2026–2027 Winter Reliability Assessment

November 2026

RELIABILITY | RESILIENCE | SECURITY

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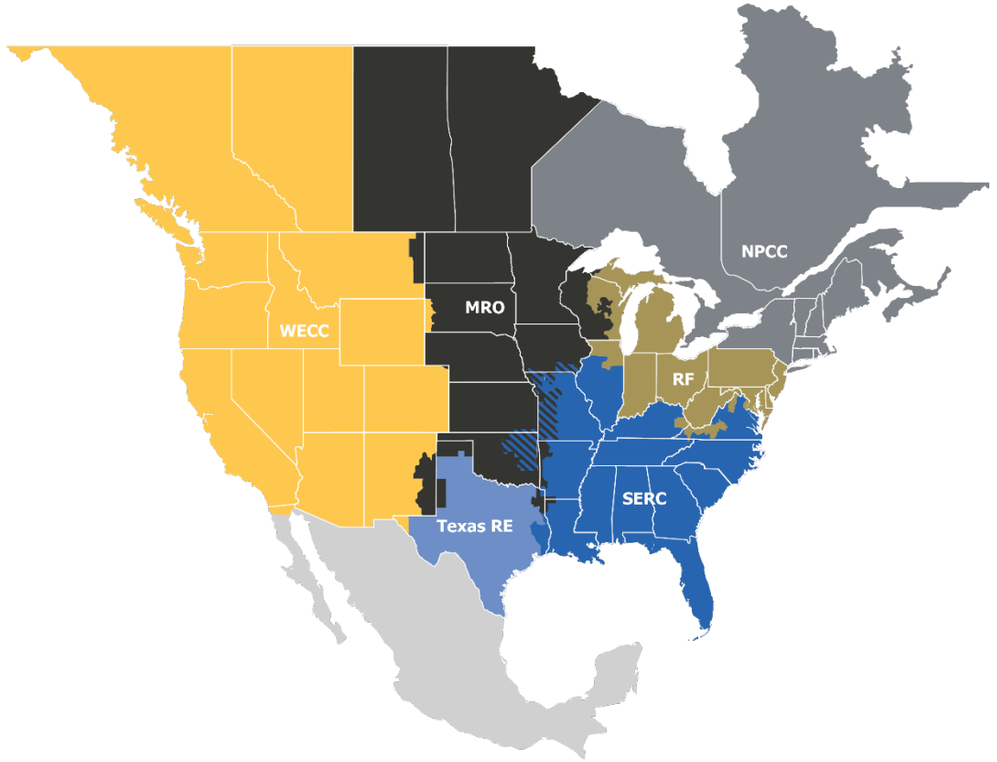
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Preface

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

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is 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 *2026–2027 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.

This 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 take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming 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. The assessment is based on deterministic evaluation of data submitted for peak demand hour and risk hours as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern.

While the scope of this seasonal assessment is focused on the upcoming winter, the key findings are consistent with risks and issues that NERC highlighted in the *2025 Long-Term Reliability Assessment* (LTRA), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1] Overall, three major trends have been identified in this WRA.

1. **Growth in winter resource capacity has improved the overall reliability outlook.** While electricity demand continues to escalate with the addition of new computational and industrial loads and continued electrification across sectors, the capacity of BPS resources for the upcoming winter has also risen sharply. The North American BPS is demonstrating accelerated load growth with aggregated peak demand across all assessment areas increasing by 21 GW (2.6% growth) since last winter, surpassing the previous year-over-year gain of 20 GW. Total BPS resources during the year grew by 26 GW (2.4%) in terms of winter on-peak capacity. The resource types adding the most winter capacity were batteries (20.6 GW nameplate/9.2 GW on-peak capacity added) and natural-gas-fired generation (8.7 GW added). See **Escalating Winter Demand** and **Resource Trends.**

2. **Operational risks during wide-area cold snaps continue to highlight fuel assurance challenges, as observed over the past several years.** Natural-gas-fired fuel availability for power generation remains a key reliability issue. Freezing temperatures can drive up heating demand while simultaneously disrupting fuel supply. It is critical to secure fuel delivery and coordinate electric-gas operations during these periods to ensure grid stability during extreme weather events. The *2026–2027 WRA* includes a new analysis of **Risks and Trends Related to the Natural Gas System for the Upcoming Winter**.

3. **System operators are employing additional flexibility options, obtained through emergency mechanisms, to mitigate forecasted electricity shortfalls**. Prior to deploying some demand-response (DR) resources that can lower demand during periods of grid stress, system operators in PJM, MISO, and some other areas must declare energy emergencies. More large loads, data centers, and large industrial and commercial end users are participating in DR programs, causing DR for this winter to increase by 1.9 GW (4.5%). In addition to DR resources, Balancing Authorities (BA) in some U.S. areas have requested and received authorizations from the U.S. Department of Energy (DOE) Emergency Orders to expand the use of 202c exemptions as a last resort to ensure maximum generation availability in Energy Emergency events. See **U.S. Federal Power Act Emergency Authority**.

NERC anticipates that familiar winter challenges and the unpredictability of the El Niño climate pattern have the potential to disrupt reliable electricity supply and natural gas fuel for BPS generators. Recommendations in this report and lessons learned from the Winter 2026 Arctic Events system performance review will help system operators and energy officials prepare and operate for potentially extreme winter conditions.

The following are notable findings from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity for the upcoming winter:

1. Adequate resources for normal winter peak-load conditions (i.e., 50-50 peak demand forecast) are available across the BPS. However, more extreme winter conditions extending over a wide area could result in supply shortfalls in some assessment areas. 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. The following areas face risks of supply shortfalls during periods of more extreme conditions this winter (see **Figure 1**).

    - **NPCC-Maritimes:** Reserve margins have changed little since last winter as resources, including DR and available generation, rose along with forecasts for higher peak demand. To meet normal or more extreme peak demand and prepare for potential generator outages, system operators in NPCC-Maritimes are likely to arrange for additional energy transfers with neighbors. NPCC's all-hours probabilistic analysis for the NPCC Region found that sufficient regional supplies were available under a range of conditions to address shortfall risks in NPCC-Maritimes and across the Region.

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

NPCC-Maritimes has not identified operational issues expected to impact system reliability. Day-ahead and real-time power purchases, on-site heavy fuel oil (HFO) supplied to dual-fuel generating units, and long-term energy contracts will be crucial to providing flexibility for the area to prepare for potential natural gas supply disruptions that may also align with high demand.

- **NPCC-Québec:** NPCC-Québec is entering the upcoming winter period with a smaller net reserve margin when compared to the previous year. The main driver is an increase in known outages, giving a 1,500 MW reduction in certain generation capacity that is only partially offset by a ~500 MW reduction in net firm exports. While Anticipated Reserve Margins (ARM) are slightly above Reference Margin Levels and no hydropower performance or fuel supply issues are currently anticipated, expected resources may not meet reserve requirements under certain extreme peak demand scenarios. The highest operational risk occurs during peak demand hours (system peak typically occurs in mornings around the hour ending at 8:00 a.m.). Under severe winter load or high system outage scenarios, operators may need to deploy operational mitigations.
- **SERC-East:** SERC-East is historically a summer-peaking area that is increasingly experiencing higher winter peak demand year-over-year. This change to winter peak demand is driving a decline in the ARM. Continued load growth across the residential, commercial, industrial, and large load sectors has impacted the area's load profile during early morning winter peak conditions. Expected resources meet operating reserves under normal peak demand, and no significant fuel or transmission constraints are expected. However, severe winter conditions pose an elevated risk to the region. Probabilistic assessments indicate that limited loss-of-load risk is concentrated around January early-morning hours, where extreme cold weather can increase heating demand, reduce generation availability, and restrict imports.

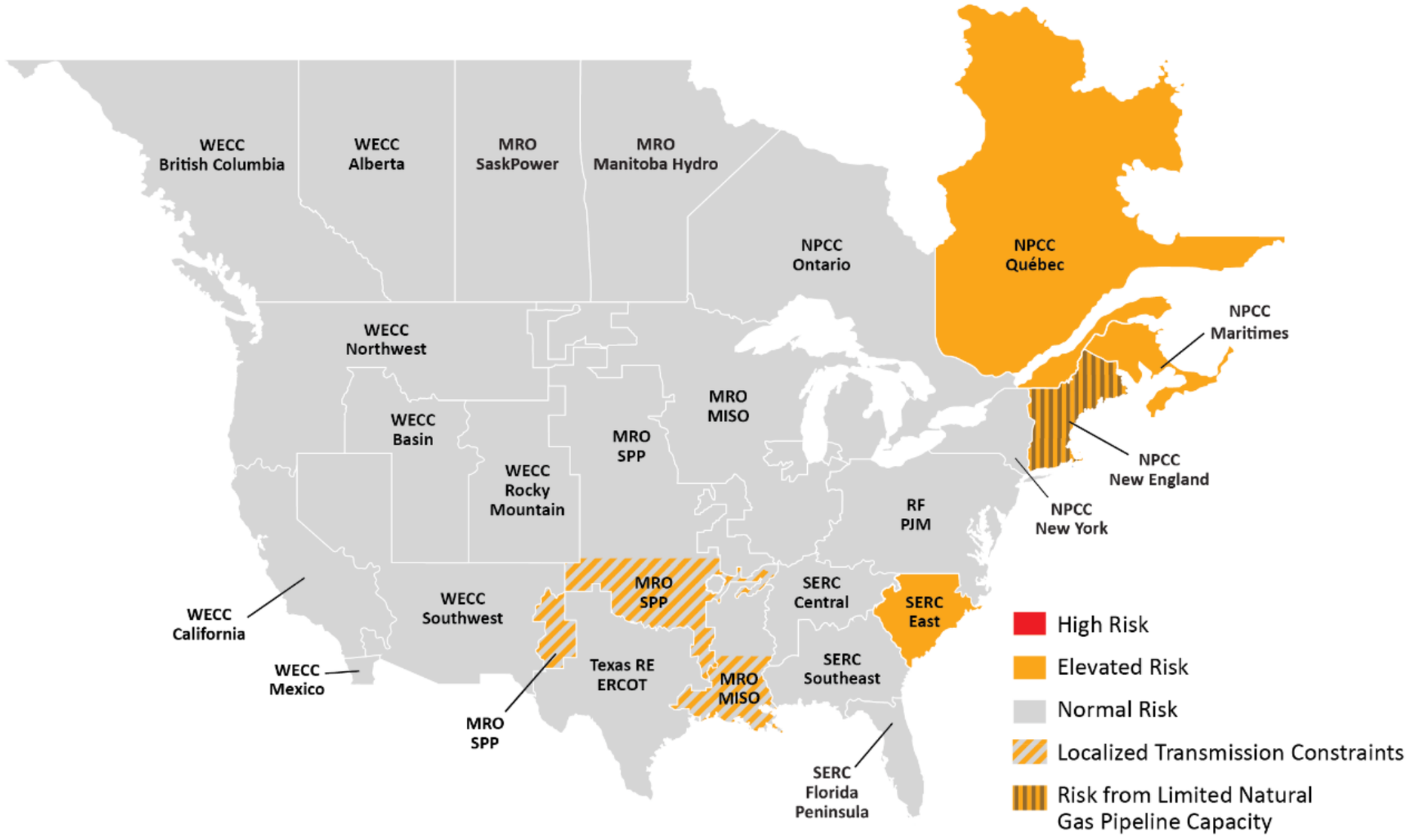


Figure 1: Winter Reliability Risk Area Summary

2. When system operators at BAs determine that scheduled resources may fall short of forecasted demand and operating reserve requirements, they take various mitigating actions specified in their operating plans and procedures. Mitigations generally include some or all of the following actions, escalating from days-ahead operations planning to real-time operations:
   - Arrange additional supply via short-term contracts.
   - Coordinate regionally with other BAs for additional (non-firm) imports.
   - Issue resource advisories, maximum generation alerts, and conservative operating protocols. Coordinate with Generator Owners (GO) for requesting environmental waivers to maximize generator availability, if appropriate.
   - Coordinate with load-serving entities to issue public appeals for conservation.
   - Employ DR resources through load-serving entities.
   - When a BA is energy deficient or projected to be energy deficient, the BA communicates with the Reliability Coordinator (RC) for issuing an Energy Emergency Alert (EEA).[2] Some DR resources are only available for use after an EEA is declared. Additionally, BAs in the United States with data centers and large loads may seek emergency authority from the DOE to direct large load customers to use backup generators as a last resort to reduce demand and avoid energy shortfalls. See **U.S. Federal Power Act Emergency Authority**.
3. In the following areas, electricity supply shortfalls are not expected; however, transmission system constraints, fuel risk scenarios, or other potential impacts are identified that could preclude serving some load pockets under certain conditions.
   - **MRO-MISO:** MISO projects adequate reserves for normal and above-normal peak conditions for the MISO area. Long-term transmission projects in MISO are underway to address load growth, generation development, and reliability needs. Until completed, system operators may need to manage challenging congestion patterns that can emerge under extreme conditions. Under non-typical system flows, restricted transfer capabilities, or unexpected transmission or generator outages, import-dependent load pockets in the south part of MISO are at risk of potential energy deficits.
   - **MRO-SPP:** Winter peak demand for the Southwest Power Pool (SPP) footprint is expected to increase by approximately 3.5% compared to the prior WRA. Continued load growth and capacity changes have resulted in a decline in the area's ARM. Expected resources meet operating reserve requirements for normal and more extreme peak conditions. Extreme winter weather, however, remains a primary operational risk in the assessment area. Import-dependent pockets within the southern part of the assessment area could face localized reliability challenges during periods of high demand or adverse weather due to insufficient import capability. These challenges are driven by factors that include increasing winter peak loads, timing of critical transmission upgrades, and the ongoing evolution of the generation fleet, which can impact both energy and capacity adequacy.
   - **NPCC-New England:** ISO New England (ISO-NE) expects to satisfy its regional transmission and resource adequacy minimum reserve requirements for the upcoming winter period. Probabilistic assessments indicate minimal overall energy shortfall risk under extreme conditions. Expected resources meet operating reserves for normal peak demand, and ISO-NE projects sufficient capacity to cover both 50/50 and 90/10 winter peak forecasts. Operators at ISO-NE closely monitor generator fuel availability due to persistent concerns with fuel supplies during extreme conditions. In cold snaps, when demand for natural gas peaks simultaneously for both electric generation and heating end users, the flow of fuel through constrained pipelines can fall short of energy needs. Over half of the natural-gas-fired generators in the assessment area (9.3 GW of the total 17.8 GW natural gas generation) have alternate stored fuels. Prolonged extreme weather events, like the conditions experience in 2012–2013, have shown that stored generator fuel supplies in NPCC-New England can become rapidly depleted and frozen waterways and roads make resupply efforts difficult. ISO-NE's 21-Day Energy Assessment provides stakeholders with early indications of fuel availability issues and reduces the risk of energy shortfall. However, the underlying concern of stored fuel depletion in a long-duration cold weather event remains.

[2] Energy Emergency Alerts are described in Reliability Standard EOP-011-4 (Emergency Operations) Attachment 1.

4. The reliability outlook in some areas has improved and led to a lower risk determination for this WRA compared to last winter. Resource additions, minimal generator retirements, and enhanced modeling contributed to increases in winter capacity. Factors affecting the improved outlook are described below:

   - **Texas RE-ERCOT:** Resource growth in terms of peak-demand capacity has largely kept pace with demand growth. Winter peak capacity has increased with addition of 1.7 GW in natural-gas-fired generation and nearly 3.5 GW in new battery installed capacity. Higher expected contribution from wind resources is also contributing to more expected supply. Extreme demand forecasts (99th percentile) are lower than in previous assessments as a result of revisions for observed behavior of residential and industrial loads including cryptocurrency facilities. Winterization standards for generators and wind turbines have improved cold-weather performance. Market products are being implemented to provide improved fuel assurance.
   - **WECC-Basin:** The assessment area reports more on-peak capacity this winter as a result of resource additions and model improvements. Converted natural-gas-fired generators (320 MW) became operational to add capacity for the upcoming winter and keep pace with demand growth. The addition of 1,000 MW in nameplate battery capacity provides more flexibility during fluctuations in demand and variable energy resource output. WECC's Interconnection-wide analysis also shows that the Basin assessment area can import more during peak demand periods, benefiting from surplus energy in neighboring areas through interregional transfer capability.
   - **WECC-Northwest:** Forecasted demand has risen slightly since last winter. The *2026–2027 WRA* uses new probabilistic resource adequacy modeling tools that include more hydro resource capability and wind contributions during peak demand periods. The new modeling, along with growth in resources across the U.S. West, alleviates shortfall risks for WECC-Northwest that were identified for the prior winter.

Recommendations

Maintaining reliability this winter requires being prepared for both familiar winter challenges and unexpected conditions that could occur during the El Niño year. In recent years, wide-area, long-duration extreme cold events have stressed the BPS and natural gas fuel infrastructure. The 2026 Cold Weather Performance Review describes the proactive actions taken in January 2026 to mitigate risks and avoid manual load-shedding. This performance review and a comprehensive set of resources are available on NERC's Cold Weather Risk Mitigation initiatives page.

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

- RCs, BAs, and Transmission Operators (TOP) 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. Successive overlapping arctic air mass events in January 2026 demonstrated the need for operations planning to consider the potential for extreme conditions to last for 10 days or more and stress the endurance of the BPS, natural gas infrastructure, and operators. Operators should review NERC's ERO Enterprise Extreme Cold Weather - Themes and Best Practices.
- 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.[3]
- 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 in addition to maintaining contact with pipeline operators and prepare responses to any impactful operational flow orders.[4] 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.

[3] In the annual Cold Weather Data informational filing submitted to FERC On October 1, 2026, and based on the data reported this year, NERC states that 99% of the total net winter capacity in the continental U.S. responded that they were able to operate at the calculated Extreme Cold Weather Temperature (ECWT). Additionally, 94% of the total net winter capacity reported an ECWT at or below 32°F and would be required to apply freeze protection measures to operate during the winter. NERC also found that 60% of the total reported net winter capacity under a corrective action plan (CAP) during winter 2025-2026 will be completed before winter 2026–2027, indicating a very high percentage of the total net winter capacity in every region being reported as operable at the ECWT.

[4] Report | System Performance Review of the Winter 2026 Arctic Cold Period | Federal Energy Regulatory Commission

Risk Highlights

Winter Temperature and Precipitation Forecast

The winter season presents unique challenges to BPS reliability. NOAA's US Winter Outlook shows how El Niño will likely influence the upcoming winter months (December 2026–February 2027), with warmer-than-average temperatures expected across the northern United States; wetter-than-average conditions likely across the southern United States, from California to Florida, and along the Eastern Seaboard; and drought improving for the majority of the country, including areas in the East, Southern Great Plains, and Southwest.[5] See **Figure 2**.

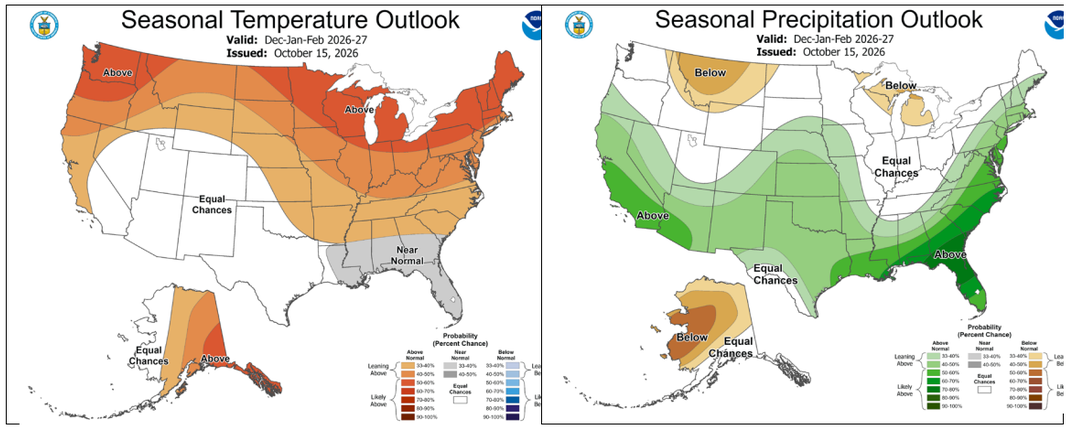


Figure 2: U.S. Winter Temperature and Precipitation Outlook

Similarly, Environment and Climate Change Canada predicts higher-than-normal temperatures across much of Canada with lower-than-normal precipitation outside the Maritimes. Environment and Climate Change Canada temperature forecasts for November 2026 through March 2027 are shown in **Figure 3**.

