2024–2025 Winter Reliability Assessment

November 2024

Table of Contents

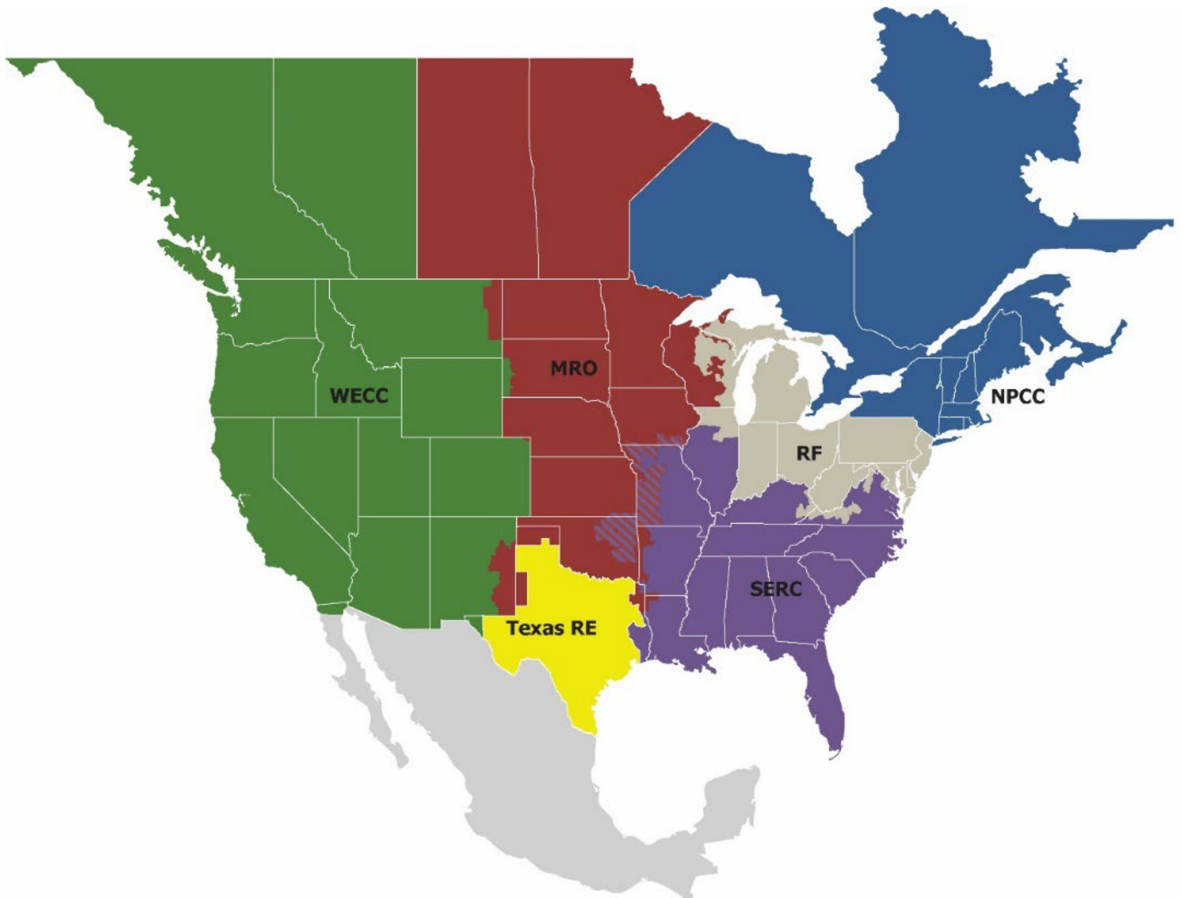
Preface

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

Reliability | Resilience | Security

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

The North American BPS is made up of six Regional Entity 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	WECC

About this Assessment

NERC's *2024–2025 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 the industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

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

1. **All areas are assessed as having adequate resources for normal winter peak-load conditions. However, more extreme winter conditions extending over a wide area could result in electricity supply and energy shortfalls.** Prolonged, wide-area cold snaps can drive sharp increases in electricity demand. Simultaneously, electricity supplies are at risk from freezing temperatures that threaten reliable operation of BPS generators, fuel supply issues for natural-gas-fired generation, and wind and solar resource energy limitations. In three of the past five winters, severe arctic storms have extended across much of North America, causing regional demand for electricity and heating fuel to soar and exposing generation and fuel infrastructure in temperate areas to freezing conditions.[1] The following areas face risks of electricity supply shortfalls during periods of more extreme conditions this winter (see **Figure 1**).

   - **Midcontinent ISO (MISO):** Reduced coal and natural-gas-fired generation by over 5 GW since Winter 2023–2024 has contributed to a decline in available resources. Lower internal capacity is partially offset by a 2 GW increase in firm capacity imports into the area. Additionally, MISO's margin is being helped by a lower peak demand forecast, down over 4 GW since last winter. MISO recently implemented a seasonal resource adequacy construct that more effectively values risks and resource contributions that vary by time of year. With fewer internal dispatchable resources and increasing reliance on wind and imports, the risk of supply shortfall in winter has increased in MISO.

   - **MRO-SaskPower:** Reserve margins have risen this winter by 17 percentage points over the previous winter due to a net increase in peak winter capacity of more than 200 MW, the majority of which consists of natural gas generation capacity (320 MW). Additional natural gas-fired generation capacity has offset the area's 140 MW decline in coal-fired generation capacity. High numbers of forced generator outages or wind turbine cold temperature derates and outages could lead to operating reserve shortfalls at peak winter demand levels.

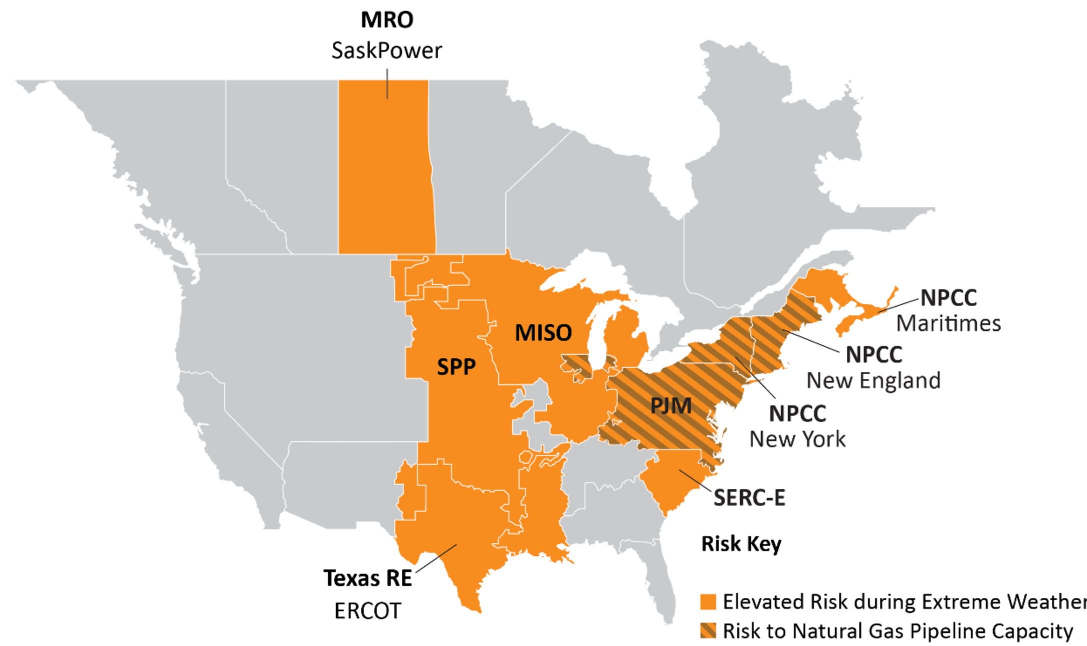


Figure 1: Winter Reliability Risk Area Summary

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

   - **NPCC-Maritimes:** Reserve margins have fallen by 4.6% from the winter of 2023 as forecasted peak demand has grown by more than 5.5% (300 MW). Lower conventional hydro generation capacity has contributed to a drop of 100 MW in total winter generation capacity from last winter. Demand levels at the forecasted peak can strain the area's firm supplies and lead to operating mitigations or energy emergencies.

