construction of new generation assets,**[91]** the Secretary took action to address the emergency in MISO. As described in the Emergency Order, MISO's resource crisis arises, among other reasons, from the mismatch between resource retirements, such as the Campbell Plant, and heightened demand, including due to the sudden development of large data centers in MISO's service region.**[92]** This "growing reliability risk" from "the

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88 *See* Michigan AG Pet. § IV.B.i (citing 16 U.S.C. § 824(b)(1) and 16 U.S.C. §§ 824d, 824e); PIO Pet. at 44 (citing 16 U.S.C. § 824(a)); *id*. at 45 (citing *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016)).

89 16 U.S.C. § 824a(c)(1).

90 *See, e.g.*, Michigan AG Pet. § IV.B; PIO Pet. § V.A.2.

91 *See* Emergency Order at 5.

92 *Id.*; *see also id.* at 7 (noting increases in demand in MISO due resurgence in manufacturing activity and "unexpected demand for energy-hungry data centers" (quoting rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[93] If not for the Emergency Order, the Campbell Plant would have been retired on May 31, 2025, further decreasing the available dispatchable generation within MISO and deepening the reliability crisis. The emergency action taken thus best preserves the reliability of the grid until new generation resources can be added and is entirely consistent with the governing statutory requirements in section 202(c) and its implementing regulations.

29. Nor is there any requirement under section 202(c), as Minnesota and Illinois suggest,[94] that the Secretary consult with the potentially impacted states prior to issuing a section 202(c) order. Section 103 of the DOE Organization Act requires consultation with states "where practicable."[95] In an emergency situation, it is often not practicable to consult with the states and relevant state agencies prior to taking emergency action. This point is further supported by the plain language of section 202(c), which specifically authorizes DOE to issue an emergency order "with or *without notice*."[96]

30. Finally, Michigan AG and PIOs' argument that the Emergency Order impermissibly overrides FERC decisions requiring an operating resource to be a capacity resource[97] is incorrect. The Emergency Order states that, "[b]ecause this Order is predicated on the *shortage* of facilities for the generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource."[98] Capacity markets are market constructs to ensure that adequate generation exists to serve future electricity demand; the higher capacity market prices attract new firm generation. DOE's recitation that the Campbell Plant would not be a capacity resource was a statement of DOE's intent not to interfere with FERC and the regulated capacity market.[99] As such,

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Curran Test. at 6)).

[93] Curran Test. at 7; *see also* Emergency Order at 5 (describing delays in constructing new capacity, including due to supply chain constraints for critical grid components).

[94] *See, e.g.*, Minnesota and Illinois Pet. at 45-46.

[95] 42 U.S.C. § 7113.

[96] 16 U.S.C. § 824a(c)(1) (emphasis added).

[97] Michigan AG Pet. at 54-55; PIO Pet. at 79-80.

[98] Emergency Order at 8, Ordering Paragraph G (emphasis added).

[99] Under the terms of the MISO tariff, zonal resource credits may only be sold from designated "capacity resources." *See* MISO, *Resource Adequacy Business Practices*

the Emergency Order ensures that the Campbell Plant does not participate in the relevant capacity market, which could artificially lower the price signals intended to attract needed new firm generation.

3. The Factual Basis to Support the Secretary's Emergency Determination

31. Michigan AG, PIOs, and Minnesota and Illinois also raise similar objections that there is no factual basis to support the Emergency Order, and that the Secretary is required to submit "substantial evidence" in support of his emergency determination, as summarized below.[100] Michigan AG, PIOs, and Minnesota and Illinois dismiss the Emergency Order's references to MISO alerts issued in June and July 2025 to manage grid reliability and the fact that MISO called upon the Campbell Plant to operate in June 2025.[101] Rather, Minnesota and Illinois describe such MISO alerts as "common" and not indicative of emergency.[102]

32. Michigan AG, PIOs, and Minnesota and Illinois further assert that the factual evidence cited in the Emergency Order does not demonstrate the existence of an emergency.[103] For example, Michigan AG contends that MISO's year-round capacity auctions do not demonstrate a capacity shortfall,[104] and that the MISO "Attributes Roadmap" likewise does not present evidence of an emergency.[105] According to Petitioners, the projected shortfalls described in MISO's 2025/2026 Planning Resource Auction results, the 2025 OMS-MISO survey, the DOE's July 2025 Resource Adequacy Report, and the 2025 NERC Summer Reliability Assessment, also do not demonstrate an

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Manual, BPM-011-r31, section 2.2. Under the Emergency Order, the Campbell Plant shall not be considered a capacity resource and thus cannot sell other capacity market products such as replacement capacity. *See* Consumers Energy, *Limited Request for Clarification of Consumers Energy Company* (September 19, 2025).

[100] Michigan AG Pet. §§ IV.A(ii), IV.C(i)-(ii); PIO Pet. § V.A.2-3; Minnesota and Illinois Pet. § V.A.

[101] Michigan AG Pet. at 40-44; PIO Pet. at 63-64; Minnesota and Illinois Pet. at 27-31.

[102] Minnesota and Illinois Pet. at 27.

[103] Michigan AG Pet. at 44-45; PIO Pet. at 62-63; Minnesota and Illinois Pet. at 26.

[104] Michigan AG Pet. at 44-45.

[105] Michigan AG Pet. at 45-46; *see also* Minnesota and Illinois Pet. at 31-32.

emergency.[106] PIOs and Minnesota and Illinois further assert that MISO has initiated a process to add new capacity over the next several years to address shortfalls.[107]

33. In addition, Michigan AG, PIOs, and Minnesota and Illinois criticize the Emergency Order's references to the President's Executive Order 14156, "Declaring a National Energy Emergency," and Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[108] Minnesota and Illinois assert that the Secretary's references to the President's executive actions evinces "a pretextual effort to further the administration's policy support for fossil fuels."[109]

34. Michigan AG, PIOs, and Minnesota and Illinois also contend that the Emergency Order's citation to the congressional testimony of Jennifer Curran, Senior Vice President, Planning and Operations, MISO, does not support the finding that an emergency exists.[110] PIOs criticize the Secretary's citation to Ms. Curran's testimony because her recommendations did not specifically invoke DOE's use of section 202(c) orders or coal-fired generation.[111]

35. Minnesota and Illinois also state that the Emergency Order failed to consider MISO's purported history of performance in several extreme weather events. According to these parties, MISO is not currently afflicted by any unexpected outage or extreme weather event.[112]

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[106] Michigan AG Pet. at 47-49; PIO Pet. at 53-54, 55-57, 59-60, 65-68; Minnesota and Illinois Pet. at 20-23, 24-26, 32-36.

[107] PIO Pet. at 62; Minnesota and Illinois Pet. at 25.

[108] Michigan AG Pet. at 47 (discussing Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), and Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025)); PIO Pet. at 58-59 (same); *see also* Minnesota and Illinois Pet. at 52-55.

[109] Minnesota and Illinois Pet. at 52.

[110] Michigan AG Pet. at 46 n.187; PIO Pet. at 61-62; Minnesota and Illinois Pet. at 35-36.

[111] PIO Pet. at 61.

[112] Minnesota and Illinois Pet. at 23.

36. Lastly, Michigan AG states that it is unclear whether the Secretary continues to rely upon the evidence cited in support of Order No. 202-25-3.[113]

DOE's Determination

37. The exigencies that section 202(c) is designed to address necessarily require that the Secretary's determination is informed by the facts available at the time and by his sound expert judgment as to what situations constitute an emergency. The statute expressly states that no notice, hearing, or report is required prior to issuance of a section 202(c) order. This confirms that the Secretary is authorized to exercise his section 202(c) authority expeditiously in responding to emergency situations.