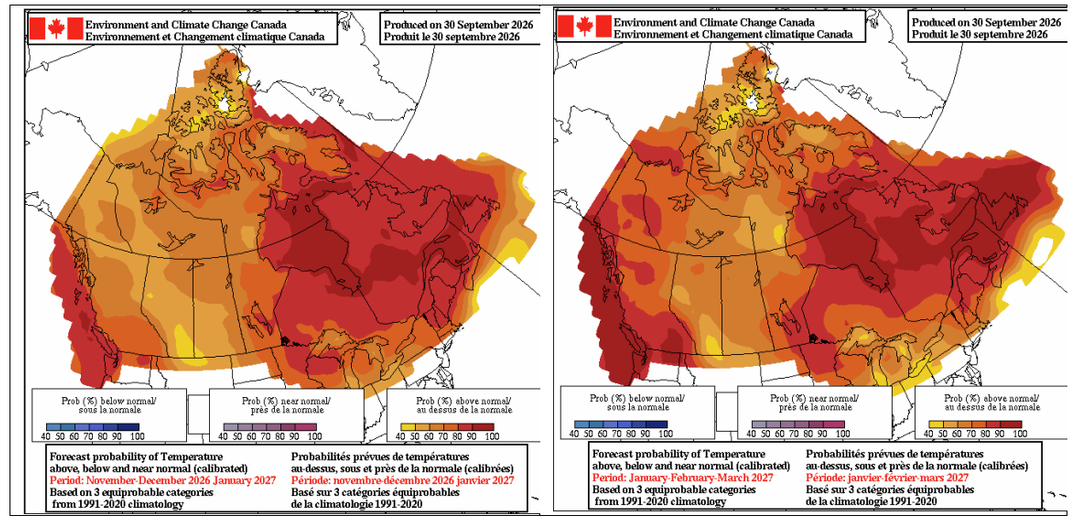


Figure 3: Canada Winter Temperature Outlook[6]

Importantly, El Niño conditions can temporarily alter normal winter air flows and pressure regions, causing winter storm tracks to follow atypical paths. Warmer areas can be subject to abnormal freezing events and cold snaps, making it especially challenging to maintain grid reliability. When unseasonably warm and wet conditions change rapidly to freezing temperatures, winterization measures taken to protect generators, wind turbines, and natural gas fuel production and supply infrastructure are severely tested.

[5] El Nino looms large over U.S. Winter Outlook | National Oceanic and Atmospheric Administration

[6] Temperature and Precipitation Probabilistic Forecasts - Environment Canada

Resource Adequacy Outlook

While electricity demand continues to escalate with the addition of new computational and industrial loads and continued electrification across sectors, the capacity of BPS resources for the upcoming winter has also risen sharply (see **Figure 4**). A review of demand and resource trends since Winter 2025–2026 is in the sections that follow.

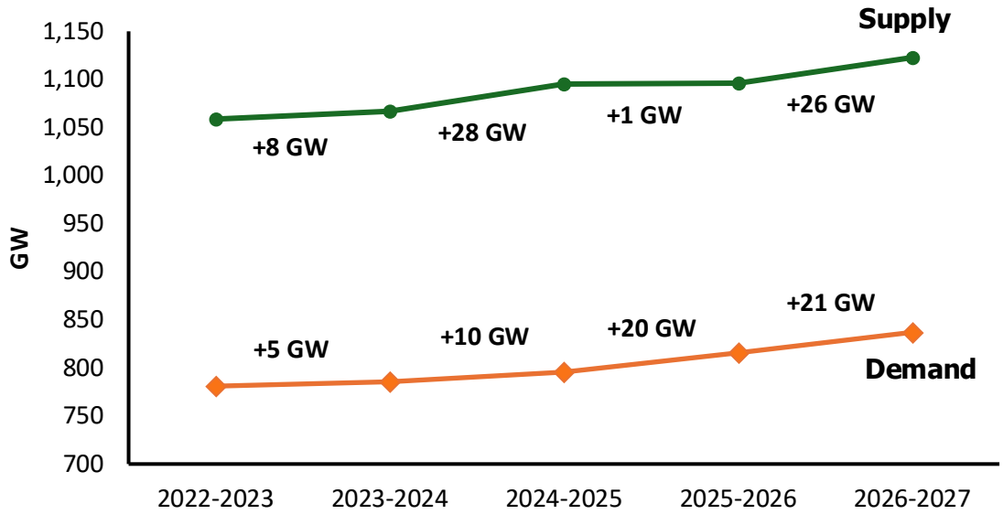


Figure 4: Winter On-Peak Supply and Demand
Aggregated Anticipated Resources and Total Internal Demand for All Assessment Areas
Current and Prior NERC WRAs[7]

Escalating Winter Demand

Electricity demand continues to climb rapidly, driven by the expansion of data centers, large industrial loads, and broad electrification across end-use sectors; 21 of the 23 NERC assessment areas are forecast for higher peak electricity demand this winter, continuing the trend from the past several winter seasons. (See **Net Internal Demand** for regional growth details.) Aggregated peak demand across all assessment areas has increased by 21 GW (2.6% growth) since last winter, surpassing the previous year-over-year gain of 20 GW (see **Figure 4**).

While new electricity loads drive overall peak demand higher, DR programs provide operators with additional tools to manage load during periods of grid stress. Total DR resources grew from 41.7 GW last winter to 43.6 GW this winter (+1.9 GW). These resources primarily consist of commercial and industrial loads that have agreements with load-serving entities to curtail electricity usage during specific conditions, subject to contractual limits (such as annual call limits, designated seasons, or duration caps). Additional demand-side relief during grid emergencies can be achieved through data centers transitioning to on-site backup generation, particularly under U.S. DOE emergency orders issued pursuant to Section 202(c) of the Federal Power Act (see **U.S. Federal Power Act Emergency Authority**).

Resource Trends

Growth in winter resource capacity has improved the overall reliability outlook. Total BPS resources during the year grew by 26.2 GW (2.4%) in terms of winter on-peak capacity. Resource types that added the most winter capacity were batteries and natural-gas-fired generation. See **Table 1**.

Table 1: BPS Resource Capacity Additions Since Winter 2025–2026

Resource Type	On-Peak Capacity Added (GW)
Battery	9.2
Natural Gas	8.7
Wind	3.6
Solar	1.3
Hybrid and Other Resource Types	0.6
Total Resource Additions[8]	23.4[9]

[7] Values in Figure 4 are resource and demand forecasts from prior NERC Winter Reliability Assessments. Forecast values, rather than actual historical peak demand, are used because they provide a weather-normalized perspective of load growth. Actual historical peak demand values can be found in NERC Electricity Supply and Demand (ES&D) data set.

[8] On-peak capacity additions were calculated from generator data collected by NERC for the 2026 Long-Term Reliability Assessment (LTRA) and include all new generators added since last winter as well as expected generator additions for the upcoming winter, as of LTRA data collection deadline in July 2026.

[9] The growth in winter on-peak capacity from the 2025-2026 WRA to 2026-2027 WRA is 26.2 GW, calculated from aggregate Anticipated Resources for all assessment areas. See **Demand and Resource Tables**. Resource additions shown in Table 1 account for most of this capacity growth (23.4 GW). Other sources of capacity change since last winter include generator retirements, generator scheduled maintenance, on-peak capacity contribution values determined by the assessment areas, and modeling or method changes. WECC's recent change in resource adequacy modeling tools affected hydro capacity contributions across the Western Interconnection.

A slowdown in generator retirements is also contributing to the improved resource outlook for the upcoming winter. As of September 2026, total retirement of thermal generators 50 MW and larger in the United States for 2026 was under 700 MW. With little capacity exiting the BPS, the net effect of resource additions described in **Table 1** is strong growth in capacity.

Across the three major Interconnections, solar and wind additions continue to expand the footprint of variable energy resources (VER) heading into the 2026–2027 Winter season (see **Table 2**).[10] Solar photovoltaic additions represent the vast majority of new VER nameplate capacity, adding 16,957 MW in the Eastern Interconnection, 6,383 MW in Texas (ERCOT), and 875 MW in the Western Interconnection. Wind additions show moderate growth across regions, led by 2,706 MW in the Eastern Interconnection and 2,250 MW in the Western Interconnection, alongside a modest 16 MW addition in Texas. While these substantial nameplate capacity additions enhance total energy availability across the BPS, their operational contribution during winter peak periods remains heavily derated due to potential low wind and solar availability during morning and evening peak demand hours.

Table 2: BPS Variable Energy Resource (VER) Change from Winter 2025–2026 to Winter 2026–2027

Resource	Net Change Nameplate Capacity (MW)
Eastern Interconnection	
Solar	16,957
Wind	3,241
Western Interconnection	
Solar	875
Wind	2,250
Texas	
Solar	6,383
Wind	16

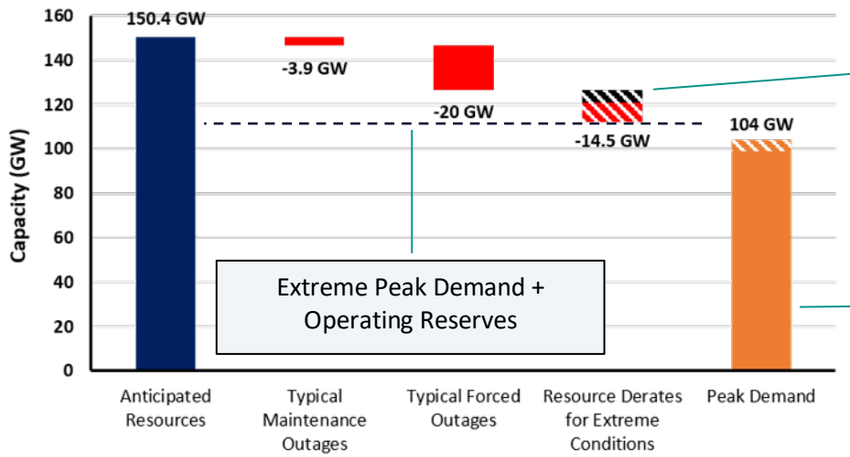
[10] For purposes of Table 1, Quebec is included within the Eastern Interconnection.

Risks and Trends Related to the Natural Gas System for the Upcoming Winter

The BPS added 9 GW of natural-gas-fired generation resources to its peak winter resource mix for the coming winter, highlighting the importance of expanded risk analysis relating to the growing natural gas fleet. The *2026–2027 WRA* includes a new analysis of the risk posed by constraints on the delivery of natural gas to natural-gas-fired generators within certain assessment areas for the upcoming winter. The analysis involved a five-year historical data review of the performance of natural-gas-only generators during the key winter events of those years.[11] The historical data stems from reporting to NERC's Generating Availability Data System (GADS).[12] Within the generator performance review, NERC assessed the hour of maximum loss of natural gas generating capacity in each assessment area during winter cold weather events in which GADS data reporters cited "lack of fuel" as the reason for the outage. There are two specific categories of causes that contribute to the overall "lack of fuel" reporting: One category is the physical failure of the fuel's delivery system due to an operational event on that system while the other is due to generator service contracting that allows for the curtailment of deliveries under certain conditions, or economic decisions impacting their ability to secure gas during peak conditions. The NERC analysis in this report does not distinguish between the two different sub-categories in the *2026–2027 WRA*. This specific fuel-related risk was then integrated into assessment area operational risk scenarios to support an evaluation of potential electricity supply resource availability during extreme conditions.

During extreme conditions, natural gas supplies to generators can be disrupted or curtailed due to natural gas infrastructure limitations, production declines from well-head freezing, and competing demand for natural gas with other users. Single-fueled natural gas (only) generators can be more susceptible to outage and derate because they cannot switch to alternate fuels. To account for natural gas-generator loss from fuel supply issues in winter operational risk analysis, NERC incorporated the historical highest hourly gas capacity outage, due to lack of fuel, into assessment areas' risk scenarios as part of the *Resource Derates for Extreme Conditions* (see **Figure 5**). In addition to availability issues with single-fuel natural-gas-fired generators, the broader category of *Resource Derates for Extreme Conditions* also includes non-fuel-related generator outages such as freezing issues and failures to start.

This operational risk analysis shows that the assessment area is expected to have sufficient resources to meet operating reserve requirements during a range of demand and resource scenarios, including extreme conditions that cause generator outages due to fuel issues.



Derates for Extreme Conditions (14.5 GW)
5.5 GW Historical maximum outages to natural gas only generators due to lack of fuel
9.0 GW Additional outages and derates from assessment area input data

Peak Demand Scenarios
104.0 GW Extreme peak demand similar to January 2025 winter storm
98.7 GW Normal winter peak demand **(after reduction from 8.4 GW DR)**

Figure 5: Operational Risk Analysis for MISO Including Natural Gas Fuel Availability Risk During Extreme Conditions

[11] *Natural-gas-only* refers to thermal generators that use natural gas only as their fuel source. Dual-fueled generators that are capable of switching to alternate or backup fuels were not included in the analysis.
[12] NERC's GADS maintains operating information on conventional generating units, wind plants, and solar plants. Through GADS, NERC collects information about the performance of electric generating equipment and supports equipment availability analyses.

The operational risk scenario is one of three inputs used by NERC to determine risk levels in seasonal reliability assessments such as the WRA. The operational risk scenario can also help BAs, RCs, and state and provincial energy officials evaluate expected electricity supplies, electricity demand, and operating reserve needs under normal peak demand conditions and more extreme scenarios that can occur when freezing temperatures affect demand, fuel supplies, and generator performance. The addition of a natural-gas-only generator component to the risk scenario is useful in evaluating potential electricity supply losses during extreme conditions that affect fuel delivery to generators because these resources are not capable of switching to alternate fuels.

Table 3 and **Table 4** contain the results of NERC's generator performance analysis, iterating the highest hourly outage rate of the natural-gas-only resources for each assessment area due to "lack of fuel." In some instances, system operators performed their own analysis of natural gas resources at risk of operational disruption due to a lack of fuel. In those cases, NERC deferred to the regionally performed analysis results and noted where such cases apply in the same tables. The results exclude any loss under 150 MW excluded from the list. MRO-SPP, MRO-MISO, and PJM were the three top assessment areas in terms of greatest hourly outages of single-fuel gas capacity due to fuel availability issues.

The findings somewhat correspond to the respective size of the single-fuel natural gas fleet that is expected to be available this coming winter season in those areas, but MRO-SPP's analysis of historical generator performance found the greatest fuel-related capacity losses, despite a fleet size that is less than half of MISO's and little more than a third of PJM's. Winter Storm Uri in 2021 proved to be the most impactful storm to MRO-SPP's single-fuel gas fleet.

Due to different GADS reporting practices in Canada and Mexico, NERC developed estimates of the MW value of a given area's single-fuel natural gas fleet that may be vulnerable to fuel supply disruptions through internal analysis and evaluation. NERC continues to refine the analytical approach for non-U.S. assessment areas through continued regional collaboration and outreach.

Table 3: Natural-Gas-Only Generator Performance Analysis

Assessment Area	5-Year Max Hourly Natural-Gas-Only Capacity Loss due to Lack of Fuel (MW)	Total Natural-Gas-Only Capacity for Winter 2026–2027 (MW)	% of Total Gas-Only Capacity at Risk
MRO-SPP*	8,000	23,936	33%
MRO-MISO	5,453	49,797	11%
PJM	4,213	60,726	7%
Texas RE-ERCOT	2,533	52,816	5%
NPCC-New York*	5,762	4,505	128%
WECC-California	669	35,759	2%
WECC-Northwest	174	7,350	2%
NPCC-New England*	5,052	8,450	60%

*Assessment Area submitted natural gas risk analysis showing the estimated value of natural gas resources potentially unavailable due to fuel supply constraints under extreme conditions and may, in some cases, include dual-fuel resources.

Table 4: Estimate of Canadian Natural-Gas-Only Generator Vulnerability

Assessment Area	Projected 5-Year Max Hourly Natural-Gas-Only Capacity Loss due to Lack of Fuel (MW)	Total Natural-Gas-Only Capacity for Winter 2026/2027 (MW)	% of Total Gas-Only Capacity at Risk
NPCC-Ontario*	500	8,376	6%

*Assessment Area submitted natural gas risk analysis showing the estimated value of natural gas resources potentially unavailable due to fuel supply constraints under extreme conditions and may, in some cases, include dual-fuel resources.

Lack of fuel can result from interruptions in gas supply and/or gas transportation. Pipeline-constrained regions of the North American BPS will continue to grapple with risk associated with limitations on natural gas transportation capacity for delivery to electricity customers. In recent years, key delivery points along the main natural gas pipeline systems into several regions have been scheduled at volumes beyond 100% of the operating capacity of those delivery points. The potential overreliance on interruptible transportation service agreements with pipeline operators can contribute to reliability concerns in some areas.

As natural gas supply interruptions, by whatever cause, remain a reliability concern for several assessment areas, the role of natural gas inventories in storage facilities across North America becomes increasingly critical. Last winter saw record weekly withdrawals of natural gas from storage the week ending January 30, 2026, and was credited with providing critical supply during stressed conditions, helping to alleviate the risk of BPS impacts from stretched natural gas supplies.

In the United States, natural gas inventories are heading into the winter withdrawal season with less in storage[13] (3,724 Bcf), as of the week ending October 23, than at the beginning of last winter (3,871 Bcf), but more than the five-year-average of inventory levels at the beginning of winter (3,686 Bcf). In Canada, the largest storage facility by working gas capacity is the Dawn Storage Hub in Ontario. Natural gas inventories at Dawn totaled 289 Bcf, up 8% year on year.[14]

U.S. Federal Power Act Emergency Authority

The U.S. DOE has increasingly exercised its authorities to maximize generator availability in response to emergencies resulting from electricity supply shortages. Many of the emergency orders issued by the DOE followed applications from utilities or system operators during extreme weather. DOE emergency orders maximize generation to prevent shortages by providing waivers for BPS generators to continue operating beyond air emissions limits, by authorizing grid operators to direct backup generators to come on-line thereby lowering grid demand. In addition, starting in 2025, the DOE issued emergency orders, pursuant to Section 202(c) of the Federal Power Act, requiring that six different power plants maintain operational availability. Thermal generators with diverse fuel sources can be an important electricity resource, especially during winter when solar photovoltaic (PV) and battery resources are less capable compared to summer months. The DOE has since renewed those emergency orders, extending availability requirements into December (see **Table 5**). These plants and units were not incorporated into the anticipated resources of their corresponding assessment areas for Winter 2026–2027 but may be called upon within the orders' time frames.

Table 5: Power Plants Impacted by Department of Energy 202(c) Orders in 2025 and 2026

Assessment Area	Plant Name	Nameplate Capacity (MW)	Winter Capacity (MW)	DOE 202(c) Order Expiration
MISO	J.H. Campbell	1,561	1,329	2/12/2027
MISO	F.B. Culley Generating Station	104	90	12/18/2026
MISO	Schahfer Generating Station	847	722	12/18/2026
PJM	Eddystone Generating Station	782	760	11/20/2026
WECC-NW	Centralia Generating Station	730	670	12/11/2026
WECC-RM	Craig Station	446	427	12/25/2026

[13] Weekly Natural Gas Storage Report - EIA

[14] Storage & Transportation Storage Reporting | Enbridge Gas

Risk Assessment Discussion

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. NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering three factors: 1) the on-peak reserve margins, 2) all-hours probability risk assessments, and 3) operational risk scenario (see **Table 6**). Other available risk information may also factor into a determination of winter risk. See Criteria in **Table 7**. Details for each assessment area are provided in the **Regional Assessments Dashboards**.

Table 6: Seasonal Risk Scenario

Assessment Area	On-Peak Reserve Margins	All-Hours Probabilistic	Operational Risk Scenario	2026-27 Risk Level	Prior Year Risk Level
MRO-MISO					
MRO-Manitoba					
MRO-SaskPower					
MRO-SPP					
NPCC-Maritimes[15]					
NPCC-New England					
NPCC-New York[16]					
NPCC-Ontario					
NPCC-Québec					
PJM					
SERC-C					
SERC-E					
SERC-FP					
SERC-SE					
Texas RE-ERCOT					
WECC-Alberta					
WECC-Basin					
WECC-British Columbia					
WECC-California					
WECC-Mexico					
WECC-Northwest					
WECC-Rocky Mountain					
WECC-Southwest					

Table 7: Seasonal Risk Assessment Summary

Category	Criteria
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels (RML) • Probabilistic indices exceed benchmarks (e.g., loss of load hours of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[a]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., loss of load hours above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[a] • 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)[b]
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[c]
Other Reliability Risks	Identified transmission constraints, fuel supply scenarios, or operating challenges that fall outside the risk criteria can affect parts or all of the assessment area.

Table Notes:
[a] **Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[b] **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 warranted.
[c] Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

[15] Maritimes uses a 20% RML established by regulators. However, it is not mandatory for resource adequacy.
[16] New York has an installed RML approved by NYSRC. For NERC's assessment, derated resource capacity is used rather than installed capacity. Therefore, NERC assessment uses the default RML of 15%.