   - **NPCC-New England:** Dispatchable thermal generation capacity has declined by 2.6 GW as forecasted peak demand has risen by 0.6 GW (+3%). The largest capacity increases year over year were for wind and solar resources at a combined 550 MW; however, both of those resource types have limited energy production in the winter months. Potential

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

natural gas transportation constraints compound the risk of generation capacity shortfall during peak demand periods. ISO-New England's (ISO-NE) Inventoried Energy Program provides compensation for generators that maintain inventoried fuel for their assets during extreme cold periods.

- **NPCC-New York:** The Anticipated Reserve Margin (ARM) of 64.3% remains well above the Installed Reserve Margin (IRM) of 22.0% established by the New York State Reliability Council, despite a 2.6 GW decline in resource capacity since last winter. Operators are likely to be challenged in maintaining sufficient reserves during periods of extreme cold weather if non-firm supply of natural gas to generators is interrupted. New York also faces reduced natural gas supply from a regional pipeline issue (see the natural gas fuel highlight in the next column).
- **PJM:** Despite an increase in winter peak demand forecast of over 3.2 GW (2.5%), Planning Reserve Margins in PJM have risen slightly with increased firm imports and demand response. While no BPS reliability issues are currently anticipated in PJM, natural gas infrastructure capacity could be negatively affected if legal proceedings require the shutdown of facilities that were installed as part of a regional natural gas pipeline expansion project (see the natural gas fuel highlight in the next column). Natural gas is the leading fuel for electricity generation in PJM: In 2023 it was over 44.1% of total generation in the PJM real-time energy market.[2] PJM estimates that fuel service for as much as 20 GW of generation capacity is directly or indirectly served by the pipeline at the center of these proceedings.
- **SERC-East:** Lower forecasted peak demand is contributing to a 0.6% uptick in reserve margins for the winter when compared to 2023. However, there has been a nearly 1 GW decline in dispatchable thermal resources (primarily coal-fired generation) and growth in solar capacity that does little to help meet peak winter demand. Severe cold weather extending into the southern United States could lead to energy emergencies due to operators facing fuel supply issues, increases in generator forced outages, and higher electricity demand.
- **Southwest Power Pool (SPP):** The ARM of 44% is five percentage points higher than last winter, driven primarily by a significant increase in demand-response resources. Forecasted peak demand has risen for this winter by 1.8 GW from the previous year while total existing generation capacity has fallen by more than 4 GW. However, of the 4 GW decline in generation resources, nearly 2 GW come from adjustments in wind and solar capacity contributions, which have a lower energy value during the winter season. At the same time, natural gas generation capacity, which has a higher winter energy value, has expanded by 2.6 GW year over year. The area's vast wind resources (8% of the generation fleet) can alleviate firm capacity shortages under the right conditions; however, energy risks emerge during periods of low wind.
- **Texas RE-ERCOT:** The risk of reserve shortage remains elevated due primarily to robust load growth that continues to surpass growth in dispatchable resources. Net internal demand has risen by more than 2 GW since 2023. Solar and wind capacity has increased by more than 3 GW, while dispatchable resources have only increased by 1 GW. In November 2023, ERCOT introduced firm fuel supply service to address fuel-related outages that can occur when natural gas supplies are limited.

2. **Natural gas fuel to generators is threatened this winter by ongoing concerns with natural gas production and delivery in extreme conditions and a potential regional pipeline capacity issue in the U.S. Mid-Atlantic and Northeast.** Natural gas is an essential fuel for electricity generation in winter. While the natural gas industry is making progress on commercial practices and voluntary commitments to improve winter preparedness, supplies to electric generators remain vulnerable in extreme cold temperatures in many parts of North America, placing electric reliability at risk. As winter approaches, NERC encourages all entities across the gas-electric value chain—from production to the burner tip and the busbar—to take all necessary actions to prepare for extreme cold, keep natural gas flowing, and keep the lights and furnaces on.

   At the time of this WRA, the operator of a major interstate natural gas pipeline expansion project serving the U.S. Mid-Atlantic and Northeast is facing legal challenges to the continued operation of the expanded pipeline. According to a recent Federal Energy Regulatory Commission (FERC) filing, a halting of the expanded pipeline operations would affect "firm transportation capacity in New Jersey, New York, Pennsylvania, Maryland, Delaware, Virginia, North Carolina, South Carolina, Georgia, and Alabama." These states correspond to the PJM, NPCC-New York, SERC-East, and SERC-Southeast assessment areas. During recent extreme winter weather events, each of these areas has experienced or come dangerously close to a shortfall in electricity supply for which fuel availability was a significant factor. Because foreseeable extreme cold temperatures have the potential to push the existing natural gas supply infrastructure to maximum capacity again this winter, a shutdown of in-service regional natural gas facilities would endanger grid reliability.

[2] See the 2023 Annual State of the Market Report for PJM: Volume 2, Section 3: Energy Market, P 209. (March 14, 2024)

3. **Growing winter load underscores the importance of maintaining sufficient dispatchable generation and strong transmission networks.** Winter electric load is growing in most areas as the grid increasingly powers heating, transportation systems, and new data centers. Serving winter load is becoming more challenging and complex as coal-fired and older natural gas-fired generators retire and are replaced by variable and energy-limited resources. Solar resources, which are overwhelmingly the largest share of new resources connecting to the grid, do not provide output during many hours when winter electricity demand is at its highest. New battery resources can extend the output from solar PV for short durations, but winter's longer hours of darkness, cloud cover, and precipitation will push the limits of today's battery storage capabilities and installed energy capacity. Winter resource adequacy depends on dispatchable generation, reliable fuel supplies, and firm transfer agreements.
4. **Regulatory and industry initiatives to address reliability issues from winter storms Elliott and Uri make the grid better prepared for the upcoming winter.** Cold weather reliability standards, generator weatherization efforts, and early commitment of generators in advance of freezing temperatures contributed to fewer generator outages in 2023–2024 winter storms compared to Winter Storm Uri (2021) and Winter Storm Elliott (2022).[3] More accurate weather and load forecasting and better communication among natural gas suppliers, Generator Operators (GOP), and electric grid Balancing Authorities (BA) and Reliability Coordinators (RC) also helped maintain the supply of electricity. Continued vigilance and application of proven mitigations will help reduce reliability risks for the upcoming winter.
5. **The transmission system is recovering from severe damage incurred during the 2024 hurricane season.** The BPS in the U.S. Southeast sustained significant damage in October from hurricanes Helene and Milton, leading to millions of customer outages and damage to hundreds of transmission lines and substations. Over 50,000 utility personnel from across North America worked to restore electricity quickly and safely. Lingering effects that degrade the transmission network can extend for weeks and could make the grid less resilient to extreme winter storms. As restoration in parts of the U.S. Southeast continues, NERC is monitoring the implications for winter reliability.