38. In any event, the Secretary's determination that an emergency continues to exist is supported by substantial evidence. As discussed above, in the Emergency Order, the Secretary identified the ongoing emergency "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."[114] Consistent with the Secretary's determination, the Emergency Order explains the need to increase capacity—specifically, through the continued operation of the Campbell Plant—to meet increasingly high demands and decreasing generation output.[115]

39. In the Emergency Order, the Secretary first summarized the bases articulated for his factual determinations in the May 2025 Order, such as: (1) the NERC 2025 Summer Reliability Assessment's designation of MISO "at elevated risk of operating reserve shortfalls;" (2) recent retirements of multiple generation facilities in Michigan; (3) the loss of additional resources if the Campbell Plant would have been allowed to retire; and (4) MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, as released in April 2025, which anticipated insufficient capacity for the region containing Michigan.[116]

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[113] Michigan AG Pet. at 40 (citing Department of Energy Order No. 202-25-3 (May 23, 2025) (May 2025 Order)).

[114] *See* Emergency Order at 1.

[115] *See id.* (noting recent closures of generation facilities in Michigan and uncertain near-term future of generation from the Palisades nuclear power plant).

[116] *Id.* at 1-2 (collecting sources).

40. Contrary to Michigan AG's contention,[117] there is no ambiguity as to whether the conditions identified in the May 2025 Order informed the Secretary's determination to issue the Emergency Order. The Secretary stated that, in his expertise and judgment, the "emergency conditions that led to the issuance of Order No. 202-25-3 *continue*, both in the near and long term," and thus "the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer."[118]

41. The Secretary then discussed multiple additional facts that informed his determination that an emergency continues to exist within the meaning of section 202(c). The Secretary explained that the Campbell Plant's operation would continue to be critical to maintaining reliability in MISO, as evidenced by the Campbell Plant's operations during June 2025, repeated MISO alerts to manage grid reliability issued throughout the summer, and forecasted above-normal temperatures for much of the MISO region.[119] Furthermore, the Secretary explained that MISO's resource adequacy emergency is not limited to the summer season, citing MISO's 2022 request for FERC approval of its filing to revise its resource adequacy construct to establish capacity requirements on a seasonal (rather than annual) basis, as well as the December 2023 MISO "Attributes Roadmap," which described anticipated risks due to loss of load for summer and fall moving forward.[120] The Secretary also referenced and quoted from MISO's 2024 report entitled, *MISO's Response to the Reliability Imperative*, wherein MISO again underscored its reliability concerns beyond the summer season.[121]

42. The Secretary further noted that there "is also a potential longer term resource adequacy emergency in MISO," in light of the results of MISO's PRA for the 2025-26 Planning Year.[122] Specifically, MISO noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the areas which include Michigan.[123] The Secretary also cited the 2025 OMS-MISO Survey Results, which projected the need

[117] *See* Michigan AG Pet. at 40.

[118] Emergency Order at 2 (emphasis added).

[119] *Id.* at 2-3.

[120] *Id.* at 3-4.

[121] *Id.* at 4 (discussing *MISO's Response to the Reliability Imperative*).

[122] *Id.*

[123] *Id.* (quoting *Planning Resource Auction—Results for Planning Year 2025–2026*, at 13).

for additional capacity to meet the projected planning reserve margin—principally due to anticipated capacity retirements and increased demand.[124] The Secretary explained that, although MISO had been taking steps to reduce this deficit, extended construction timelines and supply chain constraints are likely to hinder this capacity from coming online to meet demand in the coming years.[125]

43. Petitioners' criticisms regarding the Emergency Order's citations to Ms. Curran's congressional testimony are unconvincing. Contrary to Petitioners' assertions, Ms. Curran's testimony supports the Secretary's emergency determination, even if she did not specifically mention DOE's section 202(c) authority or coal-fired generation. Indeed, Ms. Curran's testimony observed that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[126] Ms. Curran's testimony also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[127] Ms. Curran's testimony recognized "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[128] In short, Ms. Curran's testimony provides important context for the Secretary's action and demonstrates MISO's own concerns regarding the resource adequacy and reliability challenges facing the grid.

44. Similarly, the argument of Minnesota and Illinois that the MISO region does not face current "extreme" weather events misses the mark.[129] The Emergency Order was based on the facts known at the time it was issued on August 20, 2025, including the projected potential for a shortage of capacity in the summer identified by NERC. In other words, it remained critical for the Secretary to act before the shortage materialized. Moreover, contrary to the contentions of Minnesota and Illinois, the conditions that

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[124] *Id.* at 4-5.

[125] *Id.* at 5.

[126] Curran Test. at 5.

[127] *Id.* at 6.

[128] *Id.* at 7.

[129] Minnesota and Illinois Pet. at 22.

actually existed in the summer following issuance of the Emergency Order further confirm the ongoing emergency and sudden increased threats to grid reliability.

45. As noted in the Emergency Order, between June 11 and August 18, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18. Looking to the fall season, DOE notes NERC's 2024 Long-Term Reliability Assessment, as updated July 15, 2025, which highlighted that "MISO has continued the seasonal capacity auction construct and has found growing evidence of risk in non-peak (*e.g.*, spring and fall) seasons. Countering the risk during these off-peak seasons requires more resources to be available, and this can result in less opportunity for generators to pursue their maintenance needs."[130]

46. In any case, seasonal fluctuations in temperature are only one source of generation demand and must be considered among other strains on the grid, particularly increasing and sudden demand from AI data centers and premature retirements of existing generation facilities. On these points, DOE notes a July 2025 report prepared by the Council of Economic Advisers entitled, *The Economic Benefits of Unleashing American Energy* (CEA Report).[131] The CEA Report highlighted rapid energy demand increases due to data centers,[132] while noting that "utilities can delay retirement of existing baseload capacity until a sufficient amount of reliable new generation and storage capacity comes online" to help mitigate price increases associated with heightened demand.[133]

47. The Secretary issued the Emergency Order in the context of and pursuant to the President's executive actions declaring a national energy emergency and ordering DOE to take action to ameliorate the "unprecedented surge in electricity demand driven by rapid

[130] NERC, *2024 Long-Term Reliability Assessment*, at 42 (Dec. 2024, as updated July 15, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

[131] Council of Economic Advisers, *The Economic Benefits of Unleashing American Energy* (July 2025), https://www.whitehouse.gov/wp-content/uploads/2025/03/The-Economic-Benefits-of-Unleashing-American-Energy.pdf.

[132] *Id.* at 2-6.

[133] *Id.* at 7-8. Minnesota and Illinois Exhibit G (MISO Transmission Plan) further supports the need for delayed retirements. The report cautions that current reliability relies on temporary measures such as delayed retirements and imports, warning that, while the energy generation mix continues to evolve, unless more generation is built, "the risks of capacity shortfalls and other reliability issues will continue to grow." *See* Ex. G at 34, 36.

technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing."[134] As the President explained in Executive Order 14262, this significant increase in electricity demand, "coupled with existing capacity challenges, places a significant strain on our Nation's electric grid."[135] Significantly, Executive Order 14262 specifically ordered the Secretary to draw upon "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."[136] The President ordered the Secretary to "develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by [FERC] and [] utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy."[137] PIOs' argument that DOE used this methodology as the basis for issuing the Emergency Order is misplaced. The President did not require this methodology for implementation of section 202(c), and the Emergency Order did not purport to rely upon this methodology in determining the existence of an emergency. The executive orders informed the Secretary's decision and action, in addition to the other factors outlined in the Emergency Order and this Order.