On-Peak Reserve Margins and Operational Risk Scenario Analysis

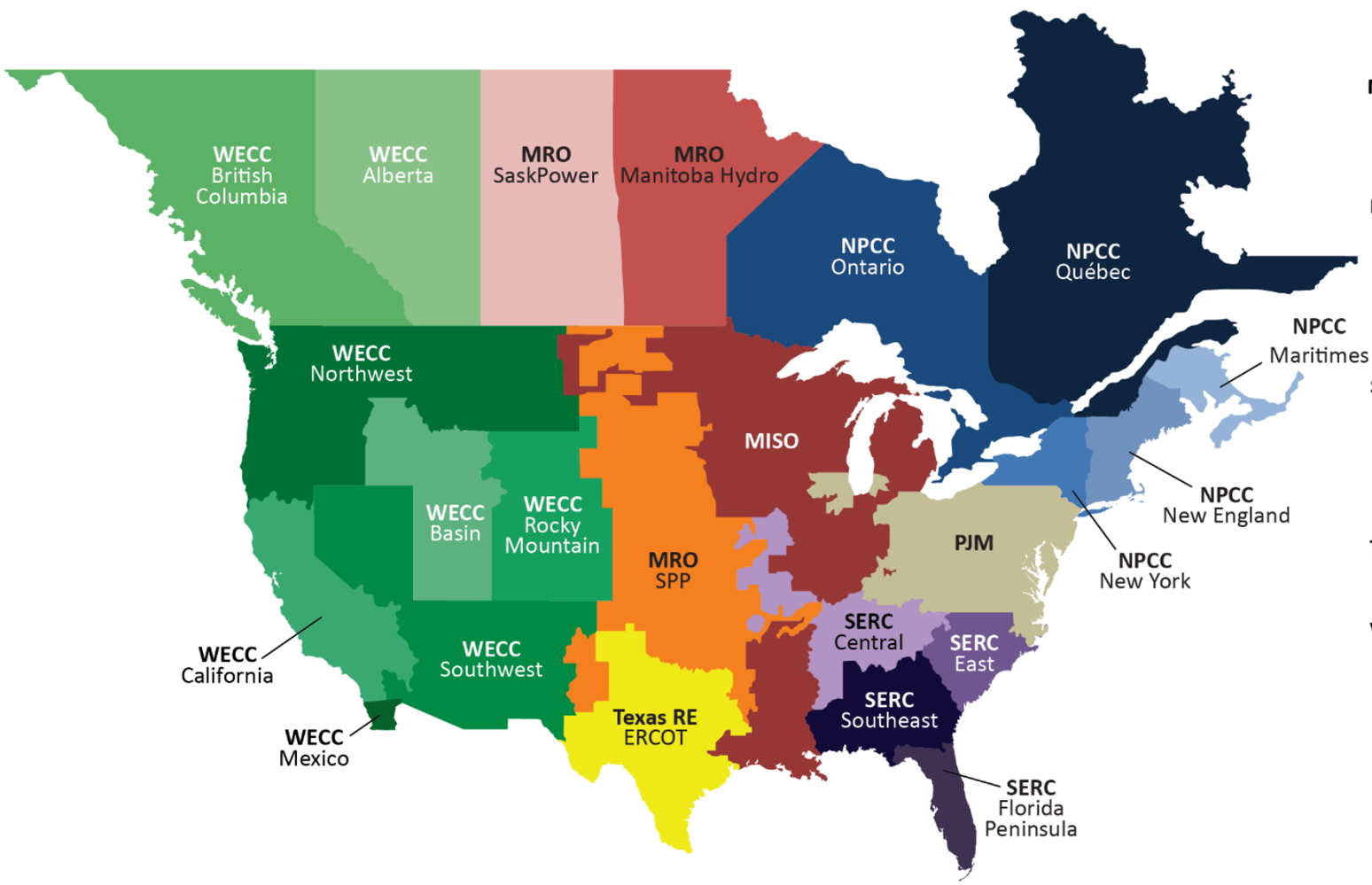
Risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. First, the Planning Reserve Margins analysis is highlighted on the right side of the dashboard pages. This analysis first highlights the Anticipated and Prospective Reserve Margins as well as the Reference Margin Level for this year's assessment compared to previous year's assessment. Second, the operational risk period scenario chart presents 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 period scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

All-Hours Probability Risk Assessment

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 the **All-Hours Probabilistic Risk Assessment** in **Table 8**. 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 EEA occurrence.

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. The dashboards cover 23 assessed areas as highlighted on the map below.



- MISO *(Midcontinent Independent System Operator)*
- PJM

MRO – Midwest Reliability Organization
- MRO-Manitoba Hydro
- MRO-SaskPower
- MRO-SPP *(Southwest Power Pool)*

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

SERC – SERC Reliability Corporation
- SERC-Central
- SERC-East
- SERC-Florida Peninsula
- SERC-Southeast

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT *(Electric Reliability Council of Texas)*

WECC – Western Electricity Coordinating Council
- WECC-Alberta
- WECC-Basin
- WECC-British Columbia
- WECC-California
- WECC-Mexico
- WECC-Northwest
- WECC-Rocky Mountain
- WECC-Southwest

Guidelines and definitions are in the **Data Concepts and Assumptions** table. Each dashboard consists of several elements that summarize the assessment:

- On-Peak Reserve Margin bar charts at the right of the dashboard show the ARM compared to an RML that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy.
- The risk period scenario analysis shown provide a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy.
  - For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the orange areas, top being cross hatched, of the stacked bar 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.
- An assessment of resources on-peak is also displayed at the left side of the dashboard.



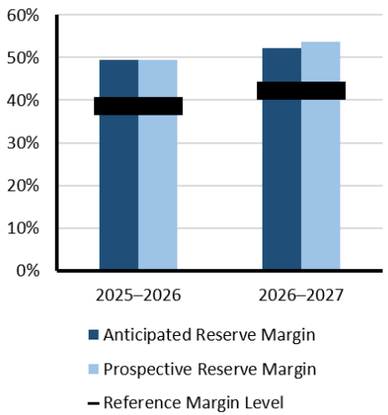
MRO-MISO

The Midcontinent Independent System Operator (MISO) is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 39 local BAs and over 500 market participants, serving approximately 45 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- MISO procured 4.2% more resources than the Planning Reserve Margin requirement based on the 1-day-in-10-years LOLE metric for resource adequacy needs through the planning year (PY) 2026–2027 planning reserve auction (PRA). A further 2.8 GW of capacity was offered but not procured through the PRA for the winter season. These resources may provide additional supply but are not committed.
- Several load pockets within the area rely on imported power during peak winter conditions. Under foreseeable system conditions, including abnormal system flows, specific generator outages, or restricted transfer capability, these pockets could face insufficient imports to maintain reliability.
- 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 the use of any number of measures, including load-modifying resources (LMR), non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement for the winter but may still offer into the energy markets, or internal transfers that exceed the sub-regional import/export constraint (SRIC/SREC) between the MISO North/Central and South regions. MISO continues to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet any needs for firm or non-firm transfers to address extreme system conditions.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, acknowledging that resource adequacy risk is not limited to the summer system peak season, MISO has filed and implemented changes to the resource adequacy construct to implement a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.

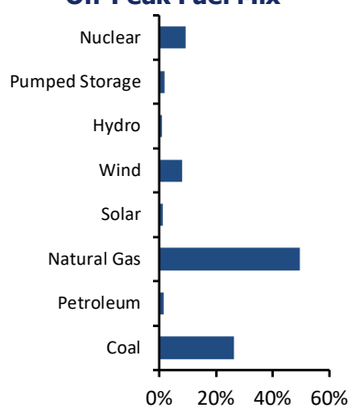
On-Peak Reserve Margin



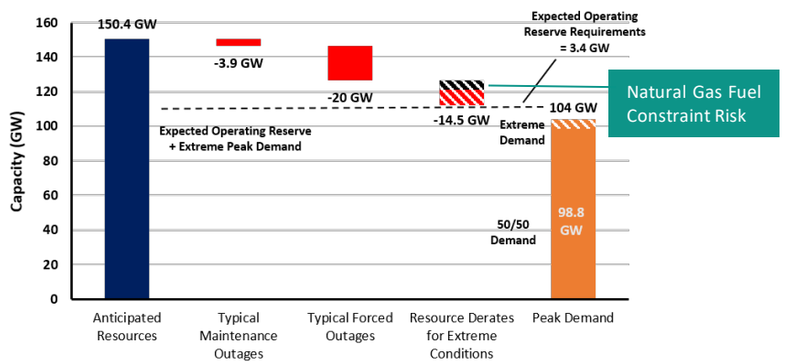
Risk Scenario Summary

Expected resources meet operating reserve requirements for normal conditions. Extreme conditions that cause above-normal peak demand, generator outages from weather and fuel issues, and low performance from LMRs (DR) can result in an energy emergency due to insufficient operating reserves. Low wind conditions will exacerbate shortfalls.

On-Peak Fuel Mix



2026–2027 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 data

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

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

Natural Gas Fuel Constraint Risk: Derates reflect highest reported hourly capacity of single-fuel gas generators on forced outage due to "lack of fuel" during recent winter storms, and amounted to 5,453 MW.



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 provides electricity to approximately 601,000 electric customers in Manitoba and to approximately 291,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 650 100 square kilometers (251,000 square miles). Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

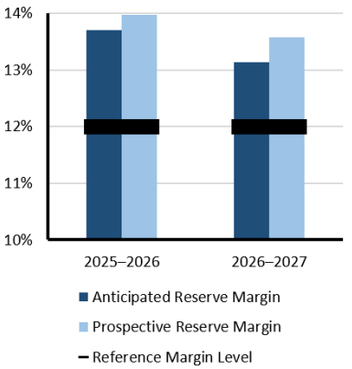
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Winter 2026–2027.
- Manitoba Hydro is experiencing above-average water supply conditions and expects to reliably supply its internal demand and export obligations, even if drought conditions develop in late 2026.
- The ARM for Winter 2026–2027 exceeds the 12% RML.

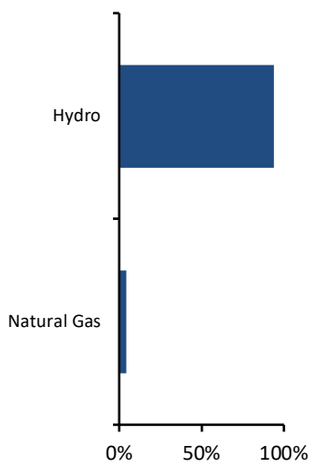
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

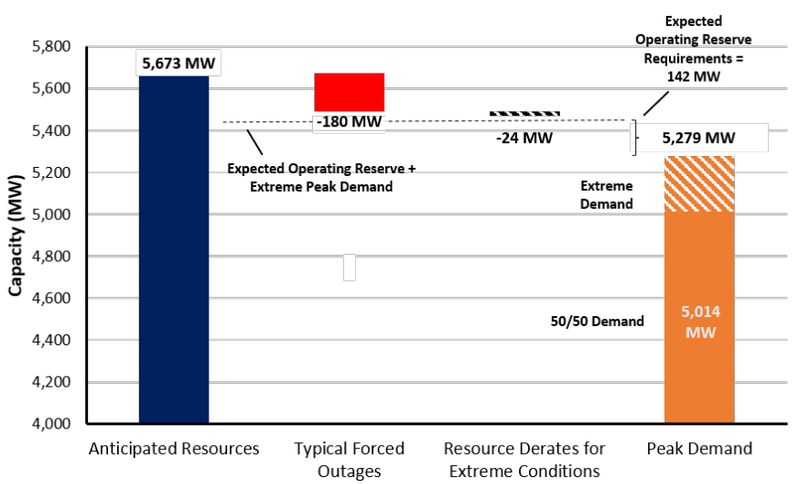
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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 scales additional load experienced during all-time peak actual versus forecasted load (January 2019)

Forced Outages: Accounts for average forced outages

Natural Gas Fuel Constraint Risk: Derates reflect NERC's estimate of the portion of MRO-Manitoba Hydro's single-fuel natural gas that may be vulnerable to fuel supply disruption based on historical data from neighboring areas, just 24 MW.



MRO-SaskPower

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

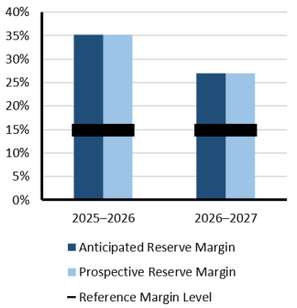
Highlights

- 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 conditions, SaskPower does not anticipate any reliability issues during the 2026–2027 Winter season.
- During extreme winter conditions, SaskPower might need to utilize maintenance rescheduling, short-term power transfers from neighboring utilities, and/or available demand response programs.

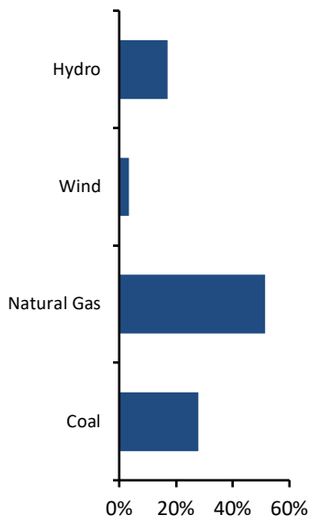
Risk Scenario Summary

Expected resources meet operating reserve requirements in assessed scenarios.

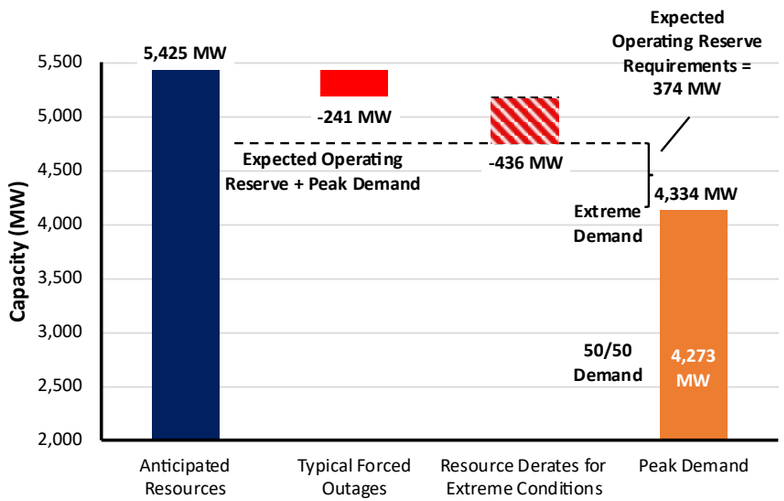
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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.

Forced Outages: Estimated using SaskPower forced outage model

Natural Gas Fuel Constraint Risk: Derates reflect NERC's estimate of the portion of MRO-SaskPower's single-fuel natural gas that may be vulnerable to fuel supply disruption based on historical data from neighboring areas, just 14 MW.



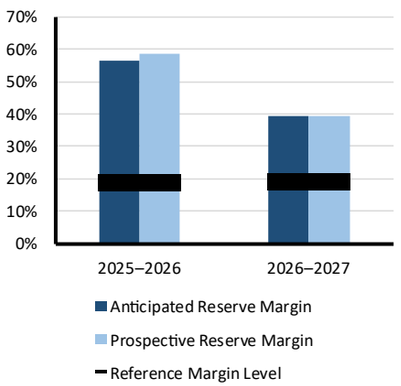
MRO-SPP

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

- Winter demand is forecast to increase approximately 3.7% from the prior WRA, reflecting continued load growth across the SPP footprint. This, along with capacity accounting changes implemented at SPP, has caused the ARM to decline since last winter.
- Resource adequacy risk remains low, with the LTRA ProbA reporting 0.00 LOLH and 0.00 MWh EUE for the 2026–2027 study year.
- Extreme winter weather remains the principal operational risk, with potential impacts from increased demand, generator outages, natural gas availability, and reduced renewable output.
- Import-dependent areas within SPP could experience reliability issues during periods of high demand or adverse weather conditions. Operating challenges are driven by increasing winter peak loads and the timing of transmission system upgrades to support continued integration of variable energy resources and inverter-based resources.

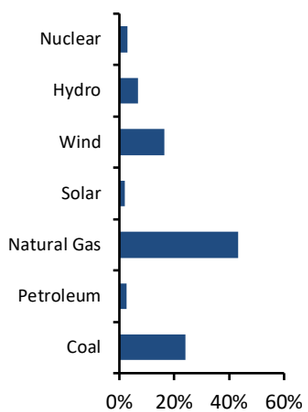
On-Peak Reserve Margin



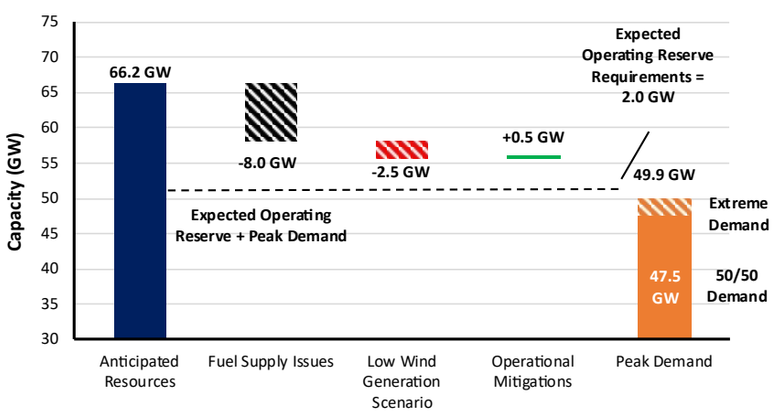
Risk Scenario Summary

Expected resources meet operating reserve requirements for normal and more extreme peak demand. Extreme conditions that cause above-normal peak demand and generator outages from extreme weather and fuel issues can result in an energy emergency due to insufficient operating reserves. Low wind conditions will exacerbate shortfalls during these periods.

On-Peak Fuel Mix



2026–2027 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 for maintenance outages, forced outages, and performance in extreme weather based on historical data

Fuel Supply Issues: Derates reflect regional analysis of natural gas resources vulnerable to outage or derate due to fuel supply challenges, 8,000 MW.

Low Wind: 2.5 GW of wind potentially off-line when temperatures fall below their cold weather performance package



NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 150,000 square kilometers (58,000 square miles) with a total population of 1.9 million.

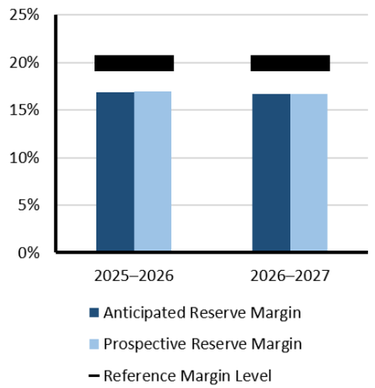
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place.
- The Maritimes has long-term energy contracts and can purchase energy day-ahead and in real time as required.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.

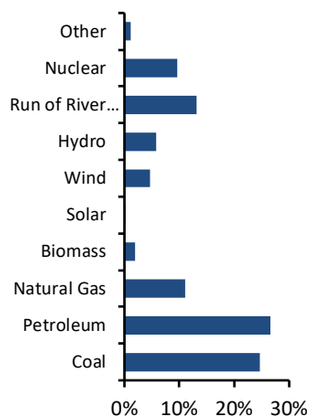
Risk Scenario Summary

Expected resources do not meet operating reserve requirements for normal peak demand. More extreme demand or generator outages would require operators to procure additional resources or employ operating mitigations (e.g., DR, non-firm transfers, and appeals for energy conservation).

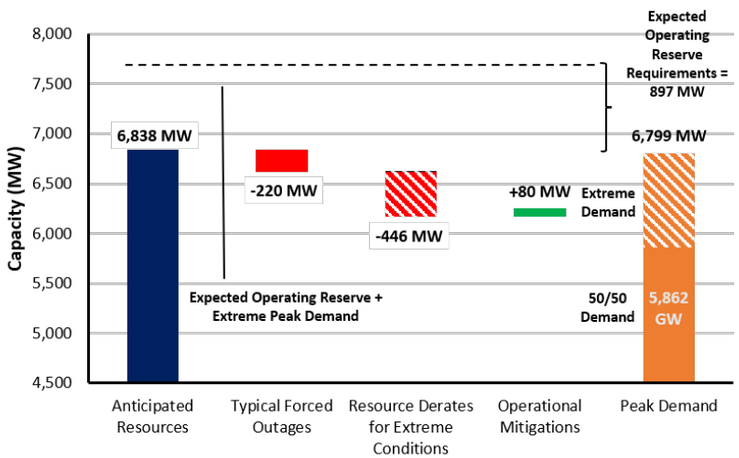
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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 LTRA for the 2026–2027 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2024)

Forced Outages: Based on historical operating experience

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

Natural Gas Fuel Constraint Risk: Derates reflect NERC's estimate of the portion of NPCC-Maritimes' single-fuel natural gas that may be vulnerable to fuel supply disruption based on historical data from neighboring areas, just 4 MW.