Recommendations

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

- RCs, BAs, and Transmission Operators (TOP) in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should review recommendations contained in the *2022 Winter Storm Elliott Report* and follow-up actions as well as lessons learned from the 2023–2024 Winter.
- Generator Owners (GO) should complete winter readiness plans and checklists prior to December, deploy weatherization packages well in advance of approaching winter storms, and frequently check and maintain cold weather mitigations while conditions persist.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies. Proactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during January 2024 winter storms Gerri and Heather compared to prior arctic storms.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by supporting requested environmental and transportation waivers as well as public appeals for electricity and natural gas conservation.

[3] See January 2024 Arctic Storms System Performance Review Presentation, FERC Open Meeting, April 25, 2024

Risk Highlights

Generator Availability Risk in Extreme Cold Weather

As noted in past WRAs, the performance of the thermal generating fleet is critical to winter operations.

Cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. GOs and GOPs are now required to implement plans for cold weather preparedness and provide cold weather operating parameters to their RCs, TOPs, and BAs for use in operating plans. During the January 2024 cold snap, there were no instances of system operator-initiated load shed, and generators reported fewer derates/outages as compared to past winter storms. Impacted areas noted improved winter preparedness, proactive generator commitment, improved short-term load forecasting, improved gas generator stability due to variable (i.e., non-ratable) fuel supply methods, and incorporation of operating limitations into operating plans. Natural gas and electric entities also noted positive steps taken to improve preparation for extreme cold weather, highlighting improved communication and coordination.[4]

Generator Fuel Supply Risk

The U.S. Energy Information Administration anticipates a colder winter than last year's relatively mild winter season, leading to a projection that U.S. households that use natural gas to heat their homes will consume 5% more than last winter. In addition, natural gas consumption in the power sector has seen record highs this year. The increased consumption of natural gas for power generation combined with the anticipated year-on-year increase in consumption of natural gas for home heating, particularly in the Midwest, comes as lower natural gas prices have had a chilling effect on natural gas production. The result of higher consumption and lower production is inventory that is settling closer to average volumes after several years of above-average natural gas stockpiles.

Natural-gas-fired power generator availability and output can be threatened when natural gas supplies are insufficient or when the flow of fuel is unable to be maintained. For areas with pipeline capacity that is highly contracted by natural gas local distribution companies, extreme cold weather events create risks for power generators that lack firm natural gas transportation arrangements. Ongoing capacity expansion efforts by pipeline companies aimed at serving growing, firm cold weather demand for natural gas are facing regulatory and legal complications that have slowed the development of multiple critical capacity additions and, in one instance, even of already in-service capacity serving the densely populated Mid-Atlantic area.

On July 30, 2024, the U.S. Court of Appeals for the D.C. Circuit overturned FERC's approval of the Williams Companies' Regional Energy Access project, which had been operating to increase gas delivery capacity to New Jersey by 829 MMcf/d. With the state of this pipeline expansion project in flux, the region is at risk of requiring more gas for electric reliability than is available within current and planned pipeline capacity designed to meet power demand.

More generally, concerns over natural gas production issues during cold weather events remain in the Eastern and Western Interconnections. As one reporting assessment area has noted, there is (outside of Texas) little to no information to indicate that upstream gas producers, gatherers, and processors have improved winterization of their operations. Implementation of Texas PUCT's weatherization standards have improved the estimated weather-related forced outages in the ERCOT Interconnection for the upcoming winter season.

Risk Assessment Discussion

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

[4] System Performance Review of the January 2024 Arctic Storms, FERC Open Meeting: April 25, 2024.

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

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

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

Assessment of Planning Reserve Margins and Operational Risk Analysis

Table 2: Seasonal Risk Scenario Margins			
Assessment Area	Anticipated Reserve Margin	Typical Outages	Extreme Conditions
MISO	55.1%	10.3%	-0.8%
MRO-Manitoba	12.3%	9.9%	7.5%
MRO-SaskPower	37.7%	34.0%	20.2%
NPCC-Maritimes	15.1%	10.7%	-6.2%
NPCC-New England	54.5%	35.9%	4.7%
NPCC-New York	64.3%	38.1%	11.2%
NPCC-Ontario	25.1%	25.1%	18.1%
NPCC-Québec	14.1%	10.0%	-3.5%
PJM	40.6%	28.3%	18.5%
SERC-Central	29.2%	22.1%	17.8%
SERC-East	25.0%	20.6%	10.5%
SERC-Florida Peninsula	37.8%	31.7%	15.6%
SERC-Southeast	42.8%	36.4%	30.8%
SPP	44.0%	16.8%	-0.9%
Texas RE-ERCOT	46.1%	27.3%	-19.3%
WECC-AB	36.3%	34.0%	22.7%
WECC-BC	20.9%	20.8%	-4.3%
WECC-CA/MX	72.4%	63.2%	41.7%
WECC-NW	57.9%	53.5%	12.2%
WECC-SW	94.0%	89.5%	53.0%

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

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

Areas highlighted in orange in **Figure 1** above have been identified as having resource adequacy or energy risks for the winter and are included in the **Key Findings** section's discussion that follows. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced-outage margin is the same as the ARM, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