48. The Emergency Order also cited the declared state of national energy emergency established in Executive Order 14156.[138] In declaring such emergency, including pursuant to the National Emergencies Act,[139] the President specifically ordered the heads of executive departments to "identify and exercise any lawful emergency authorities available to them . . . to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources."[140] One such "lawful emergency authorit[y]" is the Secretary's section 202(c) power. PIOs' criticisms of the President's declaration of a national energy emergency in Executive Order 14156

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[134] Emergency Order at 6 (citing Exec. Order 14262 § 1).

[135] Exec. Order 14262 § 1.

[136] *Id.* § 3(c) (emphasis added).

[137] *Id.* § 3(b).

[138] Emergency Order at 4 (citing Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/).

[139] 50 U.S.C. § 1601 *et seq.*

[140] Exec. Order 14156 § 2.

are irrelevant to the Secretary's decision to issue the Emergency Order.[141] Moreover, PIOs' assertion that the national emergency described in Executive Order 14156 is not "specific enough" to demonstrate the existence of an emergency within the meaning of section 202(c) misses the mark. As discussed above, in the Emergency Order, the Secretary determined an emergency exists in the MISO region and undertook lawful action pursuant to his existing emergency authority under section 202(c).

49. In sum, Michigan AG, PIOs, and Minnesota and Illinois maintain that this evidence does not show the existence of an ongoing statutory emergency. But if the Secretary had allowed the planned retirement of the Campbell Plant, then that generating unit would have never been available to address the ongoing emergency in MISO. Accordingly, based on the evidence available, the Secretary reasonably exercised his judgment and issued the Emergency Order in compliance with section 202(c).

4. Best and Appropriate Means for Addressing the Emergency

50. Michigan AG and PIOs raise similar arguments that the Campbell Plant is neither the best nor an appropriate means of alleviating the capacity shortfall addressed by the Emergency Order.[142] In particular, Michigan AG and PIOs argue that DOE was required to consider alternatives and evaluate other possible methods for addressing the emergency, which they argue the Secretary failed to do.[143] They further argue that there are alternative means by which DOE could have addressed the emergency.[144]

51. PIOs additionally argue that the Emergency Order fails to consider the various policies of the FPA.[145] Specifically, PIOs argue that the Emergency Order fails to provide a reasoned basis for its determination that additional dispatch of the Campbell Plant is necessary to best meet the emergency.[146] PIOs further contend that the Emergency Order

[141] *See* PIO Pet. at 43-45.

[142] Michigan AG Pet. at 60-61; PIO Pet. § V.B.

[143] Michigan AG Pet. at 60-61; PIO Pet. at 68-69.

[144] Michigan AG Pet. at 60-61; PIO Pet. § V.B.2.

[145] PIO Pet. at 69.

[146] *Id.* § V.B.2.

does not examine the expense or environmental impact of running the Campbell Plant, or address how the Campbell Plant can meet the emergency.[147]

DOE's Determination

52. The Secretary, in issuing the Emergency Order, adhered to the process established in FPA section 202(c) in exercising his judgment by directing MISO and Consumers Energy to undertake specific actions as to the Campbell Plant.[148] There is no dispute that the Secretary, as the presidentially-appointed and Senate-confirmed head of DOE,[149] is the appropriate individual to determine the existence of an emergency within the meaning of section 202(c) and exercise "[the Secretary's] judgment" as to what actions "best meet the emergency and serve the public interest."[150] As discussed above, the Secretary exercised his discretion in responding to an emergency pursuant to an express delegation of authority under section 202(c). Further, as explained below, there is no basis to grant rehearing to review the Secretary's exercise of his judgment in prescribing the required response to the emergency.

53. As noted above, section 202(c)(1) affords the Secretary discretion as to what remedy "will best meet the emergency and serve the public interest." The statute expressly delegates the decision regarding the appropriate remedy to the Secretary's "judgment" (similar to the express delegation to "determine[] that an emergency exists").[151] Here, the Secretary exercised his judgment in determining that "continued 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)."[152] The Secretary's determination in the May 2025 Order was 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."[153] In the Emergency Order, the Secretary determined that "the emergency

[147] *Id.*

[148] *See generally* Emergency Order.

[149] 42 U.S.C. § 7131.

[150] 16 U.S.C. § 824a(c)(1).

[151] *Id.*

[152] Emergency Order at 7.

[153] *See* May 2025 Order at 2.

conditions that led to the issuance of Order No. 202-25-3 continue, both in near and long term."[154]

54. What is more, PIOs' contention[155] that the Campbell Plant is unreliable is unsupported by their own authorities. Specifically, PIOs point to the fact that, as part of the agreement to retire the Campbell Plant, Consumers Energy agreed to extend the operation of certain units at two other power plants, including units 3 and 4 of the Dan E. Karn Power Plant located in Essexville, Michigan.[156] However, Generation Performance Statistics attached to PIOs' petition indicate that the Campbell Plant generally *outperformed* the Karn units in random outage rates, unit availability, and MWh availability.[157]

55. Petitioners have now identified alternatives they deem to be better and more appropriate solutions to the emergency. But this after-the-fact analysis is irrelevant. Section 202(c)(1) authorizes the Secretary to determine the existence of an emergency and to order the means to address such a statutory emergency. It does not require the Secretary to engage in a lengthy weighing of options or explanation of his actions prior to issuing an emergency order. Indeed, such a process is incompatible with the purpose of the emergency power to act expeditiously and within the judgment of the Secretary.

5. Authority to Order Economic Dispatch

56. Michigan AG, PIOs, and Minnesota and Illinois assert that the Secretary does not have the authority under FPA section 202(c)(1) to order the use of economic dispatch of the Campbell Plant as a response to an emergency, and that economic dispatch is not an effective or rational measure to address resource shortages.[158] According to Michigan AG, PIOs, and Minnesota and Illinois, economic dispatch is not in the public interest, as required under section 202(c).[159] In addition, PIOs contend that the Emergency Order's

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[154] Emergency Order at 2.

[155] PIO Pet. § V.B.2.i.

[156] PIO Pet. at 37.

[157] *See* PIO Exhibit 14 (Michigan Public Service Commission, Generation Performance Statistics January 1, 2023 to December 31, 2023).

[158] Michigan AG Pet. at 62-72; PIO Pet. at 86; Minnesota and Illinois Pet. at 46-52.

[159] *See* Michigan AG Pet. at 62-72; PIO Pet. at 86; Minnesota and Illinois Pet. at 46-52.

economic dispatch requirement is ambiguous and vague.[160] Michigan AG asserts that the possibility of the Campbell Plant's costs exceeding its revenues is "even stronger" than during the May 2025 Order because energy demand will be lower during the fall season, while the Campbell Plant remains operational.[161] Michigan AG asserts that, if this happens, the costs to ratepayers will not have been minimized.[162]

<u>DOE's Determination</u>

57. As noted, FPA section 202(c)(1) affords the Secretary discretion as to what remedy "will best meet the emergency and serve the public interest." The statute expressly delegates the decision on the appropriate remedy to the Secretary's "judgment" (similar to the express delegation to "determine[] that an emergency exists"). In the Emergency Order, the Secretary soundly exercised his judgment to determine that "continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c)."[163] This determination was based on the Secretary's finding that the "emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-3 will continue in the near term and are also likely to continue in subsequent years," as discussed above.[164]

58. The Emergency Order therefore directs MISO and Consumers Energy to "take all measures necessary to ensure that the Campbell Plant is available to operate."[165] The Emergency Order then directs MISO "to take every step to employ economic dispatch of the [facility] to minimize [the] cost to ratepayers."[166]

59. Lastly, DOE disagrees with Michigan AG, PIOs, and Minnesota and Illinois' respective arguments that economic dispatch is not an effective or rational measure to address resource shortages. The Secretary's directive regarding economic dispatch ensures that the Campbell Plant can be dispatched instead of more costly generation (if

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[160] Michigan AG Pet. at 70.