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



NPCC-New England

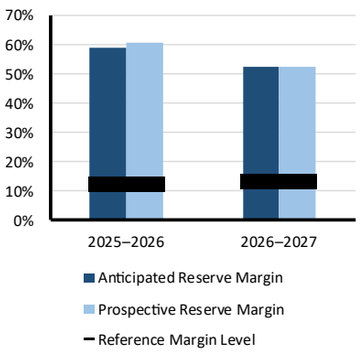
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New 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 transmission and resource adequacy requirements this 2026–2027 winter operating period. ISO-NE also closely monitors the region's energy adequacy through seasonal and weekly assessments using its Probabilistic Energy Assessment Tool (PEAT). Probabilistic energy assessments for the 2026–2027 Winter season are being performed and are expected to show minimal energy shortfall risk.
- ISO-NE expects to have sufficient capacity resources to meet the 2026–2027 50/50 and 90/10 winter peak net internal demand forecast of 20,099 MW and 21,073 MW, respectively, for the weeks beginning January 9, January 16, and January 23.
- ISO-NE and its stakeholders will continue to utilize the Regional Energy Shortfall Threshold (REST) as an effort to quantify the tolerable risk of energy shortfall during extreme events. Introduced prior to Winter 2025–2026, the REST is applicable to seasonal outlooks and longer-term (i.e., 5- and 10-year horizon). The REST thresholds are 3.0% normalized expected unserved energy over 72-hour periods and 18.0 hours over 21-day periods within the 0.25% highest risk scenarios. ISO-NE does not anticipate exceeding the REST criteria for Winter 2026–2027.

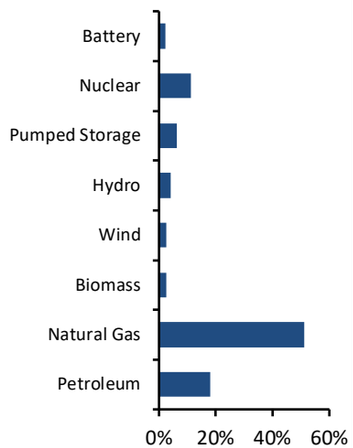
On-Peak Reserve Margin



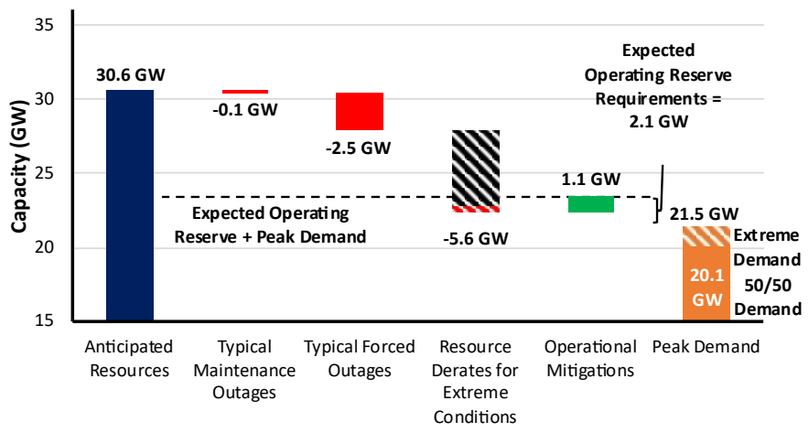
Risk Scenario Summary

Expected resources meet operating reserve requirements for normal peak demand. However, system operators in NPCC-Maritimes have access to additional energy transfers with neighbors through short term firm commitments under most conditions. Extreme demand or generator outages could require operators to employ operating mitigations (e.g., DR, non-firm transfers, and appeals for energy conservation) and could result in energy emergencies.

On-Peak Fuel Mix



2026–2027 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

Maintenance Outages: Based on historical weekly averages

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

Extreme Derates: ISO-NE assumes a derate of 500 MW to account for resources that "fail to start" during extreme winter conditions.

Natural Gas Fuel Constraint Risk: ISO-NE determines a "Gas at Risk" value, in megawatts, that corresponds to the systems internal demand and is how the region estimates generating capacity that could become unavailable because of limitations in natural gas delivery during the winter operating period, which amounted to 5,052 MW.

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 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 2026–2027 IRM at 24.5%.

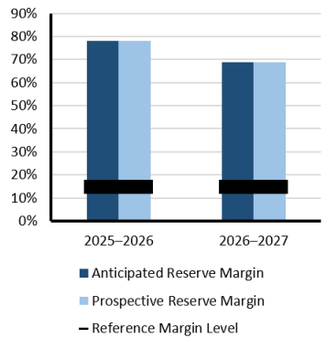
Highlights

- New York is presently a summer-peaking area, and no emerging reliability issues are anticipated during the 2026–2027 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, LOLH, or EUE risks were indicated over the December–February winter period for all the scenarios modeled.

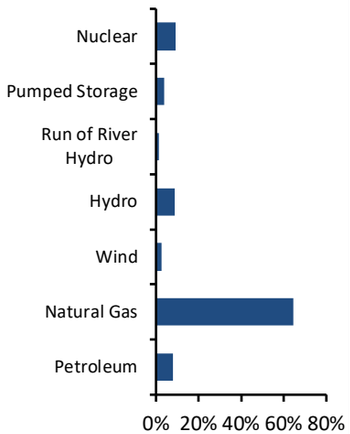
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

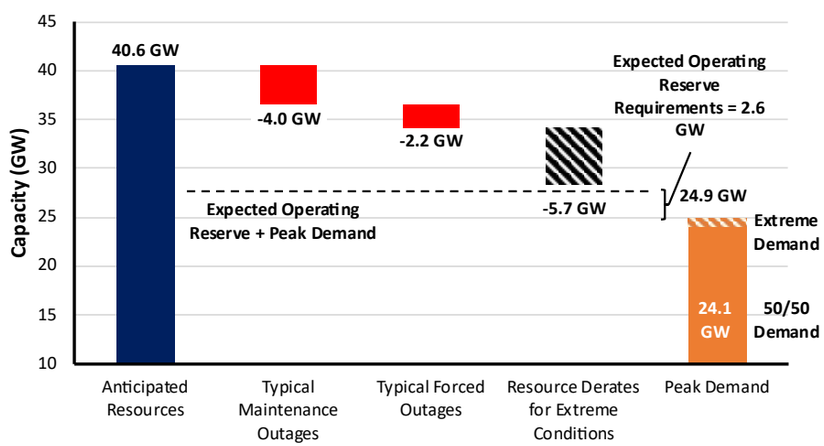
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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

Maintenance Outages: Based on planned scheduled maintenance

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

Natural Gas Fuel Constraint Risk: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather as determined by NYISO. Based on the analysis, approximately 5,672 MW of gas generation with non-firm fuel supplies could be unavailable.



NPCC-Ontario

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

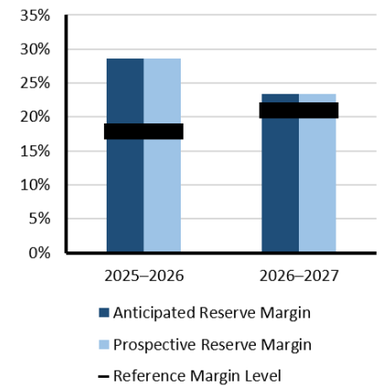
Highlights

- Ontario is well prepared for upcoming season, and the IESO expects that the electric system will remain reliable. Operators and forecasters coordinate closely with neighboring jurisdictions to manage any extreme weather events.
- All Pickering B Nuclear Generating Station units have been taken off-line, and major refurbishment work is expected to commence, pending regulatory approvals. This outage has been anticipated and planned for by the IESO for several years and has been incorporated into its long-term system planning and reliability assessments. The Pickering B planned outage is the main driver for lower capacity (and lower ARMs) in the assessment area compared to last winter.

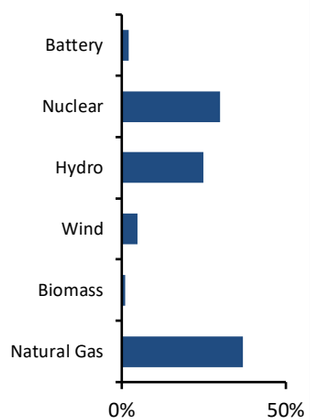
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

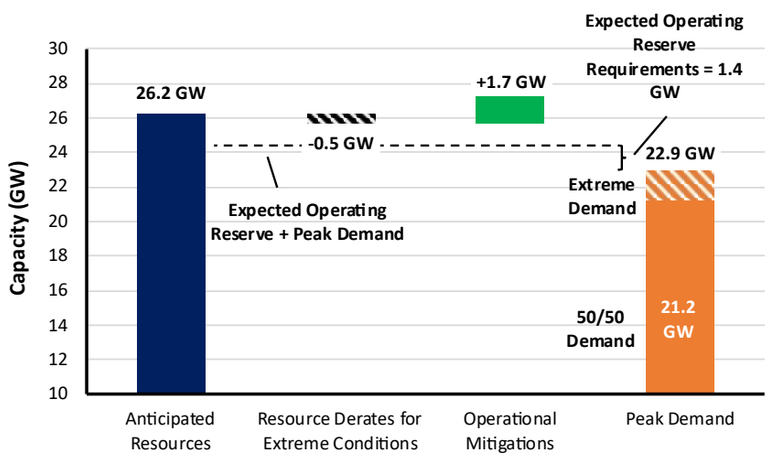
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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

Extreme Derates: Generation unavailability in an extreme event using temperature derates

Natural Gas Fuel Constraint Risk: In IESO's low likelihood resource case, the system operated assumed a 500 MW reduction in gas-fired generation available due to fuel-related constraints.

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 nearly 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 predominantly 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.

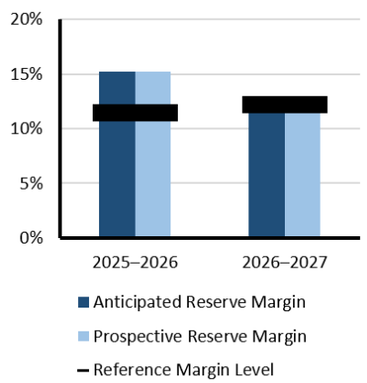
Highlights

- NPCC-Québec has smaller net margins than last year, driven principally by a decrease in certain generation capacity for the upcoming winter (-1,532 MW) that is mainly the result of an increase in planned/known outages, which is partially offset by a decrease in net firm exports (-495 MW).
- NPCC-Québec projects anticipated margins slightly above its reference reserve requirements. Operating mitigations (i.e., imports from neighboring areas, reductions in reserves) could be required for severe winter load and outage conditions.
- No hydropower performance issues are expected during extreme cold because of adequate design criteria for cold weather.
- No fuel supply or transportation issues are anticipated for the upcoming winter season.

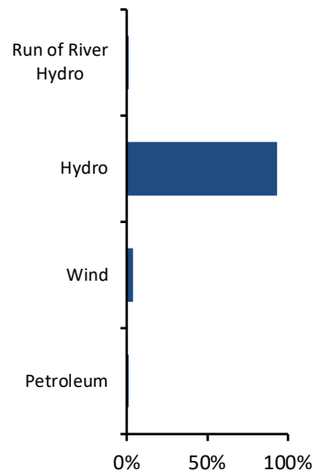
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under extreme demand scenario.

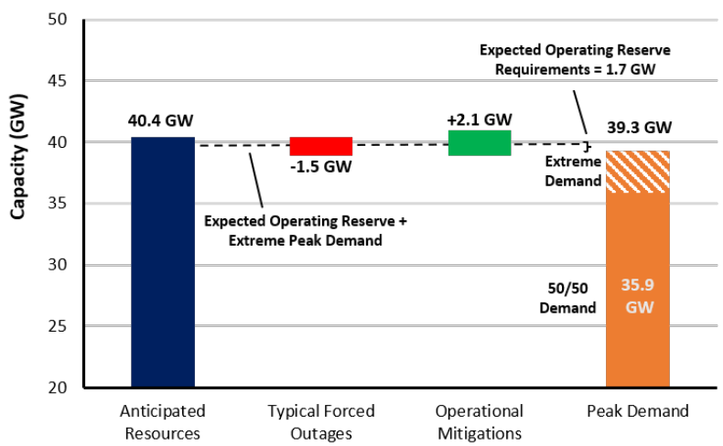
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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 already derated in existing-certain capacity calculation; wind capacity is 64% derated

Forced Outages: Scenario involving 1,500 MW in unplanned outages

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 serves 67 million customers and covers 368,906 square miles. PJM is a BA, PC, Transmission Operator and Planner, Resource Planner, Interchange Authority, Transmission Service Provider, and RC.

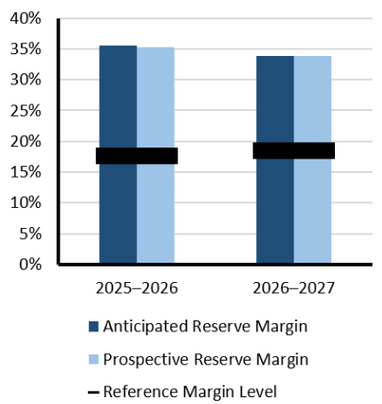
Highlights

- Under normal winter conditions, PJM is expecting little capacity adequacy risk during Winter 2026–2027 and expects around 33% installed reserves, which is above the target IRM of 18.6% necessary to meet the 1-day-in-10 years criterion.
- There are no resource adequacy challenges from either an energy or capacity perspective, but PJM is projecting tightening reserves in the upcoming years.
- Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand.

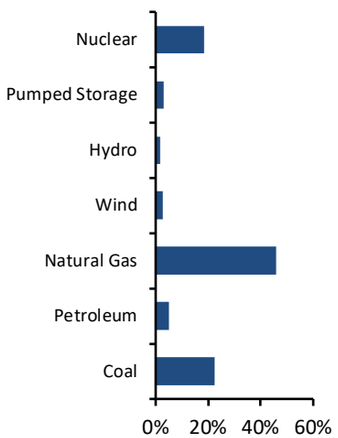
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. During extreme winter conditions that cause above-normal demand and high generator outages, PJM is likely to employ EEAs to access DR and other load reductions from large load facilities with backup generation. PJM may request a DOE 202c waiver that would grant PJM operators added flexibility by providing temporary relief from environmental permit restrictions and authorization to direct large load customers to switch to backup generation resources, if necessary.

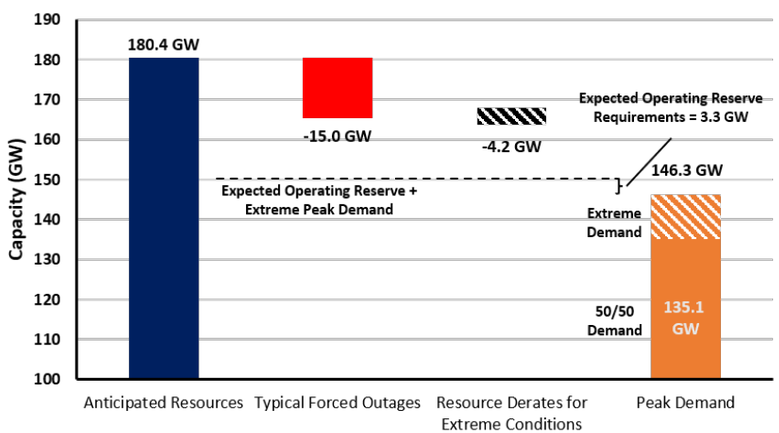
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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

Forced Outages: Based on historical data and trending

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

Natural Gas Guel Constraint Risk: Derates reflect highest reported hourly capacity of single-fuel gas generators on forced outage due to "lack of fuel" during recent winter storms, 4,213 MW.



SERC-Central

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

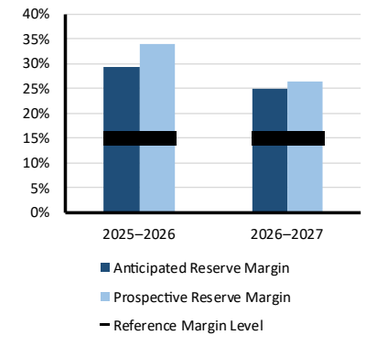
Highlights

- 2026–2027 ARM decline is primarily driven by increased demand and reduced firm imports, while adjusted anticipated capacity remains relatively stable year over year.
- Extreme Winter Conditions: Severe winter conditions could create periods of resource adequacy stress due to elevated demand and reduced resource availability.
- Operational Mitigation: Conservative operating procedures and demand-side measures provide significant mitigation during extreme conditions and support the ability to maintain required operating reserves.
- Fuel Availability: Firm natural-gas arrangements, dual-fuel capability, and available coal and oil inventories provide additional resilience during extreme winter conditions.
- Winter Preparedness: Resources and transmission are expected to be adequate under normal winter conditions, with continued monitoring of weather, demand, generation, fuel, and transmission conditions and increased operator attention as conditions warrant.

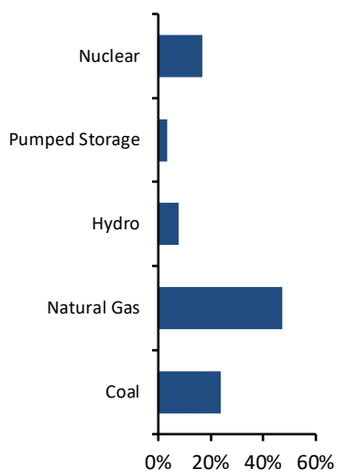
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios.

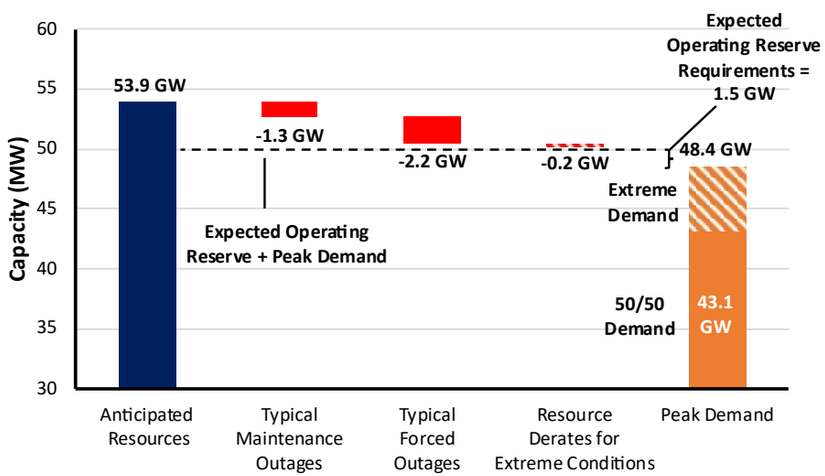
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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

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

Forced Outages: Includes any weighted average forced-outage rates on-peak that are not factored into the anticipated resources calculation

Extreme Derates: The scenario represents a stressed winter condition in which demand is elevated across the region and generating resources may experience increased forced outages or weather-related derates.



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.

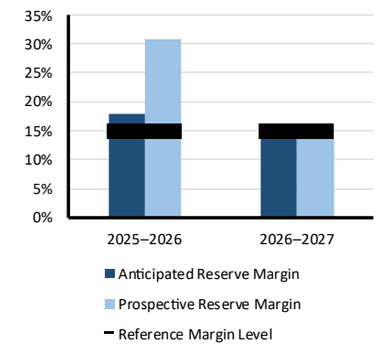
Highlights

- 2026–2027 ARM decline is primarily driven by increased demand, while adjusted anticipated capacity remains relatively stable year over year.
- The ProbA indicates limited loss-of-load risk during Winter 2026–2027, concentrated primarily in January during early-morning hours. Severe winter conditions may further increase demand, reduce generation availability, and limit imports, creating additional resource adequacy challenges during periods of high demand and reduce resource availability.
- Existing operating procedures, demand-side measures, generation availability measures, and coordination with neighboring entities provide mitigation to manage resource adequacy challenges during stressed winter conditions.
- Continued residential, commercial, industrial, and large load growth is increasing winter peak demand in portions of the subregion, contributing to greater sensitivity during winter morning peak conditions.
- No significant fuel or transmission constraints are anticipated for the upcoming winter. Existing resources, winter preparedness activities, operating procedures, and coordination provide mitigation for identified operational risks.

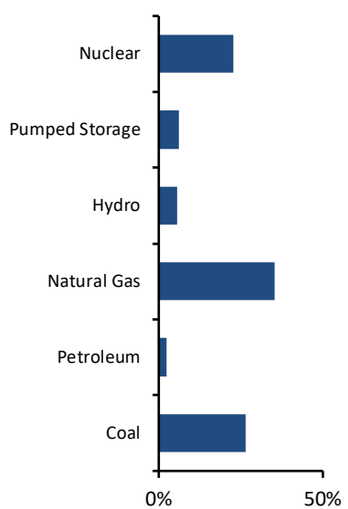
Risk Scenario Summary

Expected resources meet operating reserve requirements for normal peak demand. Extreme conditions that cause above-normal peak demand and generator outages from weather and fuel issues can result in an energy emergency due to insufficient operating reserves.