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

Energy Emergency Alerts

Above-normal generation outages, low resource output, and peak loads similar to those experienced in extreme cold temperatures like Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 are ongoing reliability risks for the upcoming winter. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels		
EEA Level	**Description**	**Circumstances**
EEA 1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required operating reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Table 3: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Deterministic	Some shortfall risk has been identified in scenario analysis. MISO applies a deterministic look at expected system conditions, looking at generation availability under typical and extreme outages and looking at a typical 50/50 load forecast and an extreme 90/10 load forecast. For the upcoming winter season, under an extreme outage and extreme 90/10 load forecast, this is the riskiest scenario for the MISO footprint. This scenario produces the shortest actual reserve margin for January.
MRO-Manitoba	Comparison to the NERC 2022 Probabilistic Assessment (2022 ProbA)	Manitoba Hydro's probability-based resource adequacy risk assessment for the winter season is that there is a low risk of resource adequacy issues for the 2024–2025 Winter. Considering modest growth in load and a long-term outage of several units at Jenpeg Generating Station impacting less than 2% of on-peak capacity, EUE near 30 MWh is a reasonable estimate for the 2024–2025 Winter.
MRO-SaskPower	Probability-based capacity adequacy assessment	The expected number of hours with operating reserve deficiencies for the 2024–2025 Winter season is 0.37 hours. The month with the highest probability of an EEA is December (0.22 hours). The probability of having generation forced outages of 350 MW or greater during the winter is estimated at 12.6%. A risk of supply shortfall exists when generation forced outages at this level coincide with periods of high demand.
MRO-SPP	2022 ProbA Regional Risk Scenarios Report[5]	SPP's 2023 probabilistic analysis of a 90/10 winter demand scenario with increased generator outages revealed small amounts of unserved energy in winter months. The analysis indicates that there is a risk of unserved energy in SPP for the upcoming winter under extreme cold conditions that cause high forced-outage rates or low-wind conditions during periods of above-normal demand.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The assessment evaluates the probabilistic indices of LOLE, LOLH, and EUE. The highest peak load scenario has a 7% probability of occurring.	The assessment forecasts that the NPCC Regional Entity will have an adequate supply of electricity this winter and a low risk of disconnecting load. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are presented below. Final assessment results become available in December.
NPCC-Maritimes	The Maritimes Area low-likelihood resource case assumed: wind derated by 50% for every hour in December through February and a 50% natural gas capacity curtailment for December through February (dual-fuel units assumed reverting to oil) and reduced transfer capabilities.	NPCC's assessment preliminary results indicate that established operating procedures are adequate to maintain a balance between electricity supply and demand for the expected forecast, if needed. However, under the highest peak load level conditions, there is a small estimated cumulative LOLE risk of 0.34 days/period with an associated LOLH of 1.54 hours per period and EUE of 100.7 MWh per period, with the highest risk occurring in January and February. In the low-likelihood reduced resource scenario, the highest peak-load conditions result in an estimated cumulative LOLE risk of approximately 0.92 days per period, with an associated LOLH of 4.97 hours per period and EUE of 353 MWh over the December to February winter period.
NPCC-New England	The New England Area low-likelihood resource case assumes 500 MW of additional maintenance outages, ~4,975 MW of natural gas-fired generation unavailable due to fuel constraints, and 50% reduced import capabilities.	NPCC's assessment preliminary results indicate that operating procedures would not be needed to maintain a balance between electricity supply and demand. Only the low-likelihood reduced resource case, highest peak-load scenario resulted in an estimated cumulative LOLE risk of 0.29 days/period, with associated LOLH (0.68 hour/period) and EUE (343.1 MWh) over the December–February winter period. The NPCC Probabilistic Assessment did not evaluate a prolonged, extreme cold weather event that threatens to exhaust stored liquid fuels.

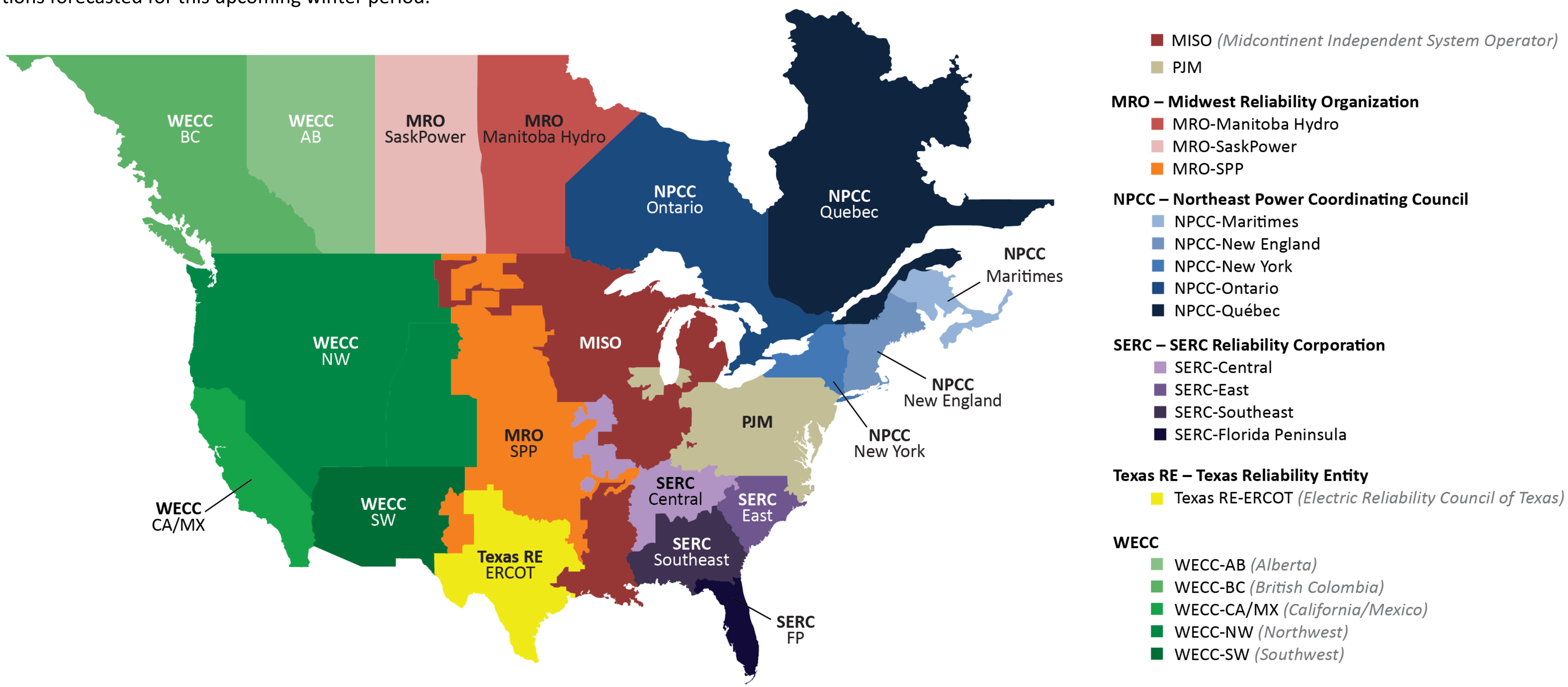
[5] 2022 NERC Probabilistic Assessment Regional Risk Scenario Report

Table 3: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-New York	The New York Area low-likelihood resource case assumed ~500 MW of extended maintenance in southeastern New York, 600 MW transmission reduction across HVDC facilities, and ~5,000 MW of generation unavailable due to fuel delivery issues.	NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH, or EUE risks were indicated over the December–February winter period for all the scenarios modeled.
NPCC-Ontario	The Ontario Area low-likelihood resource case assumed 800 MW of maintenance extended into the winter.	NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH, or EUE risks were indicated over the December–February winter period for all the scenarios modeled.
NPCC-Québec	The Québec Area low-likelihood resource case assumed generation reductions.	NPCC's assessment preliminary results indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand, if needed. No cumulative LOLE, LOLH, or EUE risks were indicated over the December–February winter period for all scenarios modeled.
PJM	Based on 2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 40% IRM, well above the target of 30%. The RRS analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. The RRS report was also influenced by the extreme weather experienced in December 2022. NERC assesses an elevated risk of energy shortfall for the upcoming winter due to the potential for a weather event on the scale of Winter Storm Elliott to cause similar generation outages from fuel and winterization issues.
SERC	The 2022 Probabilistic Assessment studied the years 2024 and 2026. The 2024 winter results are provided here for each assessment area.	
SERC-Central		Based on the study assumptions and results, SERC-Central does not show any winter risk. The EUE is 0.00 MWh and the LOLH is 0.00 hours.
SERC-East	Includes simulation cases with load shapes from 1982 and 1985 that experienced more extreme winters throughout the SERC region, limiting imports from neighboring subregions	SERC-East shows some risk under high-load conditions during winter morning hours around 8 a.m., prior to substantial solar resource output. The EUE is 61.95 MWh and LOLH is 0.06 hours
SERC-Southeast		Based on the study assumptions and results, SERC-Southeast does not show any winter risk. The EUE is 0.00 MWh and the LOLH is 0.00 hours.
SERC-Florida Peninsula	Includes simulation case with weather year 1989, a more extreme winter than usual for Florida and for which case the load forecast error was 4% higher	Based on the study assumptions and results, SERC-Florida Peninsula shows some small risk during winter morning hours with an EUE of 1.09 MWh and LOLH of 0.002 hours. The analysis indicates that the month of greatest risk is December. Contributing conditions include the low solar output associated with early morning and wide-area cold weather events that reduce electricity imports from neighboring areas.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	ERCOT produces a risk assessment for hourly Capacity Available for Operating Reserves (CAFOR) for a future monthly peak-load day. Using its Probabilistic Reserve Risk Model (PRRM), ERCOT conducted a simulation of the forecasted peak load day in January 2025, the winter peak load month. The simulation indicates that the probability of declaring an energy emergency event is low: less than 10% for any hour.