[161] *Id.*

[162] *Id.*

[163] Emergency Order at 7.

[164] *Id.*

[165] *Id.*, Ordering Paragraph A.

[166] *Id.*

available), reducing electricity costs and serving the public interest. The directive recognizes the fact that MISO uses "a production cost modeling software that produces a unit commitment and security-constrained economic dispatch while optimizing production costs."[167] DOE clarifies, however, that to the extent operational (including safety) limitations prevent the Campbell Plant from being economically dispatched, offering the Campbell Plant on a must run basis may be necessary to ensure the units are available to operate.[168] Under those circumstances, such operation would be consistent with minimizing the cost to ratepayers because a price taker can decrease (but cannot increase) the market price.

6. Potential Environmental Impacts

60. Michigan AG, PIOs, and Minnesota and Illinois raise similar arguments that the Emergency Order fails to comply with section 202(c)'s requirement to ensure that any 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."[169] PIOs argue that the Emergency Order may result in a conflict with environment requirements because, for example, Campbell's air pollution control equipment "may not be installed, maintained, and operated in a satisfactory manner," and requiring Campbell to continue operating "may conflict with Michigan's newly-approved regional haze implementation plan and its obligation under the Clean Air Act to reduce haze-causing emissions."[170]

61. In particular, Michigan AG, PIOs, and Minnesota and Illinois argue that the Emergency Order fails to identify any specific criteria or conditions, including the temporal and environmental constraints, for ensuring compliance with environmental

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[167] MISO, *MISO Economic Planning Whitepaper*, at 3 (Oct. 3, 2024), https://cdn.misoenergy.org/MISO%20Economic%20Planning%20Whitepaper651689.pdf

[168] Minnesota and Illinois cite Exhibit Z (Campbell Operation Data) in support of their argument that the Campbell Plant takes 12 hours to reach peak load and therefore makes it unsuitable for emergencies. As a threshold matter, that the Campbell Plant takes 12 hours to reach peak load is unsupported by this exhibit. And in any event, the data reflected in this Exhibit pertains to startup from *cold shutdown*, and therefore only further indicates that to the extent economic dispatch is unavailable, the Campbell Plant should be run on a must run basis so that it remains available for emergency operation.

[169] Michigan AG Pet. at 72-79 (citing 16 U.S.C. § 824a(c)(2)); PIO Pet. at 82-85 (citing 16 U.S.C. § 824a(c)(2)); Minnesota and Illinois Pet. at 41-42 (citing 16 U.S.C. § 824a(c)(2)).

[170] PIO Pet. at 83-85.

regulations or limiting environmental impact.[171] Michigan AG and PIOs further argue that the Emergency Order serves as a renewal or re-issuance of the May 2025 Order, and is therefore subject to section 202(c)(4)(B)'s requirement that DOE "consult[ed] with the primary Federal agency with expertise in the environmental interest protected" by the laws with which the Emergency Order may conflict, with which DOE fails to comply.[172]

DOE's Determination

62. Section 202(c)(2) requires the Secretary to ensure that any section 202(c) order that may result in a conflict with a requirement of any environmental law or regulation to the "maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." In addition, Section 202(c)(2) requires the Secretary to ensure that any section 202(c) order that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest[.]"

63. Contrary to PIOs, Michigan AG, and Minnesota and Illinois' contentions, the Emergency Order contains certain limitations to minimize the hours of operation and adverse environmental impacts. Specifically, the Emergency Order requires that "[a]ll 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,"[173] and requires daily reporting from MISO on "whether the Campbell Plant has operated in compliance with the allowances contained in this Order."[174] These reporting requirements provide a mechanism for DOE to obtain information concerning any adverse environmental impacts of the Emergency Order, and DOE may modify the Emergency Order to require additional actions as the Secretary deems appropriate.

64. Michigan AG and PIOs argue that the Emergency Order is not tailored to respect environmental considerations and express concern about the potential environmental impacts that may be produced by the Campbell Plant.[175] Michigan AG and PIOs provide examples of certain conditions that in their view would, presumably, satisfy the

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[171] Michigan AG Pet. at 76-79; PIO Pet. at 85-88; Minnesota and Illinois Pet. at 41-42.

[172] Michigan AG Pet. at 79; PIO Pet. at 88.

[173] Emergency Order at 8, Ordering Paragraph C.

[174] *Id.*, Ordering Paragraph B.

[175] Michigan AG Pet. at 77-79; PIO Pet. at 86-88.

requirements of the statute (e.g., direction to optimize use of pollution control equipment or avoid operations during air quality episodes,[176] sufficiently detailed reporting obligations to ascertain what impacts result from emergency operations[177]). These conditions, however, are either already included in the Emergency Order or not required by statute and would not necessarily minimize adverse environmental impacts. The Emergency Order requires MISO to provide a daily notification to DOE "reporting whether the Campbell Plant has operated in compliance with the allowances contained" in the Emergency Order.[178] Further, Congress did not prescribe in section 202(c) how DOE was to fulfill its obligations concerning consistency with environmental laws and minimization of adverse effects.

65. Moreover, Congress recognized, by including the phrase "to the maximum extent practicable," that emergency circumstances would at times make compliance with all Federal, state, and local environmental requirements and minimization of all potential adverse environmental impacts infeasible. This phrase provides DOE with discretion in fulfilling its obligations under section 202(c). Accordingly, the Emergency Order's limits on duration, the conditions that authorize only the additional generation necessary, and the requirement that operation of the plant comply with environmental laws to the maximum extent feasible, as well as the reporting requirements that allow DOE to monitor MISO's compliance with the Emergency Order, were sufficient to satisfy the Secretary's obligation under section 202(c)(2).

66. Section 202(c)(4)(B) further requires that, in renewing or reissuing an emergency order, DOE "shall consult with the primary Federal agency with expertise in the environmental interest protected" by laws or regulations with which the Emergency Order may conflict.[179] Prior to issuing the Emergency Order, DOE consulted with the EPA regarding the Campbell Plant's operations. DOE notes that the EPA did not identify any environmental concerns arising from the Campbell Plant's continued operation pursuant to the Emergency Order.

7. NEPA Concerns

67. Michigan AG claims that the Emergency Order violates the National Environmental Policy Act (NEPA), as any orders issued under section 202(c) that affect

[176] Michigan AG Pet. at 78.

[177] PIO Pet. at 88.

[178] Emergency Order at 8, Ordering Paragraph B.

[179] 16 U.S.C. § 824a(c)(4)(B).

the quality of the environment are considered "major federal actions"[180] that require compliance with NEPA standards and requirements.[181] According to Michigan AG, these requirements include the "issuance of an environmental impact statement, environmental assessment, categorical exclusion, or special environmental analysis."[182]

68. Michigan AG further asserts that in other section 202(c) orders, DOE has previously sought to comply with NEPA through categorical exclusions, such as categorical exclusion B4.4 for "power management activities," or special environmental assessments—neither of which has been undertaken in this instance.[183] Lastly, Michigan AG argues that there is no justification to side-step NEPA requirements because DOE had a 90-day lead time to comply with those requirements while the May 2025 Order was in place.[184]

DOE's Determination

69. The Secretary disagrees with Michigan AG's contention that DOE "is acting contrary to its own NEPA regulations and to its obligations under NEPA."[185] Although DOE has previously followed the procedures provided in DOE's NEPA regulations governing emergency actions, as described in 10 C.F.R. § 1021.343 (for example, by preparing a special environmental analysis after the issuance of a section 202(c) order), recent amendments to NEPA clarify that agencies are "not required to prepare an environmental document with respect to a proposed agency action if . . . the preparation of such document would clearly and fundamentally conflict with the requirements of another provision of law."[186] As DOE recently explained in its NEPA Implementing Procedures, "NEPA does not apply to DOE's issuance of emergency Orders pursuant to section 202(c) of the Federal Power Act (16 U.S.C. § 824a(c)) because preparing an

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[180] Michigan AG Pet. at 80-82 (citing 42 U.S.C. § 4336e(10)).