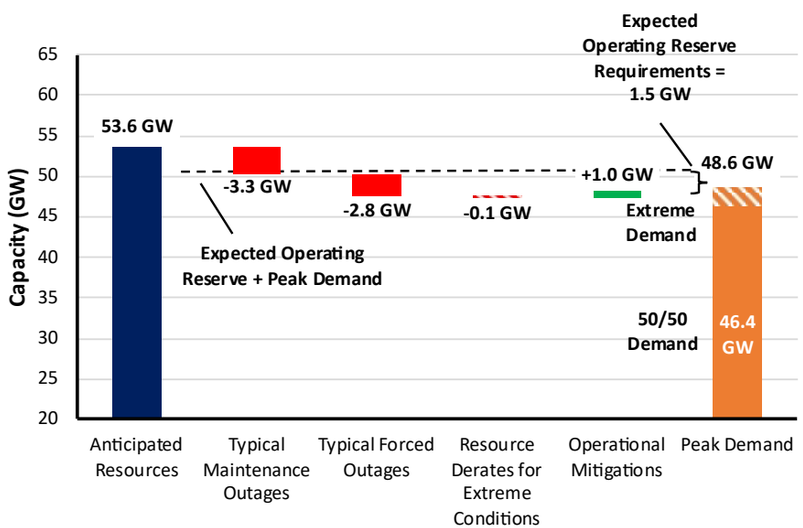
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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

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

Forced Outages: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation

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

Operational Mitigations: A total of 1.0 GW based on operational/emergency procedures



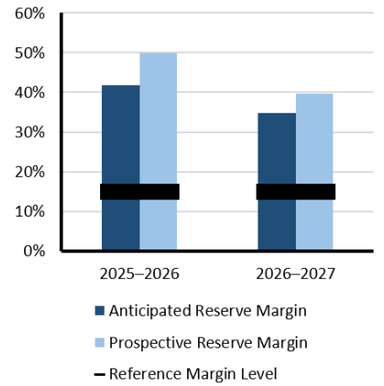
SERC-Florida Peninsula

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

- Over 30% ARM supports adequate capacity for the 2026–2027 Winter season.
- Lessons from the 2025–2026 Winter resulted in enhanced capacity monitoring, coordination, and emergency preparedness in system operations.
- No significant transmission outages or transfer limitations are anticipated for the upcoming winter.
- Extreme winter conditions could increase demand or reduce resource availability; normal preparedness and operating practices provide mitigation.

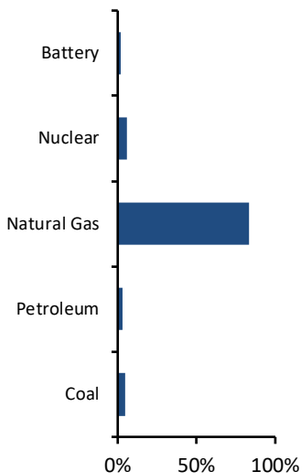
On-Peak Reserve Margin



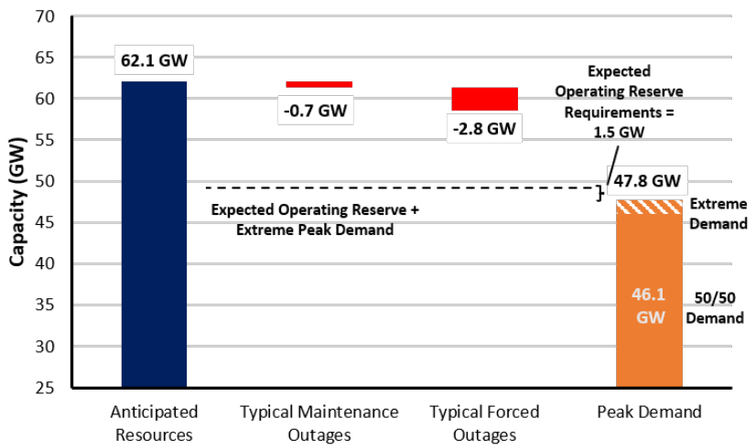
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios.

On-Peak Fuel Mix



2026–2027 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

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

Forced Outages: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation.



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.

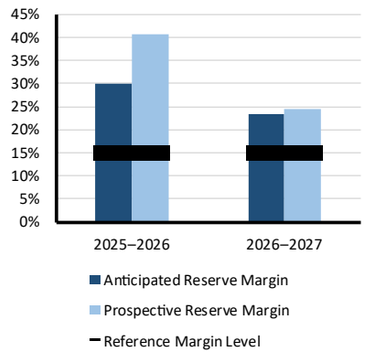
Highlights

- 2026–2027 ARM decline is driven by increased demand and higher firm export commitments, while accounting for updated solar capacity.
- Natural Gas Deliverability: Natural gas transportation and operating requirements may constrain natural-gas-fired generation during periods of high demand or extreme winter conditions; firm transportation, dual-fuel capability, and fuel inventories provide mitigation.
- Large Load Growth: Continued large load growth is increasing demand and may reduce transmission and outage flexibility under certain conditions.
- Extreme Winter Conditions: Extreme or prolonged winter weather could increase resource and fuel constraints when high demand coincides with generation outages or derates.
- Winter Preparedness: No significant resource adequacy or transmission concerns are expected under normal winter conditions; continued monitoring, established operating procedures, outage coordination, and neighboring coordination provide mitigation during stressed conditions.

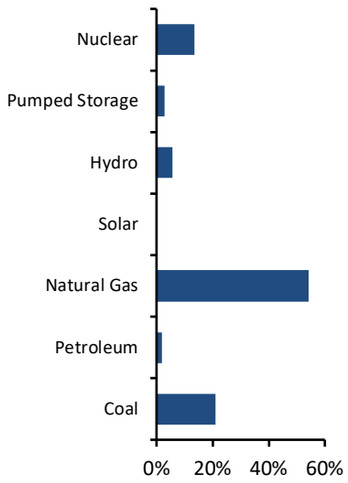
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

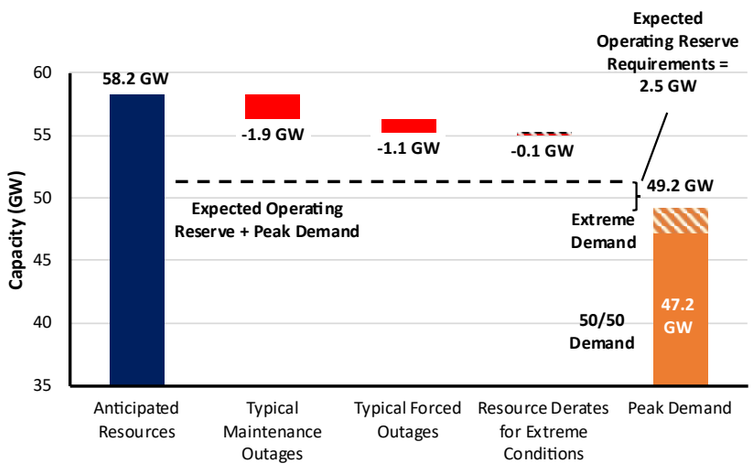
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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

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

Forced Outages: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Maximum historical generation outages



Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 55,000 miles of transmission lines, has over 1,460 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.

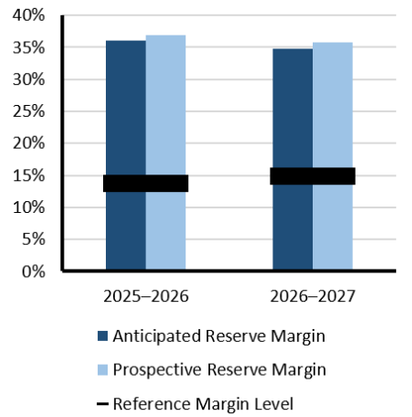
Highlights

- Given an ARM of 34.8% and RML of 15%, ERCOT expects to have sufficient operating reserves for the winter peak load hour (hour ending 8:00 a.m.) given expected normal system conditions.
- There is EEA risk in the early morning and evening hours due to elevated loads during these periods as well as low to no solar generation.
- ERCOT defines low EEA risk as less than 10%, and ERCOT's probabilistic risk assessment indicates the hour with the highest EEA declaration risk is the forecasted winter peak load hour with an EEA probability of 2.7% with the probability of controlled load shed being 2.1%.
- Robust growth in battery storage resources added to the Texas RE-ERCOT region mitigates EEA risks; however, maintaining sufficient battery state of charge (SOC) is challenging for extended periods of high loads.
- In 2026, ERCOT identified a new large computational loads (LCL) operational risk. When LCLs are in similar areas of the grid and do not have the ability to ride through a voltage excursion, there is an increased risk that a large amount of MWs could be lost because of a fault on the system.
- ERCOT has instituted LCL voltage ride-through requirements that became effective on August 1, 2026, for new LCLs.
- ERCOT does not expect any significant fuel supply issues for the winter.
- Facilities must complete emergency preparation measures and submit their declarations of weather preparedness (DoWP) by December 1, 2026.

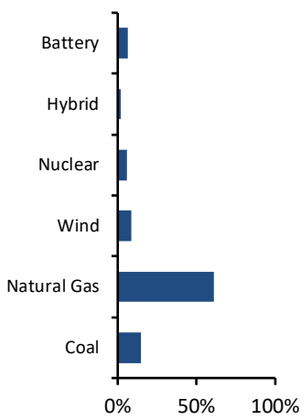
Risk Scenario Summary

Expected resources meet operating reserve requirements for normal peak demand. Extreme conditions that cause above-normal peak demand and generator outages from weather and fuel issues can result in an energy emergency due to insufficient operating reserves.

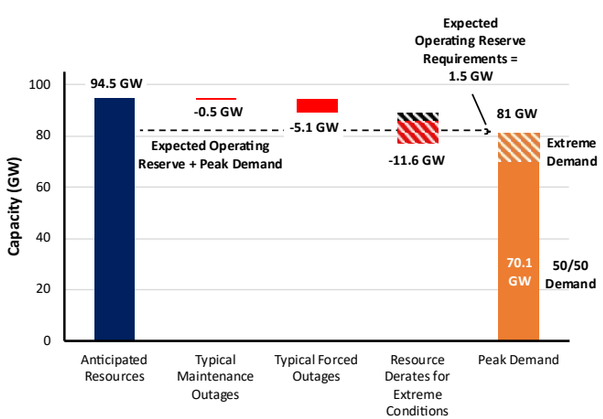
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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 and 50th percentile values from ERCOT's Probabilistic Reserve Risk Model (PRRM) simulated load outcome distribution for hour ending 8:00 a.m.

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

Forced Outages: ERCOT uses 2021 Winter Storm Uri as the basis for winter probabilistic risk assessment and accounts for estimated weather-related forced outage improvements.

Extreme Derates: The difference between the 100th and 50th percentile values from the PRRM distribution for hour ending 8:00 a.m. The simulation uses historical ERCOT Outage Scheduler data for the last three Januarys.

Natural Gas Fuel Constraint Risk: Reflects highest reported hourly capacity of single-fuel gas generators on forced outage due to "lack of fuel" during recent winter storms, 2,533 MW.



WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity, serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and BC in Canada and the northern portion of Baja California in Mexico as well as all or portions of 14 western U.S. states in between. WECC's 329 members include 36 BAs, representing a wide spectrum of organizations with an interest in the BES.

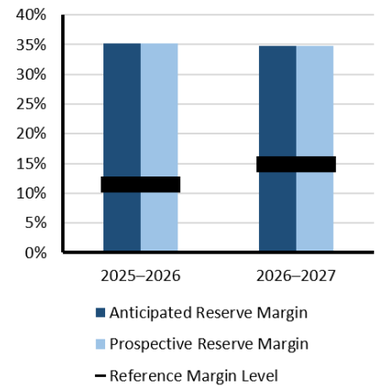
Highlights

- Operators in the assessment area can meet operating reserve requirements for the range of assessed scenarios this winter. This includes the extreme winter peak of 13,040 MW, with extreme forced outage and resource derates. Recent retirement of WECC's regional standards for contingency reserves has lowered Alberta's reserve requirement from 745 MW to 254 MW.
- Peak demand is forecast to increase slightly (+0.4%) from last winter, while installed capacity has decreased by 1.6% due in part to lower wind availability driven by updated shapes, and higher potential derates for gas units.
- New resource additions for the winter include energy storage, wind, solar, and a natural gas unit scheduled to come on-line December 2026. These additions are expected to connect prior to peak winter conditions and make up for reduced availability from existing capacity.

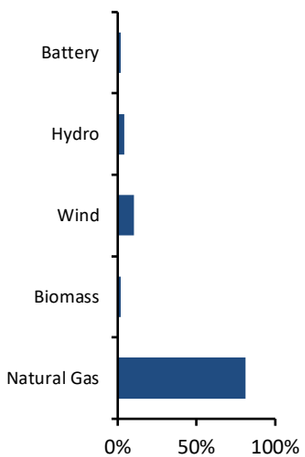
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and resource outage scenario. Extreme demand combined and outages could require operators to obtain non-firm imports and employ operating mitigations to meet reserves.

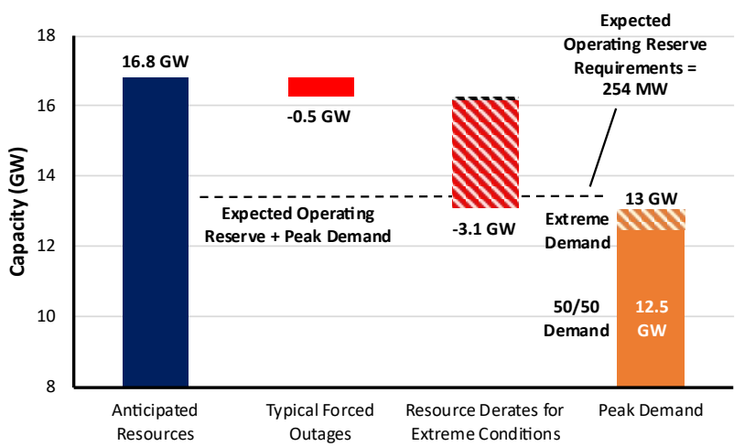
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Thermal, wind, and solar are incremental reductions based on the hourly availability curves' probability distribution's 10th percentile "extreme scenario"

Natural Gas Fuel Constraint Risk: Derates also reflect NERC's estimate of the portion of WECC-Alberta's single-fuel natural gas that may be vulnerable to fuel supply disruption based on historical data from neighboring areas, just 74 MW.



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 Bulk Electric System (BES) reliability in the Western Interconnection. WECC's 329 members include 36 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

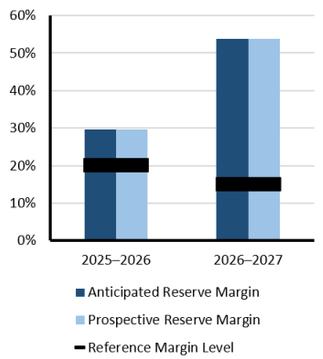
Highlights

- Operators in the assessment area can meet operating reserve requirements for the range of assessed scenarios this winter. This includes the extreme winter peak demand of 11,926 MW, with extreme forced outages and resource derates.
- Recent retirement of WECC's regional standards for contingency reserves has lowered reserve requirements in the assessment area from 635 MW to 284 MW.
- Total internal demand is expected to increase 3.5% from last winter, while existing-certain capacity increased by 15.4%, including more than 500 MW of battery storage and 500 MW of solar. Some coal unit retirements have been delayed, where Basin entities own partial shares. The Naughton gas conversion came on-line as expected.
- More than 60% of the capacity of Tier 1 projects are verified operational.

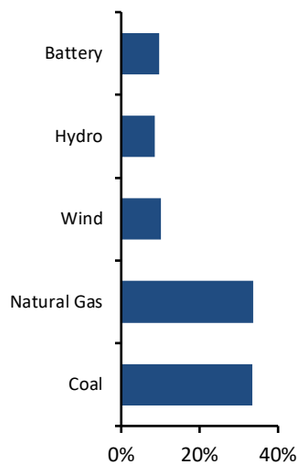
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

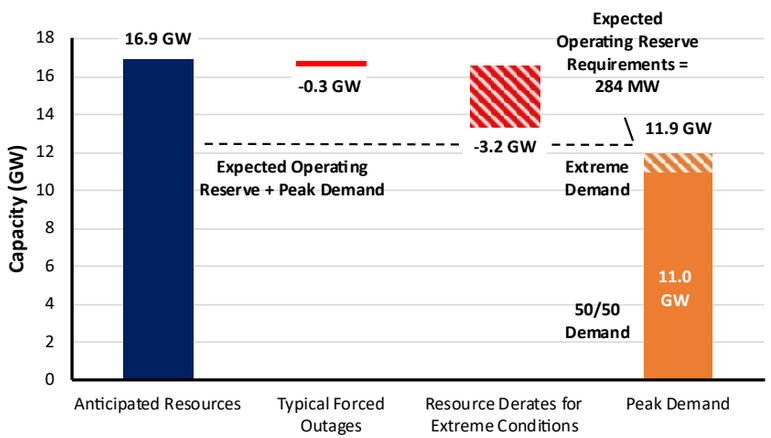
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 36 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

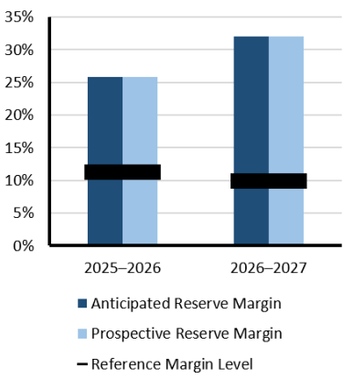
Highlights

- Operators in the assessment area can meet operating reserve requirements for the range of assessed scenarios this winter including the extreme winter peak demand of 13,364 MW, with extreme forced outages and resource derates.
- Recent retirement of WECC's regional standards for contingency reserves has lowered British Columbia's reserve requirement from 716 MW to 236 MW.
- Total internal demand is expected to increase 1.9% from last winter, with existing-certain capacity rising by the 6%.
- The expected increase in available generation on the winter peak hour is driven by a modeling improvement that better captures the availability of large hydro reservoirs.

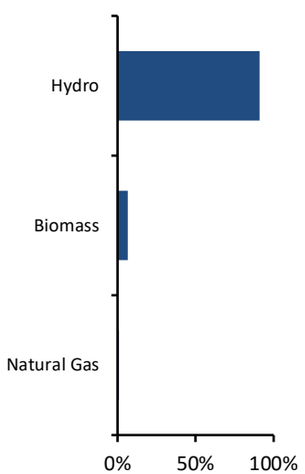
Risk Scenario Summary

Expected resources meet operating reserves for assessed scenarios.

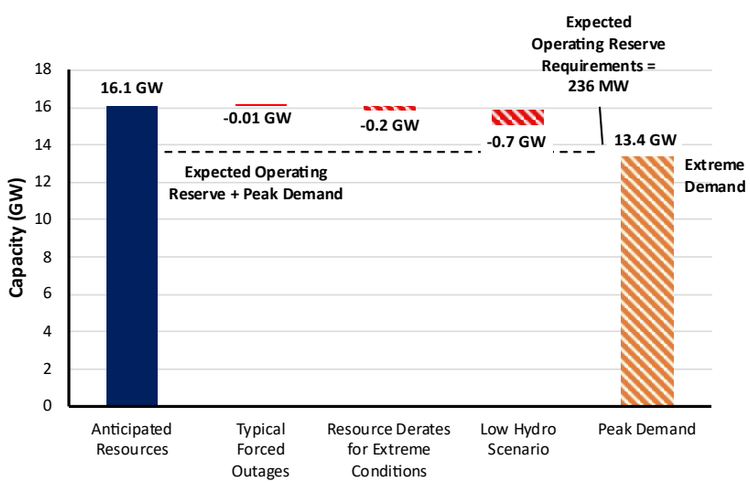
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

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, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 36 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

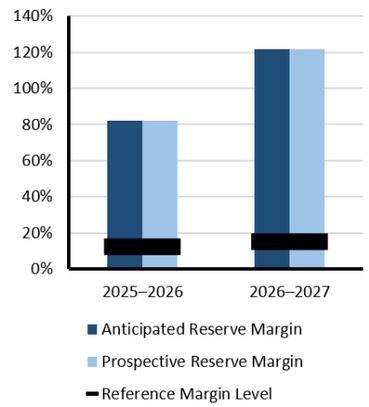
Highlights

- Operators in the assessment area can meet operating reserve requirements for the range of assessed scenarios this winter including the extreme winter peak demand of 35,766 MW, with extreme forced outages and resource derates.
- New wind and battery resources contribute to an overall increase in available reserves for California this winter with approximately 5 GW of battery storage, including the 500 MW Bellefield battery project, added. Phase 2 of this project is scheduled to come on-line this winter.
- Over 1 GW of Tier 1 projects are expected to be operational before the winter peak. 45% of the Tier 1 capacity is verified operational; even without the Tier 1 additions, California has high reserve margins projected for the winter.