Table 3: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC	WECC uses Multi-Area Variable Resource Integration Convolution (MAVRIC) for probability-based risk assessment. Using convolution and Monte Carlo techniques, MAVRIC compares hourly forecast distributions and analyzes the ability for each load-serving area to maintain a reserve margin that leaves loss of load probability (LOLP) equal to or less than 0.02%. If there are areas with hours above the 0.02% threshold, MAVRIC employs first and second order transfers.	WECC anticipates some risk of falling below the RML during extreme combined outages and/or extreme demand this winter in British Columbia. Note that WECC's forecasted extremes are based on historical data.
WECC-AB		Resources are adequate for expected and extreme (90th percentile) winter scenarios. Despite low resource adequacy risk, maintaining sufficient frequency response capability has been identified as an operational risk in the Alberta system. Frequency response has been declining due to the increasing share of inverter-based resources (IBR) and declining baseload resources. Under-frequency load shedding risk is exacerbated when the Alberta system is islanded or near-islanded from the Western Interconnection.
WECC-BC		British Columbia is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. When hydroelectric generation output is below average, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.
WECC-CA/MX		Operating reserve margins are met before imports in all winter resource availability scenarios.
WECC-NW		WECC-NW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. In a scenario involving high thermal generation outages and low wind output, imports are likely to be needed to meet operating reserves for above-normal peak demand.
WECC-SW		WECC-SW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile.

Regional Assessments Dashboards

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

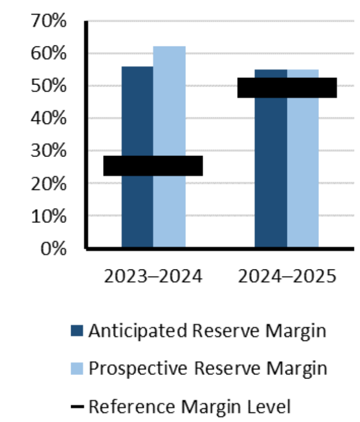


MISO

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.

- MISO has identified some risk for winter in a high generation outage and high winter load scenario. MISO is prepared to maintain reliability by using mitigation measures that include 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 be offered 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.
- Generating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity.
- 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, MISO has filed and implemented changes to the resource adequacy construct to better affirm adequate supply in all seasons.
- MISO's RML for the 2024–2025 Winter is 49.4% on an installed capacity basis. The RML reflects seasonal performance of resources.

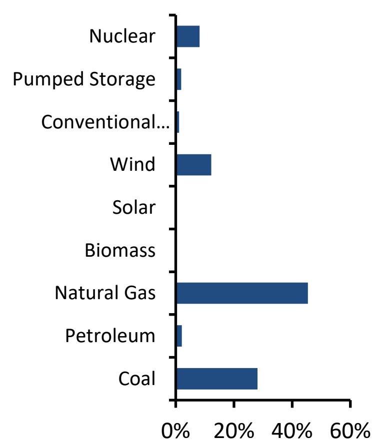
On-Peak Reserve Margin



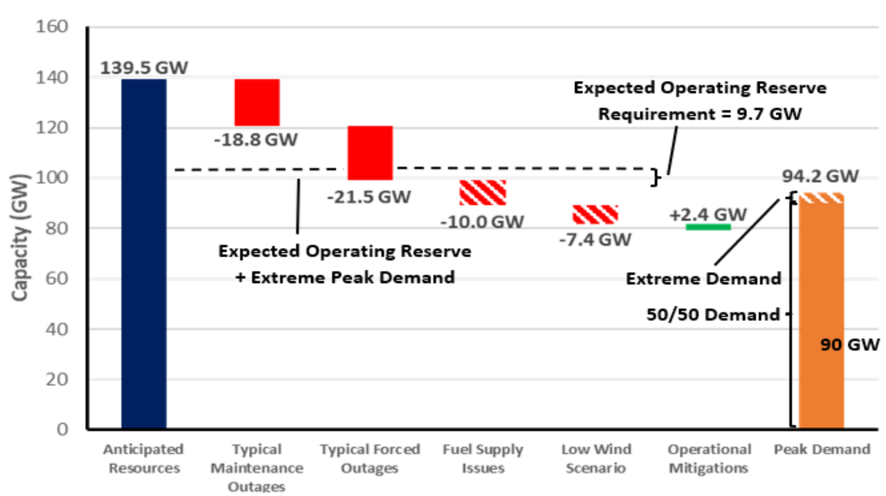
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal winter peak load, and generator outages from freezing or fuel supply issues, or low wind output could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely.

On-Peak Fuel Mix



2024–2025 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

Low Wind Scenario: Below-average wind contributions

Fuel Supply Issues: Derates and outages reflecting fuel supply issues during Winter Storm Elliott

Extreme Low-Generation: Maximum historical generation observed over past 5 years

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

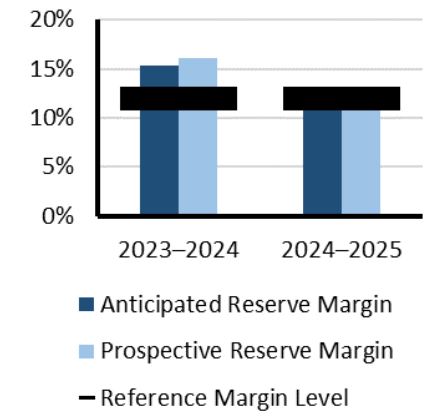
MRO-Manitoba Hydro

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 608,500 electricity customers in Manitoba and provides approximately 293,000 customers with natural gas in southern Manitoba. Electricity is supplied predominantly from hydroelectric generation. The service area is the province of Manitoba, which is 251,000 square miles within MISO's RC area. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is winter peaking.

Highlights

- Manitoba Hydro's ARM for Winter 2024–2025 is close to its 12% RML. A 4% (200 MW) increase in peak demand forecast has caused ARM to fall.
- Manitoba Hydro expects to maintain system reliability by closely monitoring and adjusting planned outages if required over the winter season.
- Manitoba Hydro continues to monitor a number of issues, including potential for extreme weather events, drought, and issues related to asset health.