[181] *Id.* at 80.

[182] *Id.* (citing 10 C.F.R. § 1021.102(b)).

[183] *Id.* at 81.

[184] *Id.*

[185] *Id.* at 80.

[186] *See* 42 U.S.C. § 4336(a)(3); *see also* Fiscal Responsibility Act of 2023, Pub. L. No. 188-5, § 321(b), 137 Stat. 10, 39 (2023).

environmental document under NEPA's generally applicable provisions would clearly and fundamentally conflict with the emergency provisions in the Federal Power Act."[187]

70. As discussed above, under FPA section 202(c), Congress explicitly authorized the Secretary to exercise certain emergency authorities "with or without . . . report." Requiring compliance with the analytic and procedural demands of preparing an environmental document under NEPA prior to issuing a section 202(c) emergency order is fundamentally at odds with the congressional authorization to exercise such authorities without report. Accordingly, DOE has determined, in consultation with the Council on Environmental Quality, that "NEPA does not apply to DOE's issuance of emergency orders pursuant to section 202(c) . . . because preparing an environmental document under NEPA's generally applicable provisions would clearly and fundamentally conflict with the emergency provisions in the Federal Power Act."[188] Contrary to Michigan AG's contention, this nexus does not change now merely because DOE has issued a new 202(c) order addressing a continuing emergency.

71. Furthermore, as stated above, section 202(c) specifically provides alternative measures for affording environmental protection by requiring the Secretary to ensure that any 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."[189] Again, those environmental obligations were met through the conditions imposed via the Emergency Order's limitation on the duration of the emergency operations, authorization only of the additional generation necessary, the requirement that operation of the Campbell Plant comply with environmental laws to the maximum extent feasible, and MISO's obligation to report to DOE on its compliance with the Emergency Order and corresponding environmental impacts, if any.

III. Procedural Issues

1. Michigan AG and PIOs' Request for a Stay

72. Michigan AG and PIOs move for a stay of the Emergency Order pending resolution of judicial review. In support of their request, Michigan AG and PIOs contend that:

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[187] U.S. Dep't of Energy, *National Environmental Policy Act* (*NEPA) Implementing Procedures*, at 6 (June 30, 2025), https://www.energy.gov/sites/default/files/2025-06/2025-06-30-DOE-NEPA-Procedures.pdf.

[188] *See id.*

[189] 16 U.S.C. § 824a(c)(2).

(1) absent a stay, they will be irreparably harmed by the Emergency Order; (2) a stay will not harm any other interested parties; and (3) the public interest favors a stay.[190]

DOE's Determination

73. In considering a request for a stay, agencies consider: (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest.[191]

74. By its terms, the Emergency Order terminated on November 19, 2025.[192] Consequently, the stay request is now moot. Michigan AG and PIOs also fail to present evidence of any substantial irreparable harm.

75. In any case, DOE finds that a stay is not warranted here based on a broader consideration of the equities at issue. A stay would have substantially harmed other stakeholders and is therefore not within the public interest. Specifically, the Emergency Order was issued to address a shortage of electric energy and a shortage of facilities for the generation of electric energy in the Midwest region of the United States. As discussed above, this determination is based on the insufficiency of dispatchable capacity and anticipated demand, as well as the risk to public health and safety presented by the potential loss of power to homes and local businesses in areas that may be affected by curtailments or outages. Imposition of a stay would also harm those citizens residing in the Midwest region of the United States who would face potentially critical electric energy shortages, rendering such a stay contrary to the public interest. The balance of equities thus favors denial of a stay.

2. Motions to Intervene

76. Michigan AG, PIOs, and Minnesota and Illinois each moved to intervene in this proceeding, citing various alleged interests which may be affected by the outcome of this proceeding.[193]

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[190] Michigan AG Pet. § V; PIO Pet. § VI.

[191] *See Nken v. Holder*, 556 U.S. 418, 434, 436 (2010); *Ohio v. EPA*, 603 U.S. 279, 291 (2024).

[192] Emergency Order at 9, Ordering Paragraph H.

[193] *See* Michigan AG Pet. § I; PIO Pet. § III; Minnesota and Illinois Pet. at 4-10.

DOE's Determination

77. The motions to intervene in this administrative proceeding are hereby permissively granted for Michigan AG, PIOs, and Minnesota and Illinois to advocate before the agency, but DOE takes no position on whether they are "aggrieved" parties for purposes of FPA section 313 or have constitutional standing.[194]

* * * * *

The Emergency Order is hereby modified upon the issuance of this Order and the result sustained, as discussed in the body of this Order.

Issued at 11:28pm Eastern Standard Time on this 21st day of January 2026.

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Chris Wright
Secretary of Energy

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[194] *See* 16 U.S.C. § 825*l*(b) ("Any party to a proceeding under this chapter aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the United States court of appeals for any circuit wherein the licensee or public utility to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part.").

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 147

NERC Emergency Operations

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-4**

3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. Cold weather conditions; and

1.2.6.2. Extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

8.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

8.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.

   1.2. **Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

   - The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
   - The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
   - The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
   - The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
   - The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

   1.3. **Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**
    - The Balancing Authority 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.
2. **EEA 2 — Load management procedures in effect. Circumstances:**
    - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
    - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 148

Department Press Release on Centralia Order

U.S. DEPARTMENT of ENERGY

Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter

U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months.

Energy.gov

December 17, 2025

2 min

Emergency order addresses critical grid reliability issues, lowering risk of blackouts and ensuring affordable electricity access

WASHINGTON—U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months. The order directs TransAlta to keep Unit 2 of the Centralia Generating Station in Centralia, Washington available to operate. Unit 2 of the coal plant was scheduled to shut down at the end of 2025. The reliable supply of power from the Centralia coal plant is essential for grid stability in the Northwest. The order prioritizes minimizing the risk and costs of blackouts.

"The last administration's energy subtraction policies had the United States on track to experience significantly more blackouts in the coming years — thankfully, President Trump won't let that happen," said **Energy Secretary Wright**. "The Trump administration will continue taking action to keep America's coal plants running so we can stop the price spikes and ensure we don't lose critical generation sources. Americans deserve access to affordable, reliable, and secure energy to heat their homes all the time, regardless of whether the wind is blowing or the sun is shining."

According to DOE's Resource Adequacy Report, blackouts were on track to potentially increase 100 times by 2030 if the U.S. continued to take reliable power offline as it did during the Biden administration.

The North American Electric Reliability Corporation (NERC) determined in its 2025-2026 Winter Reliability

Assessment that the WECC Northwest region is at elevated risk during periods of extreme weather, such as prolonged, far-reaching cold snaps.

This order is in effect beginning on December 16, 2025, and continuing until March 16, 2026.

Background:

The NERC Winter Reliability Assessment warns that “extreme winter conditions extending over a wide area could result in electricity supply shortfalls.” With winter electricity demand continuing to rise, peak demand in the U.S. increased by 2.5% since last winter.