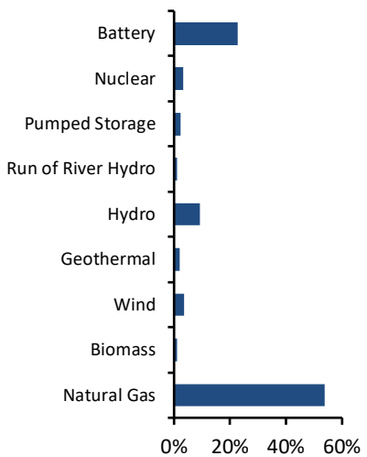
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios.

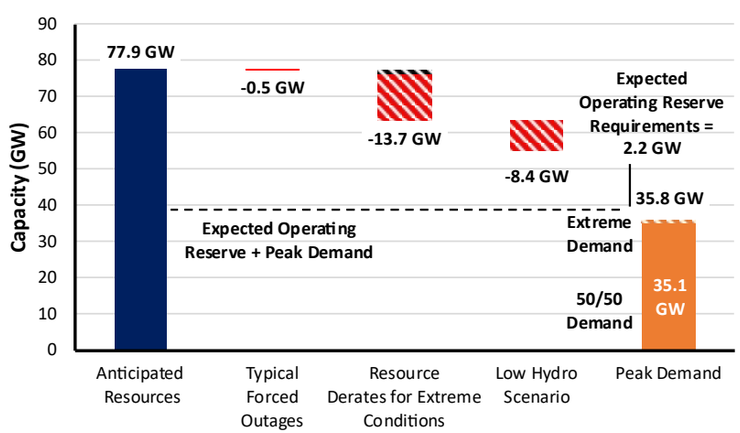
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: WECC calculates the 10th and 90th percentiles to represent derates for extreme conditions based on historical data from 43 weather years to calculate fluctuations in demand and availability of variable resources.

Natural Gas Fuel Constraint Risk: In addition, extreme derates also reflect highest reported hourly capacity of single-fuel gas generators on forced outage due to "lack of fuel" during recent winter storms, 669 MW.



WECC-Mexico

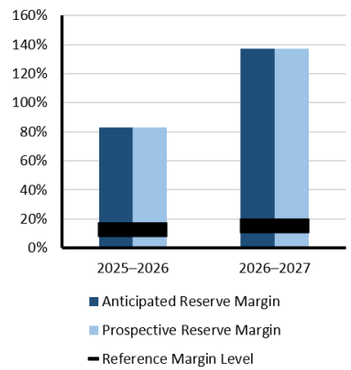
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 36 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.

- Operators in the assessment area can meet operating reserve requirements for the range of assessed scenarios this winter including extreme winter peak demand of 2,011 MW, with extreme forced outages and resource derates.
- New natural-gas-fired generators have increased capacity in the assessment area since last winter, while there has been little change to forecasted peak demand. Reserve margins have increased accordingly.

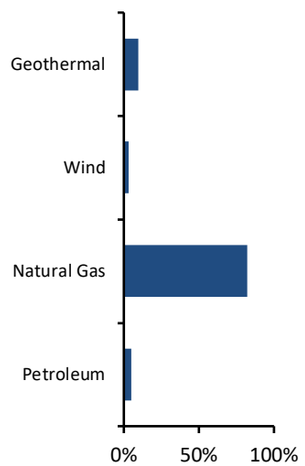
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios.

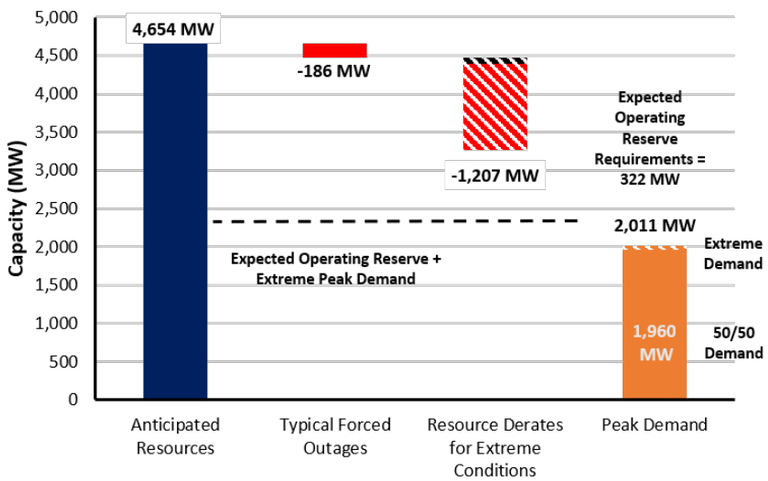
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 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

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Thermal, wind, and solar are incremental reductions based on the hourly availability curves' probability distribution's 10th percentile "extreme scenario."

Natural Gas Fuel Constraint Risk: Derates reflect NERC's estimate of the portion of WECC-Mexico's single-fuel natural gas that may be vulnerable to fuel supply disruption based on historical data from neighboring areas, 74 MW.



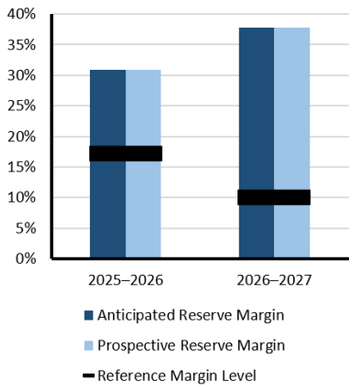
WECC-Northwest

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 36 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- Operators in the assessment area can meet operating reserve requirements for the range of assessed scenarios this winter including the extreme winter peak demand of 37,312 MW, with extreme forced outages and resource derates.
- Recent retirement of WECC's regional standards for contingency reserves has lowered reserve requirements in the assessment area from 2,014 MW to 686 MW.
- Total internal demand is expected to increase 1.1% from last winter, with existing certain capacity rising by almost 18%. Several large battery projects have come on-line and while 15% of Tier 1 MW availability has been verified on-line.
- On top of resource additions, the expected wind contribution increased from 9% to about 28%, with 7% modeled under extreme derate conditions resulting in the area having higher reserve margins compared to last winter

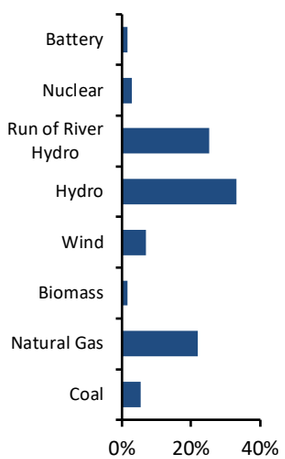
On-Peak Reserve Margin



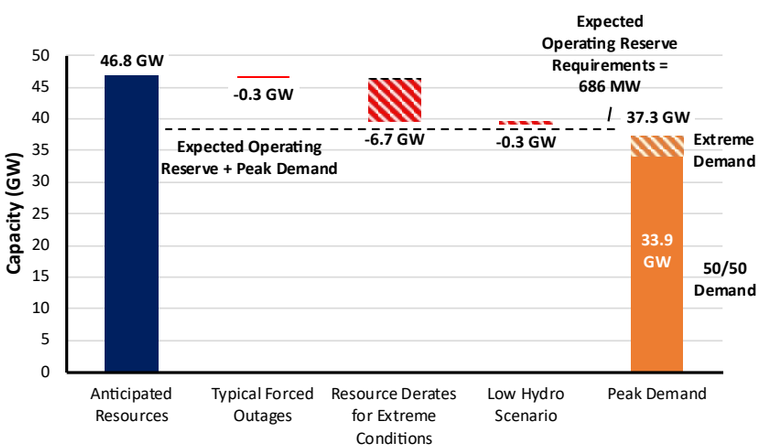
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios.

On-Peak Fuel Mix



2026–2027 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

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Thermal, wind, and solar are incremental reductions based on the hourly availability curves' probability distribution's 10th percentile "extreme scenario."

Natural Gas Fuel Constraint Risk: Derates reflect highest reported hourly capacity of single-fuel gas generators on forced outage due to "lack of fuel" during recent winter storms, 174 MW.

Low-Hydro Scenario: Estimated derate for lower hydro output



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 36 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

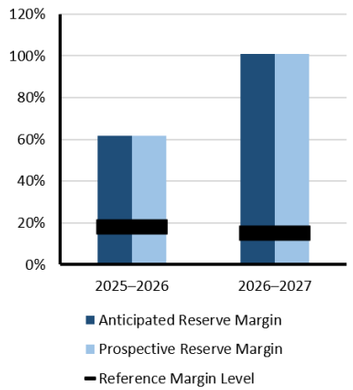
Highlights

- Operators in the assessment area can meet operating reserve requirements for the range of assessed scenarios this winter including the extreme winter peak demand of 13,188 MW, with extreme forced outages and resource derates.
- Recent retirement of WECC's regional standards for contingency reserves has lowered reserve requirements from 673 MW to 276 MW.
- Total internal winter demand is expected to increase significantly from last winter (+779 MW/6.8 percent) while demand response has also increased, partially offsetting load growth during peak demand periods.
- Resource additions since last winter, including large wind and battery storage projects, have caused an increase in overall reserves margins and one third of Tier 1 resource capacity has been verified to be on-line.

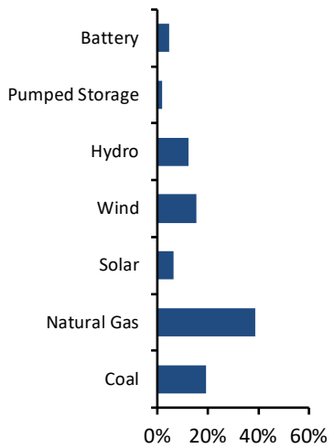
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios.

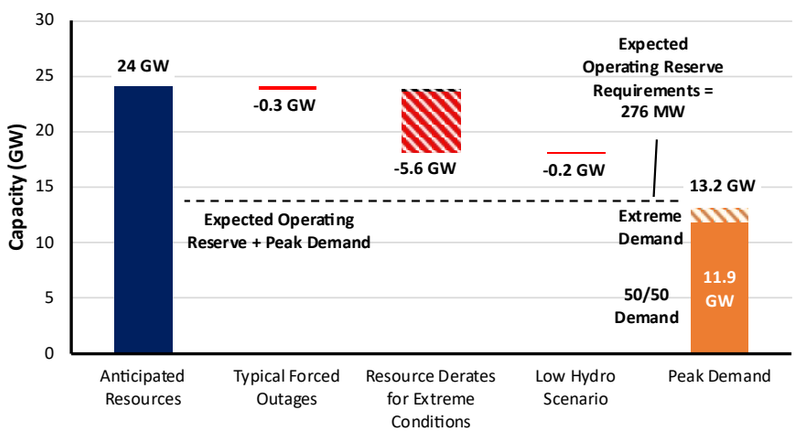
On-Peak Reserve Margin



On-Peak Fuel Mix



2026–2027 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario and also reflects highest reported hourly capacity of single-fuel gas generators on forced outage due to "lack of fuel" during recent winter storms, 51 MW



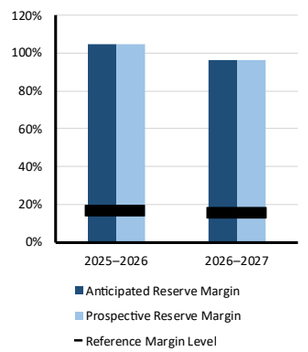
WECC-Southwest

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 36 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- Operators in the assessment area can meet operating reserve requirements for the range of assessed scenarios this winter. This includes extreme winter peak demand of 25,635 MW, with extreme forced outages and resource derates.
- Recent retirement of WECC's regional standards for contingency reserves has lowered reserve requirements in the assessment area from 1,258 MW to 608 MW.
- Peak demand is forecast to increase by 2.9 GW (14.6%) since last winter, however added resource capacity, including a large amount of wind resources and battery storage, has exceeded peak demand growth resulting in increased area planning reserves.
- More than 60 percent of Tier 1 capacity has been verified operational.

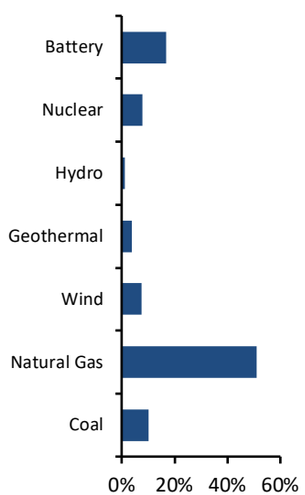
On-Peak Reserve Margin



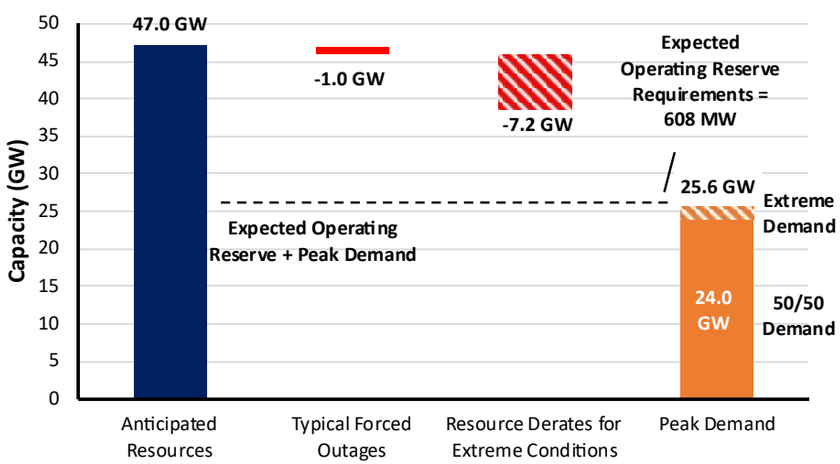
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios.

On-Peak Fuel Mix



2026–2027 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

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Thermal, wind, and solar are incremental reductions based on the hourly availability curves' probability distribution's 10th percentile "extreme scenario"

All-Hours Probabilistic Risk Assessment

Table 8 summarizes results of Regional Entity and assessment area resource adequacy risk assessments. The analysis examines all hours of the season and accounts for shortfall risk during peak demand and off-peak periods. 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 may include LOLE, LOLH, EUE, and the probabilities of EEA occurrence.

Table 8: All-Hours Probability Risk Assessment

Area	Type of Assessment	Results and Insight from Assessment
MRO-MISO	Probabilistic analysis performed by MISO for the 2026–2027 PY and in the *Loss of Load Expectation Study Report*. NERC *2024 LTRA*.	In the MISO PY *2026–2027 LOLE Study Report*, MISO shows that a portion of its annual risk profile is present in the winter season. ARMs for the upcoming winter exceed LOLE study targets, indicating that load-loss risk is below is below LOLE of the 1-day-in-10-years target. Additionally, MISO analysis for the NERC *2024 LTRA* found negligible LOLH and EUE for Winter 2026–2027.
MRO-Manitoba	NERC *2024* and *2025 LTRA*	Manitoba Hydro's probability-based resource adequacy risk assessment for the December–February winter period is that there is a low risk of resource adequacy issues for Winter 2026–2027. The preliminary probabilistic study for 2025 (i.e., the 2025 ProbA) shows under the 2027 base case that there is no discernible winter loss of load risk when evaluating 44 flow years.
MRO-SaskPower	Probability-based capacity adequacy assessment for the 2026–2027 Winter season	SaskPower conducted a probability-based capacity adequacy assessment for the December–February winter period This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). The LOLH for the 2026–2027 Winter season is 0.079 hours. The month with the highest LOLH is February (0.036 hours).
MRO-SPP	NERC *2024 LTRA*	The *2024 LTRA* ProbA for SPP found negligible LOLH and EUE for the 2026 study year. However, the demand forecast for winter is now higher than in the 2024 ProbA study, contributing to smaller planning reserves and more risk of unserved energy.
NPCC	NPCC Probabilistic Study of the 2026–2027 Winter	A probabilistic-based assessment for NPCC assessment areas was conducted, modeling NPCC and its neighboring areas. The analysis 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 expected and low-likelihood, reduced-resource conditions.[17]
NPCC-Maritimes		No cumulative LOLE, LOLH, or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.[18] The Maritimes Area low-likelihood resource case assumed: wind de-rated by 50% for every hour in December through February to simulate icing conditions and a 50% natural gas capacity curtailment to simulate a reduction in gas supply for December through February (dual-fuel units assumed reverting to oil).

[17] Based on September 2026 results.
[18] Rounded to the nearest whole occurrence, NPCC does not consider likelihoods of less than 0.5 days/period to be significant.

Table 8: All-Hours Probability Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-New England		No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.[8] The New England area low-likelihood resource case assumed: 500 MW of additional maintenance outages, significant natural-gas-fired generation unavailability due to fuel supply constraints, and 50% reduced import capabilities of external ties.
NPCC-New York		No cumulative LOLE, LOLH, or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.[8] The New York area low-likelihood resource case assumed: ~500 MW of extended maintenance in southeastern New York and 630 MW of cable transmission reduction across HVDC facilities. The NPCC *2026–2027 Winter Probabilistic Assessment* assumptions align with the New York installed capacity requirements (ICR) for the May 2026–April 2027 period. The base-case assumptions rely on historical gas and oil availability and are modeled directly as a function of load level. Since fuel constraints are already included in the NYISO base case, they were not stressed further in the severe case.
NPCC-Ontario		No cumulative LOLE, LOLH, or EUE risks were indicated over the December–February winter period, for all the scenarios modeled. The Ontario area low-likelihood resource case assumed: 500 MW reduction in natural-gas-fired generation available due to fuel-related constraints.
NPCC-Québec		No cumulative LOLE, LOLH, or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.[8] The Québec area low-likelihood resource case assumed: 1,000 MW of generation reductions.
PJM	NERC *2024 LTRA*	The *2024 LTRA* ProbA for PJM found LOLH exceeding 0.1 days per year for 2026–2027 Winter, resulting in an assessment of elevated risk. The study found that most risk of unserved energy was concentrated in the winter months. Planning Reserve Margins for the upcoming winter indicate that the *2024 LTRA* ProbA results remain reasonable and the area is at risk of unserved energy.
SERC	NERC *2025 LTRA*	SERC's probabilistic assessment of 2026–2027 winter reliability is based on the 2025 NERC ProbA base-case results
SERC-Central		Results of the ProbA base case were negligible expected values for LOLH and EUE.
SERC-East		Results of the ProbA base case were expected values exceeding 0.1 LOLH and over 224 MWh (1 ppm) of EUE. Changes in load and resources since this study was performed are not expected to materially improve these metrics.
SERC-Southeast		Results of the ProbA base case were negligible expected values for LOLH and EUE.

Table 8: All-Hours Probability Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
SERC-Florida Peninsula		Results of the ProbA base case were negligible expected values for LOLH and EUE.
Texas RE-ERCOT	ERCOT Monte Carlo monthly probabilistic study of the 2026-2027 Winter	The simulation indicates that the probability of declaring an EEA is low, much less than 10% for any hour. ERCOT defines elevated risk as an hourly EEA probability that exceeds 10%. The hour with the highest EEA risk is hour ending 8 a.m.—the forecasted peak load hour—with a probability of about 2.7%. The probability of controlled load shed for this hour is 2.1%.
WECC	WECC probabilistic study of the 2026–2027 Winter	WECC ran an hourly probabilistic study for the January 2026–February 2027 time frame by running years 2026 and 2027 in SERVM.
WECC-AB		No unserved energy events were observed in the December–February winter period.
WECC-BC		No unserved energy events were observed in the December–February winter period.
WECC-CA		No unserved energy events were observed in the December–February winter period.
WECC-NW		No unserved energy events were observed in the December–February winter period.
WECC-SW		No unserved energy events were observed in the December–February winter period.
WECC-RM		No unserved energy events were observed in the December–February winter 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[19] or total internal demand for the summer and winter of each year.[20]
- Total internal demand projections are based on normal weather (50/50 distribution)[21] and are provided on a coincident[22] basis for most assessment areas.
- Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the winter 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.

[19] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards.
[20] The summer season represents June–September and the winter season represents December–February.
[21] 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.
[22] 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.

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.

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 winter 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 winter 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.[23] 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 2026–2027 Winter as shown in **Figure 6**.