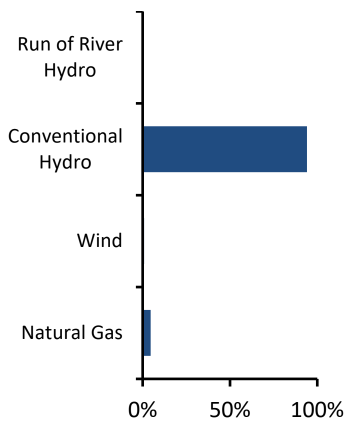
On-Peak Reserve Margin



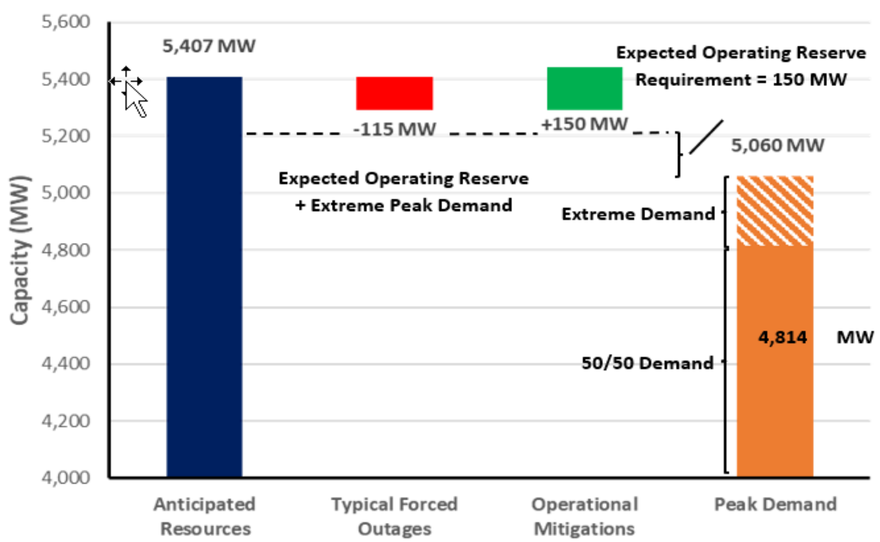
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely (see **Probability-Based Risk Assessment**).

On-Peak Fuel Mix



2024–2025 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

Operational Mitigations: Emergency operating procedures

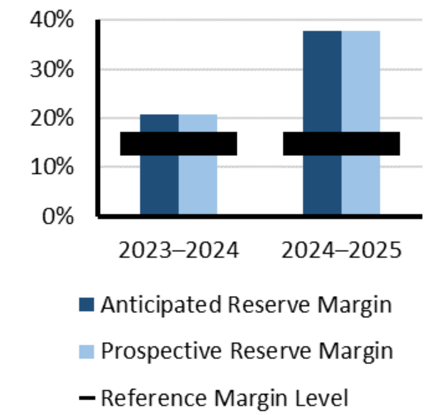
MRO-SaskPower

MRO-SaskPower is an assessment area in Canada's Saskatchewan province, which has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.2 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 Bulk Electric System (BES) and its Interconnections.

Highlights

- Saskatchewan experiences its peak load during the winter months due to extreme cold weather.
- Reserve margins are higher than the prior winter due to the addition of new generation facilities. Based on the planned maintenances, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during the 2024–2025 Winter.
- During extreme winter conditions, SaskPower would utilize available demand-response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions to manage the situation.

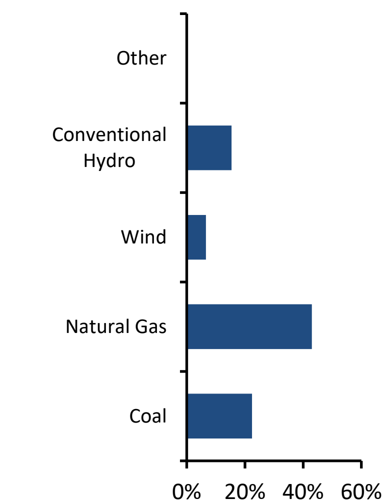
On-Peak Reserve Margin



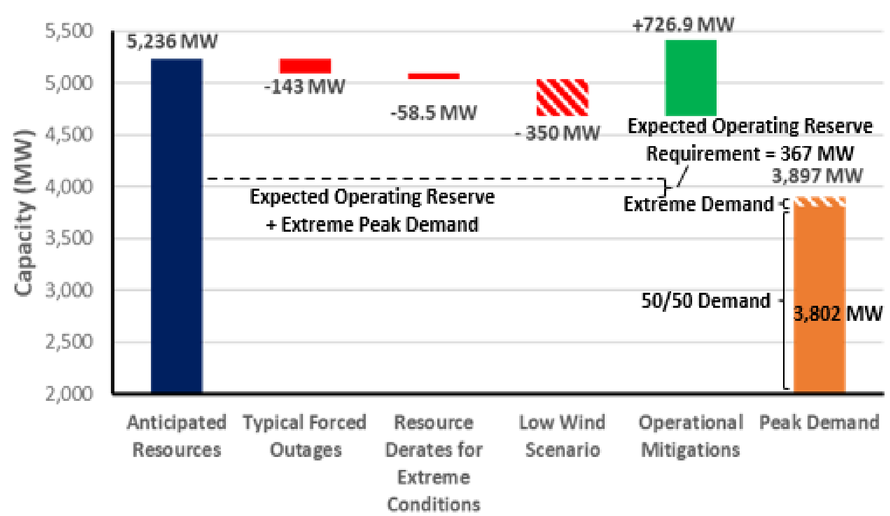
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely.

On-Peak Fuel Mix



2024–2025 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.

Maintenance Outages: Average of planned maintenance outages for the winter months, December–February, over the past three years

Forced Outages: Estimated using SaskPower forced outage model

Low Wind Scenario: Estimated using SaskPower forced outage model

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

SPP

The SPP PC 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 serves a population of more than 18 million.

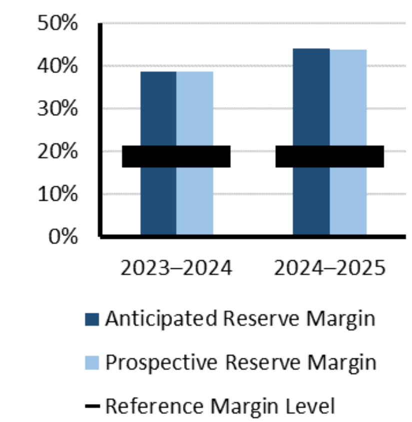
Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2024–2025 winter season but realizes that interruptions to fuel supply could create unique operational challenges.
- SPP continues to work with neighboring regions to address potential electric deliverability issues associated with extreme weather events. Efforts are aimed at enhancing communications and operator preparedness.
- SPP has implemented operational mitigation teams, processes, and procedures to support real-time reliability needs. Efforts are aimed at minimizing conservative operations and EEAs and responding to midrange wind forecast uncertainty.
- Coal transport could be an emerging reliability issue as SPP is observing lower coal stock at a number of plants because of issues related to the railroad system.