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Energy Department Grants Woodside Louisiana LNG Project Additional Time to Commence Exports

December 16, 2025

Just Launched: A Critical Materials Career Map

December 17, 2025

Tags:

STRENGTHEN GRID RELIABILITY AND SECURITY   EMERGENCY RESPONSE

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 149

DOE Order No. 202-26-01

Department of Energy
Washington, DC 20585

Order No. 202-26-01

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE) Organization Act,[2] and for the reasons set forth below, I hereby determine that a statutory emergency exists in the Electric Reliability Council of Texas, Inc. (ERCOT) region, due to a sudden increase in demand, a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. I direct ERCOT (Reliability Coordinator) and its Balancing Authorities and backup generation resources defined below, to comply with this Order.[3] Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

Throughout the United States, demand is outpacing generation supply. Generation resource inadequacy is especially problematic during prolonged winter cold snaps. According to the North American Electric Reliability Corporation (NERC), "[w]inter electricity demand is rising at the fastest rate in recent years," and the "total internal demand for the [bulk power system] is forecast to increase by 20.2 GW (2.5%) over last winter's forecast.[4] While NERC assesses that there are "adequate resources for normal winter peak-load conditions," NERC cautions that "more extreme winter conditions extending over a wide area could result in electricity supply shortfalls."[5] According to NERC, areas in the continental United States are at an elevated risk during extreme cold, which jeopardizes American lives, our economy, and national security.[6]

In its 2025–2026 Winter Reliability Assessment, NERC finds that the ERCOT assessment area is at elevated risk. According to NERC, above-normal winter peak and outage

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] For all geographical or electrical areas of the Bulk Power System, all areas are under the oversight of one and only one Reliability Coordinator. NERC Rules of Procedure, section 501.1.4.1. All Balancing Authorities are under the responsibility of one and only one Reliability Coordinator. *Id.*, section 501.1.4.2. All Loads and generators are under the responsibility and control of one and only one Balancing Authority. *Id.*, section 501.1.4.4.

[4] *2025-2026 Winter Reliability Assessment*, NERC (NERC 2025-2026 Winter Assessment), at 8 (November 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf. The NERC 2025-2026 Winter Assessment "identifies, assesses, and reports on areas of concern regarding the reliability of the North American [bulk power system] for the upcoming winter season." *Id.* at 4.

[5] *Id.* at 5.

[6] *Id.* at 6.

conditions could result in the need for operating mitigations and Energy Emergency Alerts (EEAs). NERC states that strong load growth is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For this winter season, NERC explains that ERCOT is expected to continue facing reserve shortage risks, particularly under extreme load conditions that accompany freezing temperatures. NERC cautions that load shedding may be needed under wide-area cold weather events.[7]

Under President Trump's leadership, this administration is determined to take swift and decisive action to protect the American people from tragedies, such as Winter Storm Uri, which resulted in "billions of dollars in damages and over 200 deaths."[8]

In Executive Order 14156, "Declaring a National Energy Emergency," President Trump determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[9] In Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "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 increase in domestic manufacturing."[10] These Executive Orders underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns.

The Department's July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy systems. "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)

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[7] NERC, *2025 – 2026 Winter Reliability Assessment*, at 5-6, 31 (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[8] *The February 2021 Cold Weather Outages in Texas and the South Central United States*, FERC, NERC, and Regional Entity Staff Report, at 234 (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and. *See id.* at 189 ("Millions went without heat, lights, refrigeration, and water for days during the Event. Hundreds died from hypothermia or trying to keep warm, in their homes, in their beds.").

[9] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[10] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

innovation."[11] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and increasing source of load growth.

In July 2025, President Trump released America's AI Action Plan for Winning the Race.[12] It recognizes that the "U.S. electric grid is one of the largest and most complex machines on Earth . . . [that] will need to be upgraded to support data centers and other energy-intensive industries of the future."[13] That plan recommended that we stabilize the grid of today as much as possible, including leveraging extant backup power sources to bolster grid reliability during peak demand and optimize existing grid resources as much as possible, including investigating "new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."[14]

NERC-certified Reliability Coordinators and Balancing Authorities[15] are responsible for identifying and addressing emergency conditions on the bulk power system. As discussed below, this is squarely addressed in the mandatory and enforceable NERC Reliability Standard EOP-011-4. Today, calls for voluntary curtailment are authorized under that standard. However, this action gives Reliability Coordinators and Balancing Authorities another tool to avoid the impacts experienced as a result of Winter Storm Uri.

Currently, there are tens of gigawatts of readily available backup generation that have remained largely untapped until now. Deployment of backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system) at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites, can prevent avoidable blackouts, thereby saving lives and reducing costs to the American people.

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[11] Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy at 1(July 2025), https://www.energy.gov/sites/default/files/2025-7/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[12] https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf.

[13] *Id.* at 15.

[14] *Id.*

[15] The North American Electric Reliability Corporation (NERC) certifies Reliability Coordinators and Balancing Authorities in accordance with its Rules of Procedures.

APPLICATION OF EOP-011-4

Section 215 of the Federal Power Act[16] established a framework for development and implementation of mandatory and enforceable Reliability Standards that apply to Bulk Power System owners, operators, and users, such as Reliability Coordinators and Balancing Authorities. NERC certifies Reliability Coordinators and Balancing Authorities pursuant to an Organization Certification program set forth in its Rules of Procedure,[17] because of the significant roles these two functional entity category types have in ensuring bulk power system reliability. A Reliability Coordinator is defined as:

> the entity that is the highest level of authority who is responsible for the Reliable Operation of the [Bulk Electric System (BES)], has the Wide Area view of the BES, and has the operating tools, processes, and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.[18]

A Balancing Authority is "the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time."[19]

Because of the criticality of their respective roles, Reliability Coordinators and Balancing Authorities are subject to NERC's Organization Certification Program to ensure that they have "the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) . . . ."[20]

NERC Reliability Standard EOP-011-4 addresses Emergency Operations. Requirement 2 states "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area." Balancing Authorities are responsible for

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[16] 16 U.S.C. § 824o.

[17] *See generally* NERC Rules of Procedure, https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/nerc-rop-effective-20231128_with-appendicies.pdf; *see also id.* section 500.

[18] NERC Rules of Procedure, Appendix 5B; *see also id.* Appendix 2. Other capitalized terms in this definition also are defined in the NERC Rules of Procedure at Appendix 2.

[19] NERC Rules of Procedure, Appendix 5B; *see also id.* Appendix 2.

[20] NERC Rules of Procedure, section 501.

requesting that their respective Reliability Coordinators issue an Energy Emergency Alert in accordance with Requirement 2 and Attachment 1 to EOP-011-4. Among other things, Balancing Authorities are authorized to make "[p]ublic appeals for voluntary Load reductions" in Requirement 2.2.4. Balancing Authority Operating plans must include provisions in accordance with Requirement 2.2.9 for "Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding" and provisions in accordance with Requirement 2.2.10 to determine reliability impacts of cold weather conditions.

According to Requirement 5,

> Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

According to Requirement 6,

> Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1.

Attachment 1 provides,

> **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
>
> ***
>
> To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.
>
> The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.
>
> ***
>
> Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

> **2.5.1 All available generation units are on line**. All generation capable of being on line in the time frame of the Emergency is on line.
>
> **2.5.2 Demand-Side Management**. Activate Demand-Side Management within provisions of any applicable agreements.
>
> ***
>
> **3.3.1 Energy deficient Balancing Authority obligations.** The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

Of particular note, NERC's 2025-2026 Winter Assessment recognizes that "[p]roactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters."[21] NERC further cautions that Reliability Coordinators and Balancing Authorities "should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions."[22]

EMERGENCY SITUATION

Winter Storm Fern poses significant risks to electric reliability in the Reliability Coordinator's footprint. Consistent with NERC's cautionary notes and this Administration's commitment to grid stability, this order seeks to unlock and deploy backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system) at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites as another tool to mitigate any undue risk to the bulk power system. The employment of this backup generation is expected to reduce stress on the grid. This will permit orderly, safe, and secure operations during Winter Storm Fern.