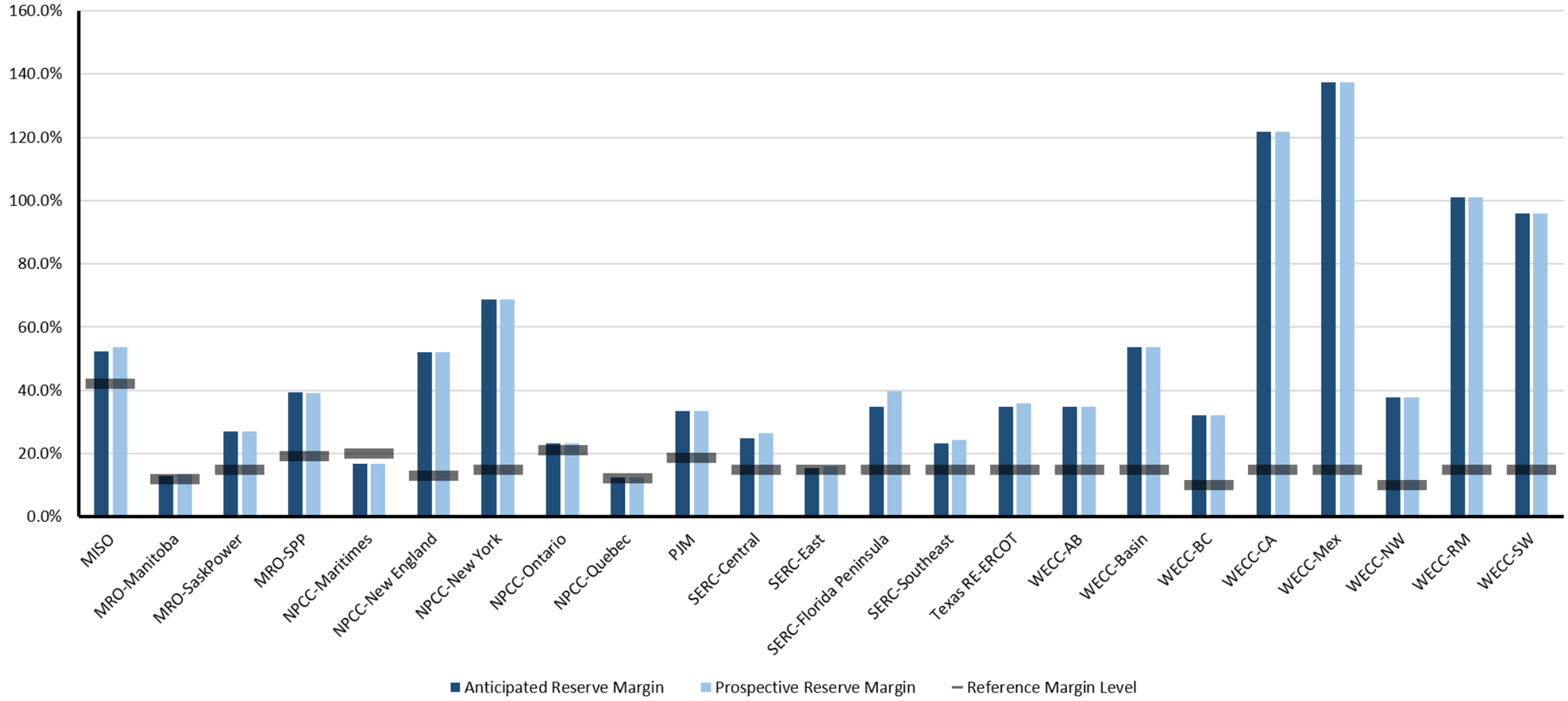


Figure 6: Winter 2026–2027 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[23] 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.

Anticipated Reserve Margin Changes from Year to Year

Figure 7 provides the relative change in the forecast ARMs from the 2025–2026 Winter to the 2026–2027 Winter. Additional details are provided in the **Data Concepts and Assumptions** section.

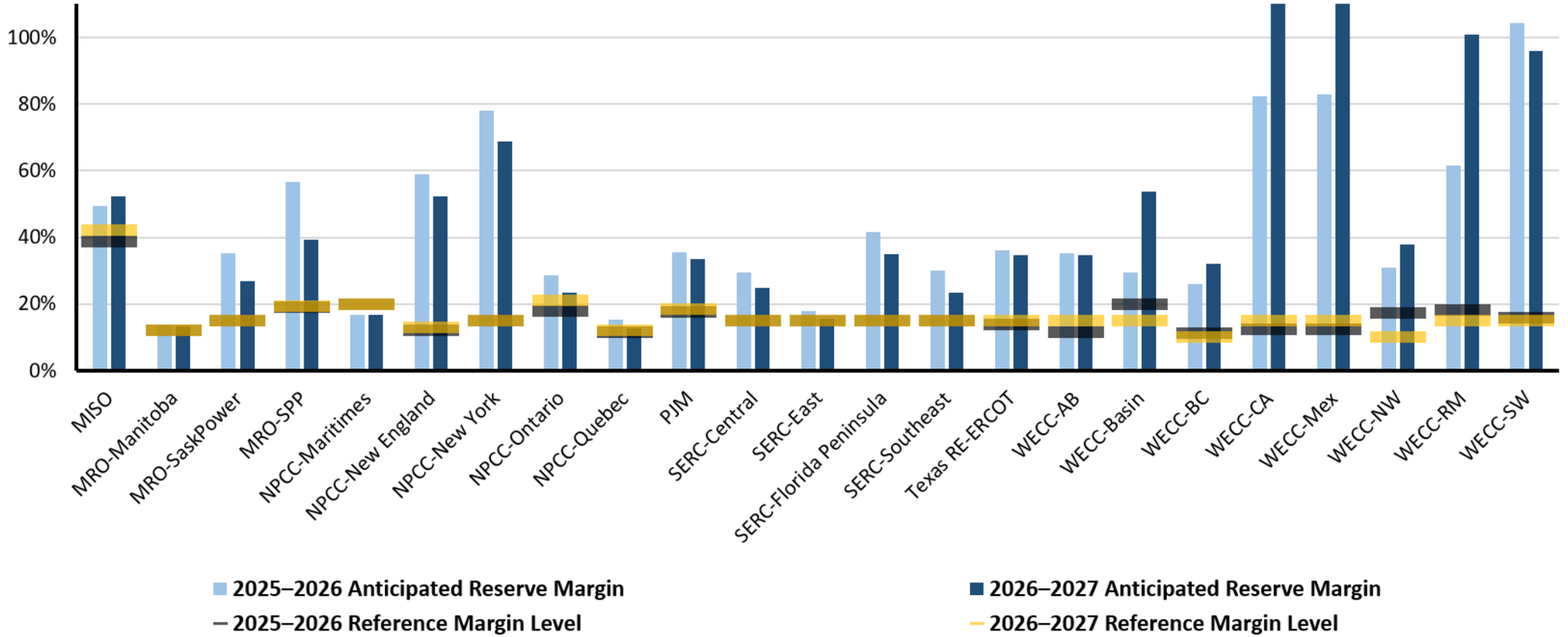


Figure 7: Winter 2025–2026 and Winter 2026–2027 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in **Figure 8**.[24] Assessment areas develop these forecasts based on historical load and weather information as well as other long-term projections. Most assessment areas are showing increasing demand for the upcoming winter compared with the last WRA.

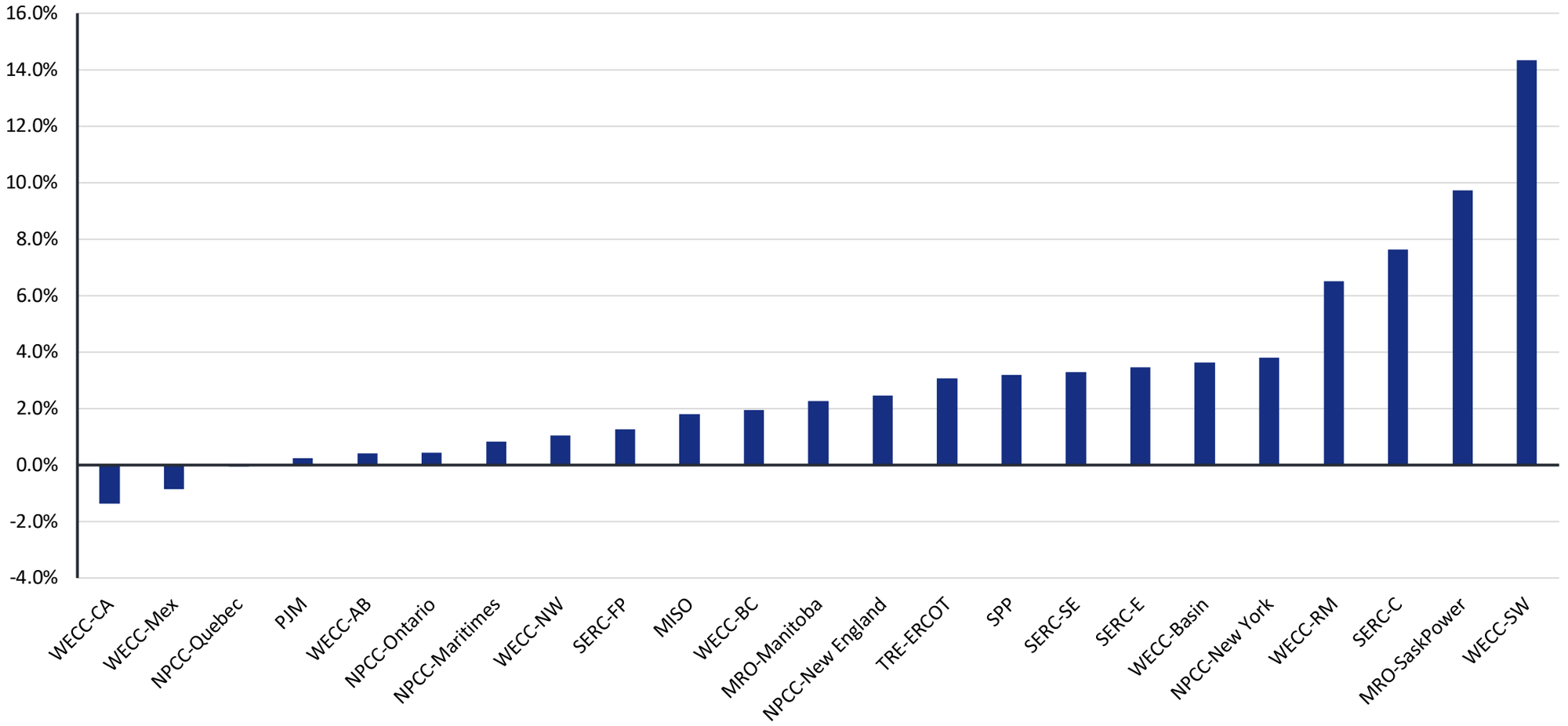


Figure 8: Change in Net Internal Demand—Winter 2025–2026 Forecast Compared to Winter 2026–2027 Forecast

[24] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area along with year over year comparisons are as follows in each table (in alphabetical order).

MRO-MISO			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	105,249	107,213	1.9%
Demand Response: Available	8,205	8,416	2.6%
Net Internal Demand	97,045	98,797	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	142,880	147,980	3.6%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	2,113	2,436	15.3%
Anticipated Resources	144,993	150,416	3.7%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	144,993	151,765	4.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	49.4%	52.2%	2.8
Prospective Reserve Margin	49.4%	53.6%	4.2
Reference Margin Level	38.6%	42.2%	3.6

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,903	5,165	5.3%
Demand Response: Available	0	151	0.0%
Net Internal Demand	4,903	5,014	2.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,688	5,785	1.7%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-113	-112	-1.3%
Anticipated Resources	5,575	5,673	1.8%
Existing-Other Capacity	13	22	69.5%
Prospective Resources	5,588	5,695	1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	13.7%	13.1%	-0.6
Prospective Reserve Margin	14.0%	13.6%	-0.4
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,944	4,323	9.6%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,894	4,273	9.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,972	5,135	3.3%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	5,262	5,425	3.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,262	5,425	3.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	35.1%	27.0%	-8.2
Prospective Reserve Margin	35.1%	27.0%	-8.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	47,168	48,895	3.7%
Demand Response: Available	1,091	1,347	23.5%
Net Internal Demand	46,077	47,547	3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,074	65,370	-8.0%
Tier 1 Planned Capacity	1087	1009	-7.2%
Net Firm Capacity Transfers	-32	-160	398.6%
Anticipated Resources	72,129	66,219	-8.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	73,029	66,173	-9.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	56.5%	39.3%	-17.3
Prospective Reserve Margin	58.5%	39.2%	-19.3
Reference Margin Level	19.0%	19.3%	0.3

NPCC-Maritimes

Demand, Resource, and Reserve Margins	2025–2026 WRA	2026–2027 WRA	2025–2026 vs. 2026–2027
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	6,061	6,213	2.5%
Demand Response: Available	248	351	41.6%
Net Internal Demand	5,813	5,862	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,704	6,798	1.4%
Tier 1 Planned Capacity	88	73	-17.5%
Net Firm Capacity Transfers	1	-32	N/A
Anticipated Resources	6,794	6,838	0.7%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,800	6,838	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.9%	16.7%	-0.2
Prospective Reserve Margin	17.0%	16.7%	-0.3
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York

Demand, Resource, and Reserve Margins	2025–2026 WRA	2026–2027 WRA	2025–2026 vs. 2026–2027
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,200	24,620	1.7%
Demand Response: Available	1,027	568	-44.7%
Net Internal Demand	23,173	24,052	3.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,080	39,662	-1.0%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	1,203	909	-24.4%
Anticipated Resources	41,283	40,571	-1.7%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,283	40,571	-1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	78.2%	68.7%	-9.5
Prospective Reserve Margin	78.2%	68.7%	-9.5
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England

Demand, Resource, and Reserve Margins	2025–2026 WRA	2026–2027 WRA	2025–2026 vs. 2026–2027
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,056	20,483	2.1%
Demand Response: Available	440	384	-12.7%
Net Internal Demand	19,616	20,099	2.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,935	30,174	0.8%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	1,235	409	-66.9%
Anticipated Resources	31,170	30,583	-1.9%
Existing-Other Capacity	322	0	-100.0%
Prospective Resources	31,492	30,583	-2.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	58.9%	52.2%	-6.7
Prospective Reserve Margin	60.5%	52.2%	-8.4
Reference Margin Level	12.0%	13.0%	1.0

NPCC-Ontario

Demand, Resource, and Reserve Margins	2025–2026 WRA	2026–2027 WRA	2025–2026 vs. 2026–2027
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,013	21,954	-0.3%
Demand Response: Available	868	716	-17.5%
Net Internal Demand	21,146	21,238	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,319	26,077	-4.5%
Tier 1 Planned Capacity	294	120	-59.3%
Net Firm Capacity Transfers	-420	0	N/A
Anticipated Resources	27,193	26,196	-3.7%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	27,193	26,196	-3.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.6%	23.3%	-5.3
Prospective Reserve Margin	28.6%	23.3%	-5.3
Reference Margin Level	18.0%	21.0%	3.1

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,799	40,883	0.2%
Demand Response: Available	4,902	5,001	2.0%
Net Internal Demand	35,897	35,882	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,698	40,165	-3.7%
Tier 1 Planned Capacity	61	121	99.2%
Net Firm Capacity Transfers	-390	105	N/A
Anticipated Resources	41,368	40,391	-2.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,368	40,391	-2.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.2%	12.6%	-2.7
Prospective Reserve Margin	15.2%	12.6%	-2.7
Reference Margin Level	11.5%	12.2%	0.7

SERC-Central [25]			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,875	45,716	6.6%
Demand Response: Available	2,809	2,594	-7.7%
Net Internal Demand	40,067	43,122	7.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	49,999	49,316	-1.4%
Tier 1 Planned Capacity	0	2,231	0.0%
Net Firm Capacity Transfers	1,847	2,333	26.3%
Anticipated Resources	51,846	53,879	3.9%
Existing-Other Capacity	1,810	619	-65.8%
Prospective Resources	53,656	54,498	1.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.4%	24.9%	-4.4
Prospective Reserve Margin	33.9%	26.4%	-7.5
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	140,827	142,536	1.2%
Demand Response: Available	5,998	7,394	23.3%
Net Internal Demand	134,829	135,142	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	178,335	177,207	-0.6%
Tier 1 Planned Capacity	0	50	0.0%
Net Firm Capacity Transfers	4,448	3,142	-29.4%
Anticipated Resources	182,783	180,399	-1.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	182,452	180,399	-1.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	35.6%	33.5%	-2.1
Prospective Reserve Margin	35.3%	33.5%	-1.8
Reference Margin Level	17.7%	18.6%	0.9

SERC-East [26]			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,703	47,686	4.3%
Demand Response: Available	888	1,317	48.3%
Net Internal Demand	44,815	46,369	3.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	52,668	53,463	1.5%
Tier 1 Planned Capacity	11	14	20.6%
Net Firm Capacity Transfers	150	69	-54.0%
Anticipated Resources	52,830	53,546	1.4%
Existing-Other Capacity	5,832	265	-95.5%
Prospective Resources	58,661	53,811	-8.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.9%	15.5%	-2.4
Prospective Reserve Margin	30.9%	16.0%	-14.9
Reference Margin Level	15.0%	15.0%	0.0

[25] 2025-26 capacity adjusted to reflect solar on-peak contribution

[26] 2025-26 capacity adjusted to reflect solar on-peak contribution

SERC-Florida Peninsula [27]			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,628	49,209	1.2%
Demand Response: Available	3,127	3,135	0.3%
Net Internal Demand	45,501	46,074	1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,502	61,384	-3.3%
Tier 1 Planned Capacity	692	582	-15.8%
Net Firm Capacity Transfers	300	176	-41.3%
Anticipated Resources	64,494	62,142	-3.6%
Existing-Other Capacity	3,671	2,223	-39.5%
Prospective Resources	68,165	64,365	-5.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.7%	34.9%	-6.9
Prospective Reserve Margin	49.8%	39.7%	-10.1
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	77,387	79,509	2.7%
Demand Response: Available	9,330	9,370	0.4%
Net Internal Demand	68,057	70,139	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	89,977	94,452	5.0%
Tier 1 Planned Capacity	1,351	70	-94.8%
Net Firm Capacity Transfers	1,235	20	-98.4%
Anticipated Resources	92,562	94,542	2.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	93,137	95,262	2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.0%	34.8%	-1.2
Prospective Reserve Margin	36.9%	35.8%	-1.0
Reference Margin Level	13.75%	15.0%	1.3

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	47,056	48,886	3.9%
Demand Response: Available	1,365	1,688	23.7%
Net Internal Demand	45,691	47,198	3.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	58,878	58,836	-0.1%
Tier 1 Planned Capacity	0	336	0.0%
Net Firm Capacity Transfers	489	-983	-301.0%
Anticipated Resources	59,367	58,188	-2.0%
Existing-Other Capacity	4,847	547	-88.7%
Prospective Resources	64,214	58,735	-8.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.9%	23.3%	-6.6
Prospective Reserve Margin	40.5%	24.4%	-16.1
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,411	12,463	0.4%
Demand Response: Available	0	0	0.0%
Net Internal Demand	12,411	12,463	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	16,658	16,387	-1.6%
Tier 1 Planned Capacity	124	224	80.3%
Net Firm Capacity Transfers	0	185	0.0%
Anticipated Resources	16,782	16,796	0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	16,782	16,796	0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	35.2%	34.8%	-0.5
Prospective Reserve Margin	35.2%	34.8%	-0.5
Reference Margin Level	11.5%	15.0%	3.5

[27] 2025-26 capacity adjusted to reflect solar on-peak contribution

WECC-Basin			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,758	11,130	3.5%
Demand Response: Available	170	158	-7.1%
Net Internal Demand	10,588	10,972	3.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,183	15,213	15.4%
Tier 1 Planned Capacity	533	1587	197.6%
Net Firm Capacity Transfers	0	72	0.0%
Anticipated Resources	13,717	16,872	23.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	13,717	16,872	23.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.6%	53.8%	24.2
Prospective Reserve Margin	29.6%	53.8%	24.2
Reference Margin Level	20.0%	15.0%	-5.0

WECC-CA			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	36,281	35,807	-1.3%
Demand Response: Available	666	676	1.5%
Net Internal Demand	35,614	35,131	-1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	57,923	69,745	20.4%
Tier 1 Planned Capacity	6997	1435	-79.5%
Net Firm Capacity Transfers	0	6,717	0.0%
Anticipated Resources	64,920	77,896	20.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	64,920	77,896	20.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	82.3%	121.7%	39.4
Prospective Reserve Margin	82.3%	121.7%	39.4
Reference Margin Level	12.5%	15.0%	2.5

WECC-BC			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	Not Reported	Not Reported	1.9%
Demand Response: Available	0	0	0.0%
Net Internal Demand	Not Reported	Not Reported	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,389	15,249	6.0%
Tier 1 Planned Capacity	637	0	-100.0%
Net Firm Capacity Transfers	0	822	0.0%
Anticipated Resources	15,026	16,071	7.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	15,026	16,071	7.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.9%	32.1%	6.2
Prospective Reserve Margin	25.9%	32.1%	6.2
Reference Margin Level	11.4%	10.0%	-1.4

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	1,977	1,960	-0.8%
Demand Response: Available	0	0	0.0%
Net Internal Demand	1,977	1,960	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,619	4,704	30.0%
Tier 1 Planned Capacity	0	825	0.0%
Net Firm Capacity Transfers	0	-875	0.0%
Anticipated Resources	3,619	4,654	28.6%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,619	4,654	28.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	83.1%	137.4%	54.3
Prospective Reserve Margin	83.1%	137.4%	54.3
Reference Margin Level	12.5%	15.0%	2.5