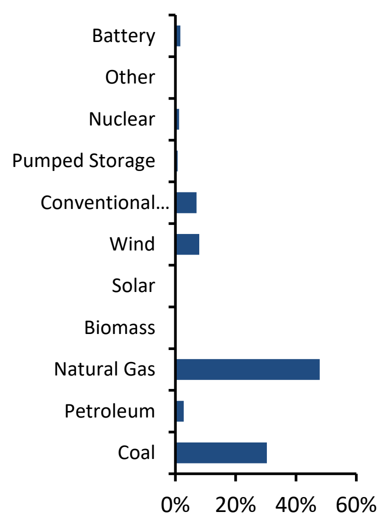
Risk Scenario Summary

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

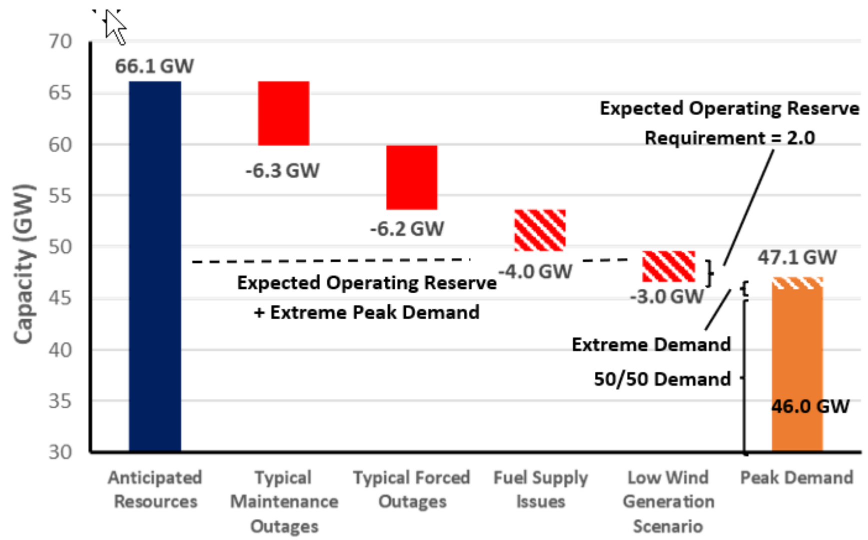
On-Peak Reserve Margin



On-Peak Fuel Mix



2024–2025 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: Based on MW capacity of gas-fired generators experiencing fuel supply issues in winter storm Elliott.

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

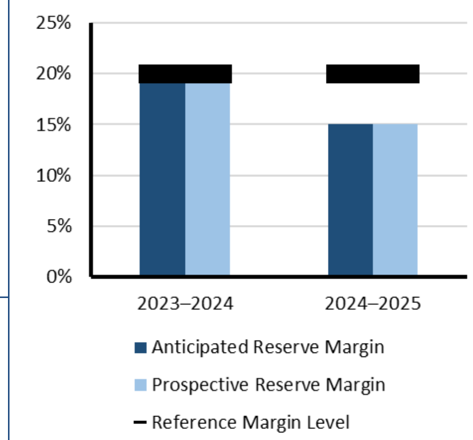
NPCC-Maritimes

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

Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, emergency operations and planning procedures are in place.
- Maritimes is forecasting a 5% (300 MW) increase in peak demand forecast with minor changes to installed capacity and net interchanges compared to last year. As a result, the ARM has decreased from 20% last year to 15% this year. Dual-fueled units will have sufficient supplies of heavy fuel oil on site to enable sustained operation in the event of natural gas supply interruptions.
- Maritimes has long-term energy contracts and can purchase energy day ahead and in real time as required.
- Maritimes has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual-fuel oil/gas, tie benefits, and biomass.

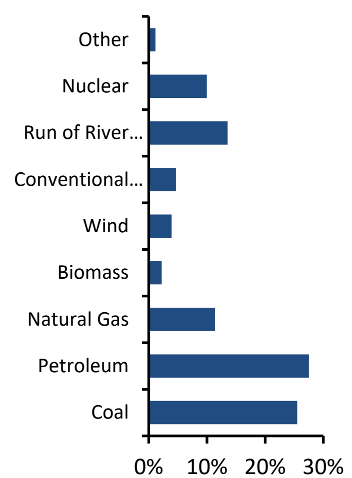
On-Peak Reserve Margin



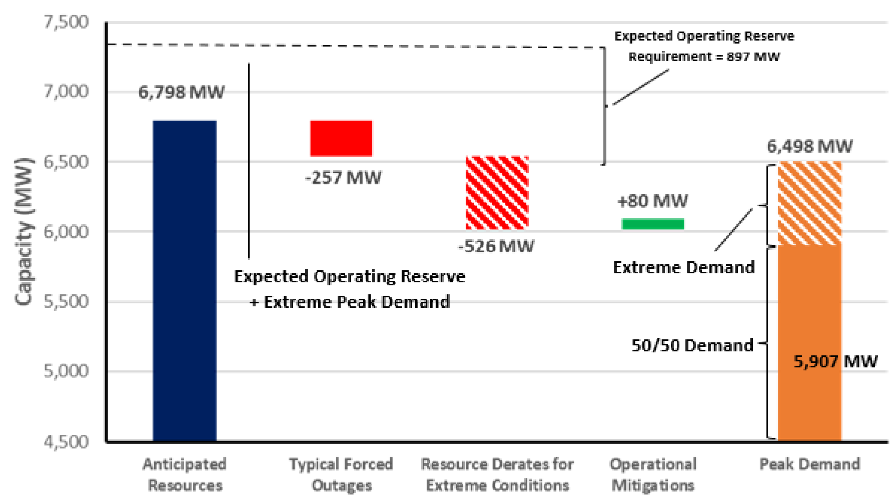
Risk Scenario Summary

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

On-Peak Fuel Mix



2024–2025 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Scenario peak load with adjustment calculated by adding a 10% margin of error to the peak internal demand forecast taken from the *Long-Term Reliability Assessment* (LTRA) for the 2024–2025 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2023)

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

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

NPCC-New England

NPCC-New England is an assessment area that is served by ISO-NE and consists of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

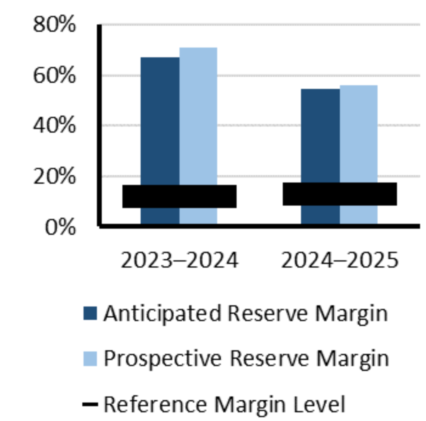
Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2024–2025 Winter operating period for a mild or moderate winter similar to 2021–2022 or 2017–2018. A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquefied natural gas (LNG)).
- Similar to Winter 2023–2024, ISO-NE is offering an interim program to compensate certain resource operators that provide fuel security. The Inventoried Energy Program (IEP) is a voluntary, interim program designed to provide incremental compensation for participants that maintain inventoried energy for their assets during extreme cold periods when winter energy security is most stressed.
- ISO-NE expects to have sufficient capacity resources to meet the 2024–2025 50/50 and 90/10 winter peak demand forecast of 20,308 MW and 21,089 MW for the weeks beginning January 5, 12, and 19.
- ISO-NE evaluates an above 90/10 scenario that captures the area's coldest day in the last 25 years while using both current and future load models. The above 90/10 winter peak demand forecast is 21,814 MW for the three previously identified peak weeks. ISO-NE currently has sufficient resources to meet this demand; however, a cold snap may require the region to rely on its external ties and emergency procedures to operate reliably.