Consistent with my letter issued on January 22, 2026, ERCOT requested today that DOE issue an order pursuant to FPA section 202(c) to allow the deployment of backup generation during emergency conditions.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy 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," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or

[21] NERC 2025-2026 Winter Assessment at 7.

[22] *Id*.

transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[23] This statutory language constitutes a specific grant of authority to the Secretary to authorize the operation of generation, delivery, and transmission resources that the Secretary has determined will best meet an emergency.

I have made the determination that an emergency exists, due to an abrupt, unexpected increase in demand for electric energy relative to prior forecasts, a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. As discussed above, taking into account the historical data, past projections and planning, and the projections for the upcoming winter season, together with the increasing demand for electricity that has substantially outpaced net generating capacity additions, a statutory emergency exists this winter across the continental United States. As noted above, NERC has warned that winter electricity demand is rising at the fastest rate in recent years and the total internal demand for the bulk power system is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. Even prolonged cold snaps can be expected to lead to the potential loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety during the upcoming winter.

To best meet the emergency and serve the public interest, backup generation resources shall be made available to run during the emergency conditions specified below.

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

A. From January 24, 2026, the Reliability Coordinator and its Balancing Authorities are authorized to direct backup generation resources at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system), to operate as a last resort before declaring an Energy Emergency Alert (EEA) 3 (i.e., before firm load interruption) or during an EEA 3.[24]

B. This Order requires the operation of the backup generation resources described in paragraph A. Following the conclusion of the EEA conditions described in paragraph A, sufficient time for orderly ramp down is permitted, consistent with industry practices.

[23] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[24] *See* NERC Reliability Standard EOP-011-4, Attachment 1, at 3.1 ("The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.").

C. This order is not applicable to any backup generation resource serving a critical reliability or backup need, including those at defense, homeland security, first responder, air traffic control, hospital facilities, 911 call centers, water treatment or wastewater facilities, natural gas pipeline facilities, natural gas gathering facilities, or other similar facilities.

D. To minimize adverse environmental impacts, this Order limits operation of deployed units to the times and within the parameters as determined by the Reliability Coordinator and its Balancing Authorities pursuant to paragraphs A-C.

E. All operations of backup generation resources authorized under this order must otherwise comply with ancillary 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.

F. ERCOT shall provide notification to the Department (via AskCR@hq.doe.gov) within one day following the date any backup generation resources have been directed to operate pursuant to this Order. The reporting shall include a list of all backup generation resources directed to operate pursuant to this Order. ERCOT shall provide such additional information regarding the environmental and other impacts of this Order and their compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

G. Each party affected by this order is directed to file with the Federal Energy Regulatory Commission any tariff, tariff revisions or waivers necessary to effectuate this Order, as applicable. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

H. This Order shall not preclude the need for the backup generation resources subject to this Order to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

I. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, any backup generation resource subject to this Order shall not be considered a capacity resource.

J. This Order shall be effective upon its issuance, and shall expire at 11:59 PM EST on January 27, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 7:34 PM EST on this 24th day of January 2026.

Chris Wright

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Chris Wright
Secretary of Energy

cc: **<u>FERC Commissioners</u>**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

<u>State Commissioners</u>
See Attachment A

Attachment A: State Contact Information

The table below provides contact information for state commissioners within the NERC Reliability Coordinator.

State	Office	Name
TX	Public Utility Commission of Texas	Thomas Gleeson
		Kathleen Jackson
	Railroad Commission of Texas	Christi Craddick
		Wayne Christian
		Jim Wright

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 150

DOE Order No. 202-26-01A

Department of Energy
Washington, DC 20585

Amended Order No. 202-26-01A

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE) Organization Act,[2] and for the reasons set forth below, I hereby determine that a statutory emergency exists in the Electric Reliability Council of Texas, Inc. (ERCOT) region, due to a sudden increase in demand, a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. I direct ERCOT (Reliability Coordinator) and its Balancing Authorities and backup generation resources defined below, to comply with this Order.[3] Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

Throughout the United States, demand is outpacing generation supply. Generation resource inadequacy is especially problematic during prolonged winter cold snaps. According to the North American Electric Reliability Corporation (NERC), "[w]inter electricity demand is rising at the fastest rate in recent years," and the "total internal demand for the [bulk power system] is forecast to increase by 20.2 GW (2.5%) over last winter's forecast.[4] While NERC assesses that there are "adequate resources for normal winter peak-load conditions," NERC cautions that "more extreme winter conditions extending over a wide area could result in electricity supply shortfalls."[5] According to NERC, areas in the continental United States are at an elevated risk during extreme cold, which jeopardizes American lives, our economy, and national security.[6]

In its 2025–2026 Winter Reliability Assessment, NERC finds that the ERCOT assessment area is at elevated risk. According to NERC, above-normal winter peak and outage

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] For all geographical or electrical areas of the Bulk Power System, all areas are under the oversight of one and only one Reliability Coordinator. NERC Rules of Procedure, section 501.1.4.1. All Balancing Authorities are under the responsibility of one and only one Reliability Coordinator. *Id.*, section 501.1.4.2. All Loads and generators are under the responsibility and control of one and only one Balancing Authority. *Id.*, section 501.1.4.4.

[4] *2025-2026 Winter Reliability Assessment*, NERC (NERC 2025-2026 Winter Assessment), at 8 (November 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf. The NERC 2025-2026 Winter Assessment "identifies, assesses, and reports on areas of concern regarding the reliability of the North American [bulk power system] for the upcoming winter season." *Id.* at 4.

[5] *Id.* at 5.

[6] *Id.* at 6.

conditions could result in the need for operating mitigations and Energy Emergency Alerts (EEAs). NERC states that strong load growth is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For this winter season, NERC explains that ERCOT is expected to continue facing reserve shortage risks, particularly under extreme load conditions that accompany freezing temperatures. NERC cautions that load shedding may be needed under wide-area cold weather events.[7]

Under President Trump's leadership, this administration is determined to take swift and decisive action to protect the American people from tragedies, such as Winter Storm Uri, which resulted in "billions of dollars in damages and over 200 deaths."[8]

In Executive Order 14156, "Declaring a National Energy Emergency," President Trump determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[9] In Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "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 increase in domestic manufacturing."[10] These Executive Orders underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns.

The Department's July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy systems. "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)

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[7] NERC, *2025 – 2026 Winter Reliability Assessment*, at 5-6, 31 (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[8] *The February 2021 Cold Weather Outages in Texas and the South Central United States*, FERC, NERC, and Regional Entity Staff Report, at 234 (November 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and. *See id.* at 189 ("Millions went without heat, lights, refrigeration, and water for days during the Event. Hundreds died from hypothermia or trying to keep warm, in their homes, in their beds.").

[9] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[10] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

innovation."[11] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and increasing source of load growth.

In July 2025, President Trump released America's AI Action Plan for Winning the Race.[12] It recognizes that the "U.S. electric grid is one of the largest and most complex machines on Earth . . . [that] will need to be upgraded to support data centers and other energy-intensive industries of the future."[13] That plan recommended that we stabilize the grid of today as much as possible, including leveraging extant backup power sources to bolster grid reliability during peak demand and optimize existing grid resources as much as possible, including investigating "new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."[14]

NERC-certified Reliability Coordinators and Balancing Authorities[15] are responsible for identifying and addressing emergency conditions on the bulk power system. As discussed below, this is squarely addressed in the mandatory and enforceable NERC Reliability Standard EOP-011-4. Today, calls for voluntary curtailment are authorized under that standard. However, this action gives Reliability Coordinators and Balancing Authorities another tool to avoid the impacts experienced as a result of Winter Storm Uri.