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	33,604	34,003	1.2%
Demand Response: Available	30	74	147.3%
Net Internal Demand	33,574	33,929	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	34,671	40,883	17.9%
Tier 1 Planned Capacity	3,152	330	-89.5%
Net Firm Capacity Transfers	6,136	5,559	-9.4%
Anticipated Resources	43,959	46,771	6.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	43,959	46,771	6.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.9%	37.9%	6.9
Prospective Reserve Margin	30.9%	37.9%	6.9
Reference Margin Level	17.2%	10.0%	-7.2

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,147	24,237	14.6%
Demand Response: Available	177	263	48.6%
Net Internal Demand	20,970	23,974	14.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,135	45,118	12.4%
Tier 1 Planned Capacity	2733	6950	154.3%
Net Firm Capacity Transfers	0	-5,083	0.0%
Anticipated Resources	42,868	46,984	9.6%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,868	46,984	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	104.4%	96.0%	-8.4
Prospective Reserve Margin	104.4%	96.0%	-8.4
Reference Margin Level	16.0%	15.0%	-1.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2025–2026 WRA**	**2026–2027 WRA**	**2025–2026 vs. 2026–2027**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,501	12,280	6.8%
Demand Response: Available	285	334	17.2%
Net Internal Demand	11,216	11,946	6.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,768	19,273	8.5%
Tier 1 Planned Capacity	366	2766	656.0%
Net Firm Capacity Transfers	0	1,960	0.0%
Anticipated Resources	18,134	23,999	32.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	18,134	23,999	32.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	61.7%	100.9%	39.2
Prospective Reserve Margin	61.7%	100.9%	39.2
Reference Margin Level	18.2%	15.0%	-3.2

Variable Energy Resource Contributions During Peak Hour by Assessment Area

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. In many areas, winter demand peaks in the early morning hours or other times of darkness, resulting in little or no electrical resource output from solar PV resources. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar			Run of River Hydro			Energy Storage Systems		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate Batteries	Expected Batteries	Expected Share of Nameplate (%)
MISO	30,698	9,867	32%	23,873	1,255	5%	2,348	1,458	62%	1,046	996	95%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	202	54	27%	0	0	0%
MRO-SaskPower	816	451	55%	30	1	3%	121	103	85%	0	0	0%
MRO-SPP	36,818	10,903	30%	5,368	736	14%	114	52	45%	2,468	1,160	47%
NPCC-Maritimes	1,800	325	18%	157	0.1	0%	906	901	99%	150	99	66%
NPCC-New England	3,752	1,258	34%	1,728	16	1%	624	270	43%	894	894	100%
NPCC-New York	2,983	890	30%	573	0	0%	973	442	45%	105	23	22%
NPCC-Ontario	4,943	1,968	40%	478	190	40%	0	0	0%	1,164	582	50%
NPCC-Québec	4,560	1,547	34%	10	0	0%	445	445	100%	0	0	0%
PJM	12,829	4,867	38%	16,880	0	0%	3,044	2,853	94%	508	206	41%
SERC-Central	1,324	168	13%	2,050	0	0%	3,387	1,974	58%	180	180	100%
SERC-East	0	0	0%	7,843	0	0%	512	498	97%	323	135	42%
SERC-Florida Peninsula	0	0	0%	13,502	208	2%	0	0	0%	1,145	1,145	100%
SERC-Southeast	0	0	0%	9,412	0	0%	1,435	1,438	100%	401	401	100%
Texas RE-ERCOT	40,645	16,422	40%	41,992	15	0%	0	0	0%	20,966	3,307	16%
WECC-AB	5,684	1,687	30%	2,275	0	0%	896	670	75%	261	222	85%
WECC-Basin	5,890	1,686	29%	4,531	0	0%	873	546	63%	655	557	85%
WECC-BC	753	143	19%	17	0	0%	1,871	1,646	88%	0	0	0%
WECC-CA	8,359	2,427	29%	28,001	0	0%	1,121	852	76%	16,712	14,205	85%
WECC-Mex	296	90	30%	350	0	0%	0	0	0%	0	0	0%
WECC-NW	10,019	2,867	29%	1,729	162	9%	14,088	10,392	74%	542	461	85%
WECC-RM	8,929	3,387	38%	4,117	1,415	34%	105	104	99%	342	291	85%
WECC-SW	8,861	3,337	38%	14,963	91	1%	377	198	52%	6,240	5,304	85%
EASTERN INTERCONNECTION	96,222	30,750	32%	81,894	2,406	3%	13,666	10,044	73%	8,382	5,821	69%
QUÉBEC INTERCONNECTION	4,560	1,547	34%	10	0	0%	445	445	100%	0	0	0%
TEXAS INTERCONNECTION	40,645	16,422	40%	41,992	15	0%	0	0	0%	20,966	3,307	16%
WECC INTERCONNECTION	48,791	15,623	32%	55,983	1,668	3%	19,331	14,407	75%	24,752	21,039	85%
INTERCONNECTION TOTAL:	**190,219**	**64,341**	**34%**	**179,879**	**4,089**	**2%**	**33,441**	**24,896**	**74%**	**54,100**	**30,167**	**56%**

Review of Winter 2025–2026 Capacity and Energy Performance

Eastern Interconnection–Canada and Québec Interconnection

System operators at the IESO and Hydro Québec experienced a short period of tight operating conditions prompting emergency operating procedures at the start of winter when available capacity was affected by generator outages. Supplies were maintained throughout the period. Ontario's peak electricity demand occurred in late January along with most other areas in the Eastern half of North America. Grid operators did not need to employ special operating procedures to manage reliability.

Eastern Interconnection–United States

The 2026 Cold Weather Performance Review describes the proactive actions taken in January 2026 to mitigate risks and avoid manual load-shedding. The event affected most parts of the Eastern Interconnection:

- System operators at ISO-NE issued an alert for abnormal operating conditions ahead of extreme winter conditions and remained in the alert from January 25 to February 11. The alert provided for more restrictive transmission and generator outage posture. ISO-NE did not experience a capacity deficiency during the period.
- In New York, operators implemented the DR program during the period when demand was forecast to exceed seasonal projections. DR is estimated to have reduced demand by 400 MW.
- MISO was able to manage reliability by using LMRs to retain operating reserves through the lowest margin hours on January 24. Abnormally high unplanned outages contributed to the lower margins.
- SPP system operators implemented actions to mitigate energy emergencies and maintain system reliability during . These included issuing resource advisories and conservative operations alert to ensure that generating units were available and prepared for potential high-demand periods. Operators prioritized the dispatch of available units, coordinated closely with neighboring regions to secure imports when needed, and utilized DR resources to reduce system load during critical hours. Enhanced real-time monitoring and communication protocols were also employed to identify and address emerging reliability threats promptly.
- Some energy emergencies were issued in the U.S. Southeast to manage above-normal electricity demand and limited supplies as generator outages rose across the region. Arctic air extended as far as Florida, where sustained and forecasted cold weather resulted in elevated demand and tightening operating margins. Operators implemented conservative operating procedures, issued generating capacity advisories, and conducted periodic capacity coordination calls. Some operators dipped into contingency reserves to serve load when available capacity was insufficient.

Texas Interconnection–ERCOT

The late-January 2026 arctic event affected Texas, prompting operators at ERCOT to issue a series of communications leading up to the storm, including Extreme Cold Weather Operating Condition Notice, Extreme Cold Weather Watch and Extreme Cold Weather Advisory. Through state and federal action, temporary air-quality environmental waivers were obtained to support maximum generation output and availability. ERCOT deployed Firm Fuel Supply Service (FFSS) resources with a capacity of 445 MW to alleviate the impact of natural gas fuel supply limitations. Following the trip of a large generator in central Texas, the South Texas Export IROL was briefly exceed and other transmission lines between Houston and San Antonio experienced post-contingency overloads. Real Time Co-optimization (RTC) redistributed ancillary service resources and System Operators dispatched a generator that was available under provisions of a Reliability-Must-Run contract to alleviate transmission system overloads and restore the system to reliability operating limits.

Western Interconnection – United States

While Winter 2025–2026 was generally uneventful in terms of a serious weather-driven threat to reliability, the January 2024 extreme cold event that was exacerbated by natural gas supply constraints and planned and forced transmission outages continues to resonate with Regional Entities. Increased attention to the importance of natural gas and electric system coordination continues as entities recognize that the region's natural gas in power generation in the region will remain a critical resource. Also, despite recent increases in battery energy storage system capacity, most such systems are still limited to a maximum of four hours of discharge and can therefore provide very limited resource adequacy support, especially during longer-duration weather events.

2025–2026 Winter Demand and Generation Summary at Peak Demand

Assessment Area	Peak Demand Date	Peak Demand Hour	Demand (MW)	WRA Peak Demand Scenarios[a] (MW)	Generation (MWh)	Transfers (MW)	Wind - Actual (MW)	Solar –Actual (MW)	Battery -Actual (MW)	Forced Outages-Actual (MW)
							Wind – Expected [b](MW)	Solar – Expected[b] (MW)	Battery-Expected[b] (MW)	Forced Outages – Expected (MW)
MRO-MISO	Jan. 27	9:00	105,400	110,419	105,452	52	22,963	749	136	41,366[28]
				105,249			8,772	686	537	21,743
MRO-Manitoba Hydro	Jan. 23	8:00	5,069	5,146	4,464	444 (Import)	188	0	0	403
				4,903			52	0	0	113
MRO-SaskPower	Dec. 11	19:00	3,751	4,018	3,910	5	656	0	0	0
				3,944			433	4	0	238
MRO-SPP	Jan. 26	8:00	45,648	49,526	46,003	281(Import)	8,602	49	422	15,905
				47,168			7,198	457	42	6,200
NPCC-Maritimes	Jan. 25	19:00	5,958	6,643	4,723	570 (Import)	587	0	70	9
				6,167			241	10	0	253
NPCC-New England	Jan. 25	14:00	20,182	21,565	19,113	1256 (Import)	343	37	0	6,587
				20,056			455	0	266	2,641
NPCC-New York	Feb. 7	18:00	24,317	26,266	21,692	2,477 (Import)	1,513	0	0	7,273
				24,200			737	0	0	5,976
NPCC-Ontario	Jan. 23	19:00	22,042	22,758	23,750	2,512	2,532	0	222	1,361
				22,013			1,972	0	132	1,439
NPCC-Québec	Jan. 25	17:00	40,791	44,248	39,134	1,678 (Import)	1,166	0	0	2,314
				40,799			1,426	0	0	1,500
PJM	Jan. 29	8:00	138,575	150,092	141,581	1,911	2,150	2,780	0	16,193
				140,827			5,463	1	0	14,500
SERC-Central	Jan. 26	8:00	44,440	48,456	40,265	3,991 (Import)	156	307	1,229	4,481
				42,875			370	455	85	3,241

[28] MISO peak forced outages occurred January 24, 2026. Peak electricity demand occurred January 27, 2026.

2025–2026 Winter Demand and Generation Summary at Peak Demand

Assessment Area	Peak Demand Date	Peak Demand Hour	Demand (MW)	WRA Peak Demand Scenarios[a] (MW)	Generation (MWh)	Transfers (MW)	Wind - Actual (MW)	Solar –Actual (MW)	Battery -Actual (MW)	Forced Outages-Actual (MW)
							Wind – Expected [b](MW)	Solar – Expected[b] (MW)	Battery-Expected[b] (MW)	Forced Outages – Expected (MW)
SERC-East	Dec. 31	7:00	47,189	48,824	42,801	4,283 (Import)	0	355	47	5,490
				45,703			0	1,792	8	1,943
SERC-Florida Peninsula	Feb. 2	8:00	50,829	50,829	60,484	2485	0	0	1,025	5,722
				48,628			0	2,151	1,152	3,968
SERC-Southeast	Feb. 1	8:00	47,574	55,748	46,429	3,320	266	100	306	1,781
				47,056			0	4,461	105	2,658
Texas RE-ERCOT	Jan. 26	9:00	75,587	94,642	75,251	342	6,589	7,324	4,522	1,420
				77,387			7,833	660	6,007	7,367
WECC-Alberta	Dec. 11	18:00	12,785	12,743	12,645	150 (Import)	2,020	1	0	588
				12,411			1,919	0	-	351
WECC-Basin	Jan. 26	15:00	9,852	11,319	10,491	639	3,999	9	51	393
				10,758			1,148	62	-	1,042
WECC-British Columbia										
WECC-California	Dec. 9	22:00	36,745	38,202	28,145	8,646 (Import)	1,122	?	0	1,567
				36,281			682	0	-	3061
WECC-Northwest	Jan. 26	16:00	30,016	36,971	29,483	527 (Import)	1,250	37	479	2,516
				33,603			1,319	1,556	-	475
WECC-Mexico	Feb. 27	16:00	2,084	2,048	2,022	63	2	174	0	710
				1,977			4	0	-	73
WECC-Rocky Mountain	Jan. 23	16:00	12,156	12,182	6,175	383 (Import)	2,383	88	24	2,875
				11,501			2,265	0	-	948
WECC-Southwest	Jan. 26	17:00	20,547	23,629	21,088	818	991	8,553	-723	3,229
				21,147			1,182	391	-	3,003

Natural Gas Constraints

The North American natural gas transportation system has areas that have historically been constrained in the system's capacity to deliver natural gas to demand centers with a significant consumer population (see **Figure 9**). The constraints are evidenced by high utilization of natural gas pipeline capacity at particularly important delivery points that bridge natural gas supply and consumer demand, particularly in peak winter demand periods when demand in the electric sector is competing with demand for natural gas to heat homes and businesses. Significant drawdowns in natural gas inventories from storage facilities and the use of liquefied natural gas (LNG) imports as supply can also be symptomatic of an area that is pipeline constrained.

Winter 2025–2026 was muted in its lack of significant reliability events on the BPS. The FERC-NERC joint report[29] on the performance of the BPS during the Winter 2026 Arctic Cold Period found that generator outages during the main weather events of the period, winter storms Fern and Gianna, were comparable in magnitude to the outages experienced during the arctic events of January 2025. The natural gas system also performed reliably with limited duration *force majeure* events and pipeline deliveries that were largely maintained even in the face of steep production declines in the New Mexico/Texas and North Louisianna producing regions.

Even without significant BPS or natural gas system disruptions, the utilization of pipeline delivery points in pipeline-constrained regions remained high, topping 100% in some cases. Utilization is calculated using historical scheduling and nominations data for a given period (how much shippers contracted to use for a particular segment or point on the system), divided by the operating capacity the pipeline operator specified for that same period. While "operating capacity" definitions can vary slightly from operator to operator, it generally signifies the capacity available during a specific time based on the operating conditions of that period. High utilization during peak winter stress is typical of the Pacific Northwest, New England, New York, and Southern California, and last season was no exception. Risks related to natural gas fuel assurance are a continuing concern given that demand is projected to grow year on year in most of the areas that are historically pipeline constrained and experienced near maximum utilization last winter.

WECC-NW expects peak total internal demand to grow by 1.2% year on year for the coming winter. Meanwhile, the largest points where Canadian gas is delivered onto two key US northwest natural gas pipelines saw 100% peak utilization last winter. NPCC-New England expects total internal demand to grow by 2.1% year on year, and NPCC-New York demand is expected to grow by 1.7% from last winter when both regions saw utilization at key pipeline delivery points into the regions range from 74% to 103%. WECC-California expects demand to decline by 1.3% year on year, but one of the key pipelines that feeds southern California, El Paso Natural Gas Pipeline, also ferries gas to customers throughout WECC-Southwest before ultimately terminating near the southern part of California's state border. WECC-Southwest peak winter total internal demand is expected to grow by 14.6% year on year. Utilization at El Paso Natural Gas's delivery points into Southern California averaged 87% at peak last winter.

Reliance on natural gas inventories in storage facilities and supplies available through regasification of LNG was also on display last winter. As stated in the FERC-NERC joint report, total weekly natural gas storage withdrawals were 359 Bcf for the week ending January 30, 2026, matching a previous record set in January 2018. On January 29, 2026, Elba Island LNG Terminal in Georgia received its first LNG import since 2020, supplementing regional supplies. In addition to LNG imports, natural gas supplies that typically flow to LNG export facilities can pivot to the seasonally profitable domestic markets during times of high winter demand. Market forces can be one diver of this redirection of natural gas supplies; it can also be driven by LNG facilities preemptively curtailing operations ahead of an expected severe winter storm or other localized supply constraints. Over the past five years, deliveries of natural gas to pipelines that feed LNG facilities have dropped by as much as 9 Bcf/d (or ~40%) from average delivery volumes, as was the case last winter. When that demand outlet shrinks for whatever combination of reasons, those supplies become available to the domestic market.

[29] FERC, NERC Review Shows Bulk-Power System Improvements in Preparation and Coordination During Winter 2026 Arctic Cold Period | Federal Energy Regulatory Commission

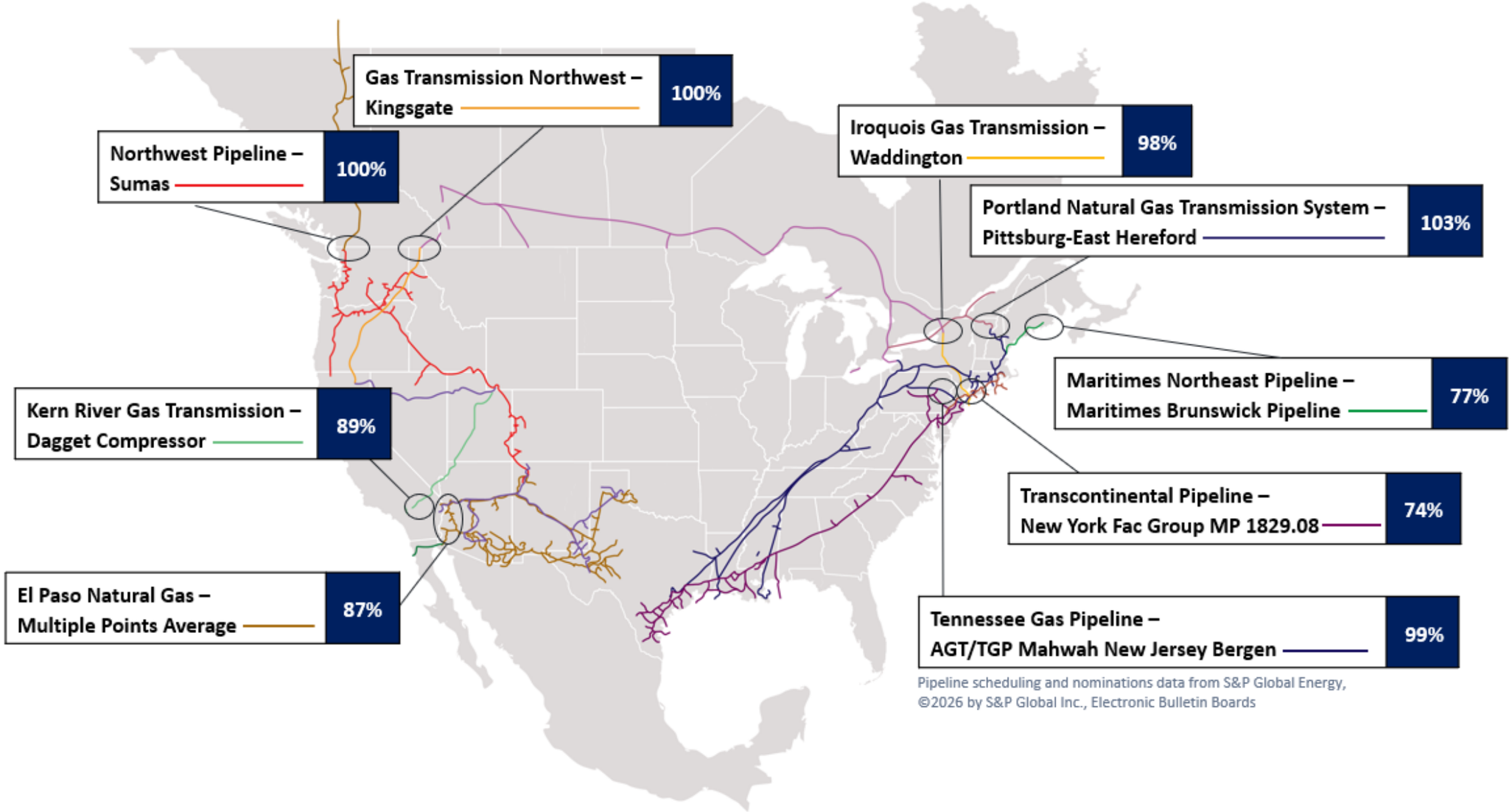


Figure 9: Maximum Daily Natural Gas Pipeline Utilization

Maximum daily utilization (%) at certain points during Winter 2025–2026

Source: Pipeline scheduling and nominations data from S&P Global Energy, Electronic Bulletin Boards

Note: In the absence of historical operating capacity data, NERC used the latest available operating capacity iterated by the pipeline operator to calculate the utilization.