Currently, there are tens of gigawatts of readily available backup generation that have remained largely untapped until now. Deployment of backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system) at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites, can prevent avoidable blackouts, thereby saving lives and reducing costs to the American people.

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[11] Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy at 1(July 2025), https://www.energy.gov/sites/default/files/2025-7/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[12] https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf.

[13] *Id.* at 15.

[14] *Id.*

[15] The North American Electric Reliability Corporation (NERC) certifies Reliability Coordinators and Balancing Authorities in accordance with its Rules of Procedures.

APPLICATION OF EOP-011-4

Section 215 of the Federal Power Act[16] established a framework for development and implementation of mandatory and enforceable Reliability Standards that apply to Bulk Power System owners, operators, and users, such as Reliability Coordinators and Balancing Authorities. NERC certifies Reliability Coordinators and Balancing Authorities pursuant to an Organization Certification program set forth in its Rules of Procedure,[17] because of the significant roles these two functional entity category types have in ensuring bulk power system reliability. A Reliability Coordinator is defined as:

> the entity that is the highest level of authority who is responsible for the Reliable Operation of the [Bulk Electric System (BES)], has the Wide Area view of the BES, and has the operating tools, processes, and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.[18]

A Balancing Authority is "the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time."[19]

Because of the criticality of their respective roles, Reliability Coordinators and Balancing Authorities are subject to NERC's Organization Certification Program to ensure that they have "the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) . . . ."[20]

NERC Reliability Standard EOP-011-4 addresses Emergency Operations. Requirement 2 states "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area." Balancing Authorities are responsible for

[16] 16 U.S.C. § 824o.

[17] *See generally* NERC Rules of Procedure, https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/nerc-rop-effective-20231128_with-appendicies.pdf; *see also id.* section 500.

[18] NERC Rules of Procedure, Appendix 5B; *see also id.* Appendix 2. Other capitalized terms in this definition also are defined in the NERC Rules of Procedure at Appendix 2.

[19] NERC Rules of Procedure, Appendix 5B; *see also id.* Appendix 2.

[20] NERC Rules of Procedure, section 501.

requesting that their respective Reliability Coordinators issue an Energy Emergency Alert in accordance with Requirement 2 and Attachment 1 to EOP-011-4. Among other things, Balancing Authorities are authorized to make "[p]ublic appeals for voluntary Load reductions" in Requirement 2.2.4. Balancing Authority Operating plans must include provisions in accordance with Requirement 2.2.9 for "Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding" and provisions in accordance with Requirement 2.2.10 to determine reliability impacts of cold weather conditions.

According to Requirement 5,

> Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

According to Requirement 6,

> Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1.

Attachment 1 provides,

> **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
>
> ***
>
> To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.
>
> The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.
>
> ***
>
> Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

> **2.5.1 All available generation units are on line**. All generation capable of being on line in the time frame of the Emergency is on line.
>
> **2.5.2 Demand-Side Management**. Activate Demand-Side Management within provisions of any applicable agreements.
>
> ***
>
> **3.3.1 Energy deficient Balancing Authority obligations.** The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

Of particular note, NERC's 2025-2026 Winter Assessment recognizes that "[p]roactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters."[21] NERC further cautions that Reliability Coordinators and Balancing Authorities "should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions."[22]

EMERGENCY SITUATION

Winter Storm Fern poses significant risks to electric reliability in the Reliability Coordinator's footprint. Consistent with NERC's cautionary notes and this Administration's commitment to grid stability, this order seeks to unlock and deploy backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system) at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites as another tool to mitigate any undue risk to the bulk power system. The employment of this backup generation is expected to reduce stress on the grid. This will permit orderly, safe, and secure operations during Winter Storm Fern.

Consistent with my letter issued on January 22, 2026, ERCOT requested today that DOE issue an order pursuant to FPA section 202(c) to allow the deployment of backup generation during emergency conditions.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy 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," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or

[21] NERC 2025-2026 Winter Assessment at 7.

[22] *Id*.

transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[23] This statutory language constitutes a specific grant of authority to the Secretary to authorize the operation of generation, delivery, and transmission resources that the Secretary has determined will best meet an emergency.

I have made the determination that an emergency exists, due to an abrupt, unexpected increase in demand for electric energy relative to prior forecasts, a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. As discussed above, taking into account the historical data, past projections and planning, and the projections for the upcoming winter season, together with the increasing demand for electricity that has substantially outpaced net generating capacity additions, a statutory emergency exists this winter across the continental United States. As noted above, NERC has warned that winter electricity demand is rising at the fastest rate in recent years and the total internal demand for the bulk power system is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. Even prolonged cold snaps can be expected to lead to the potential loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety during the upcoming winter.

To best meet the emergency and serve the public interest, backup generation resources shall be made available to run during the emergency conditions specified below.

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

A. From January 24, 2026, the Reliability Coordinator and its Balancing Authorities are authorized to direct backup generation resources at data centers (including but not limited to hyperscaler facilities), and at other large load industrial and commercial customer sites (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system), to operate after ERCOT deploys all available market services, except for frequency responsive services, before declaring an Energy Emergency Alert (EEA) 3 (i.e., before firm load interruption) or during an EEA 3.[24]

B. This Order requires the operation of the backup generation resources described in

[23] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[24] *See* NERC Reliability Standard EOP-011-4, Attachment 1, at 3.1 ("The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2."). *Cf.* Tex. Util. Code § 37.0561(e) ("After the independent organization deploys all available market services, except for frequency responsive services, the independent organization may direct the applicable electric utility or municipally owned utility to require the large load customer to either deploy the customer's on-site backup generating facilities or curtail load. The independent organization shall include a deployment under this section as firm load shed when calculating any price adjustments for reliability deployments.").

paragraph A. Following the conclusion of the EEA conditions described in paragraph A, sufficient time for orderly ramp down is permitted, consistent with industry practices.

C. This order is not applicable to any backup generation resource serving a critical reliability or backup need, including those at defense, homeland security, first responder, air traffic control, hospital facilities, 911 call centers, water treatment or wastewater facilities, natural gas pipeline facilities, natural gas gathering facilities, or other similar facilities.

D. To minimize adverse environmental impacts, this Order limits operation of deployed units to the times and within the parameters as determined by the Reliability Coordinator and its Balancing Authorities pursuant to paragraphs A-C.

E. All operations of backup generation resources authorized under this order must otherwise comply with ancillary 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.

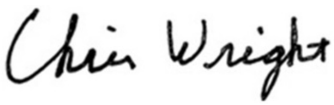
F. ERCOT shall provide notification to the Department (via AskCR@hq.doe.gov) within one day following the date any backup generation resources have been directed to operate pursuant to this Order. The reporting shall include a list of all backup generation resources directed to operate pursuant to this Order. ERCOT shall provide such additional information regarding the environmental and other impacts of this Order and their compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

G. This Order shall not preclude the need for the backup generation resources subject to this Order to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, any backup generation resource subject to this Order shall not be considered a capacity resource.

I. This Order shall be effective upon its issuance, and shall expire at 11:59 PM EST on January 27, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 1:46 PM EST on this 25th day of January 2026.



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Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

State Commissioners
See Attachment A

Attachment A: State Contact Information

The table below provides contact information for state commissioners within the NERC Reliability Coordinator.

State	Office	Name
TX	Public Utility Commission of Texas	Thomas Gleeson
		Kathleen Jackson
		Courtney K. Hjaltman
		Morgan Johnson
	Railroad Commission of Texas	Christi Craddick
		Wayne Christian
		Jim Wright