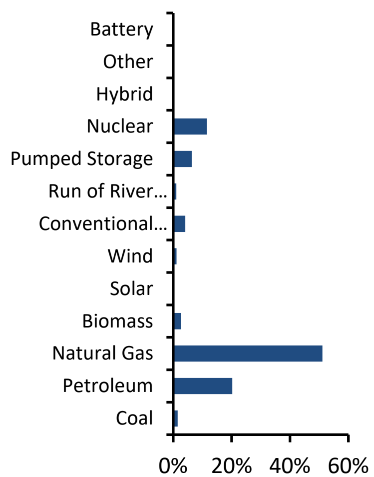
Risk Scenario Summary

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

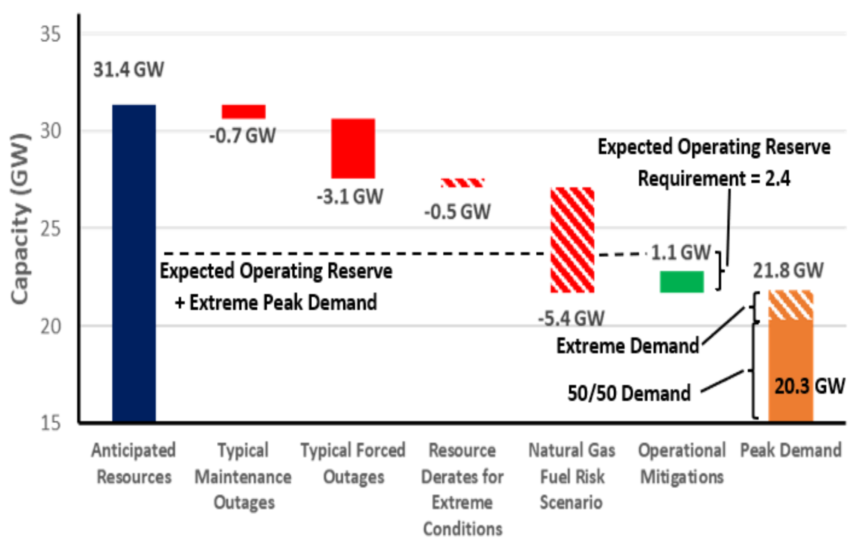
On-Peak Reserve Margin



On-Peak Fuel Mix



2024–2025 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 for coldest day from the last 25 years

Maintenance and Forced Outages: Based on weekly averages

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

Operational Mitigations: Based on 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 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 2024–2025 IRM at 22.0%.

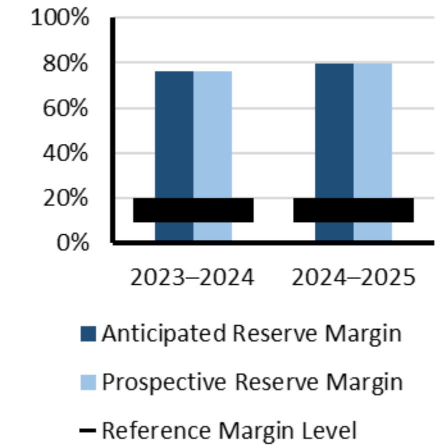
Highlights

- New York is a summer-peaking area, and no emerging reliability issues are anticipated during the 2024–2025 winter assessment period. Surplus capacity margins above NYISO's operating reserve requirements are projected.

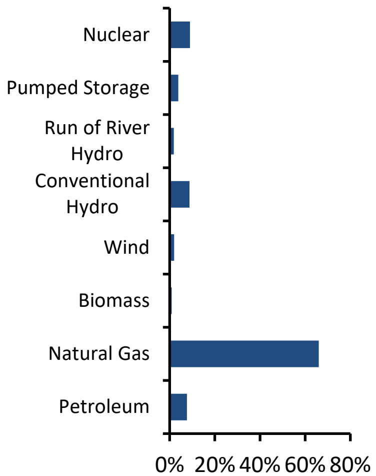
Risk Scenario Summary

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.

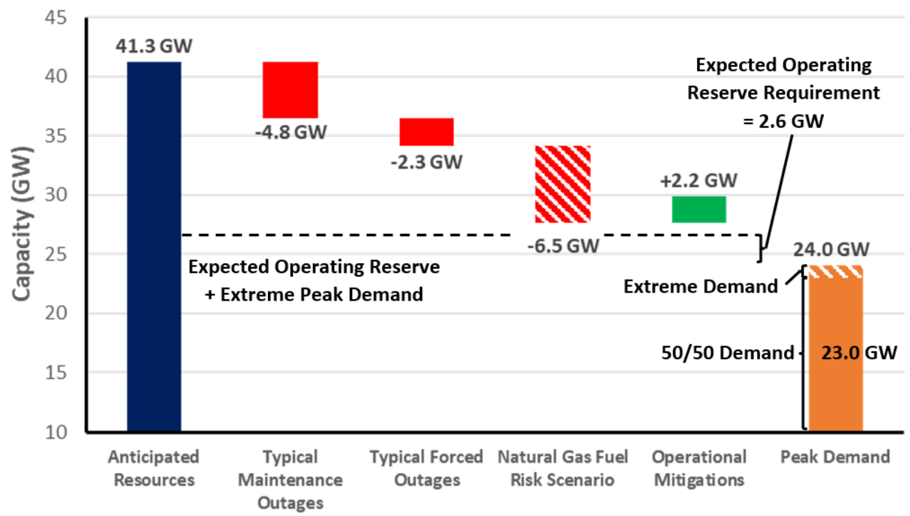
On-Peak Reserve Margin



On-Peak Fuel Mix



2024–2025 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 Scenario: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather. Based on a 2023 analysis, approximately 6,518 MW of gas generation with non-firm fuel supplies could be unavailable.

Operational Mitigations: Based on NYISO operating procedures

NPCC-Ontario

NPCC-Ontario is an assessment area 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 more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

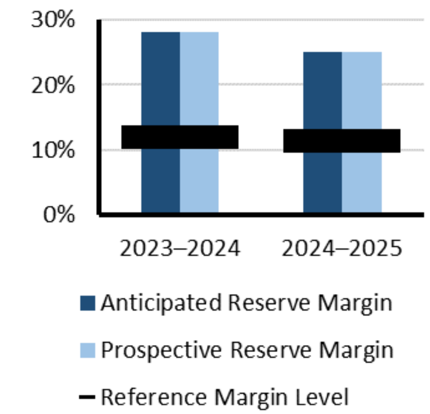
Highlights

- IESO expects that the electricity system will remain reliable with reserve margins well above required levels. Operators and forecasters work closely with neighboring jurisdictions to manage any extreme weather events.
- Generator 1 of the Pickering Nuclear Generating Station was removed from service at the end of September 2024. Generator 4 is scheduled to be removed from service at the end of December 2024. IESO's September 2024 Reliability Outlook shows reserves above requirement (RAR) of greater than 1,930 MW for the months of December 2024 to February 2025.The two nuclear unit retirements at the Pickering Nuclear Generating Station have been anticipated for some time and the system is adequate in both normal and extreme weather even considering these shutdowns.
- As a summer-peaking province, there is lower risk of reliability issues during the winter. Ontario regularly experiences extreme cold weather; as such, the thermal generators are reliably supplied by natural gas pipelines whose close proximity to the Dawn Hub storage facility significantly reduces deliverability and reliability concerns.
- The 2023 capacity auction secured 1,310 MW of capacity for the Winter 2024–2025 season, which on its own represents 54% of the RAR.

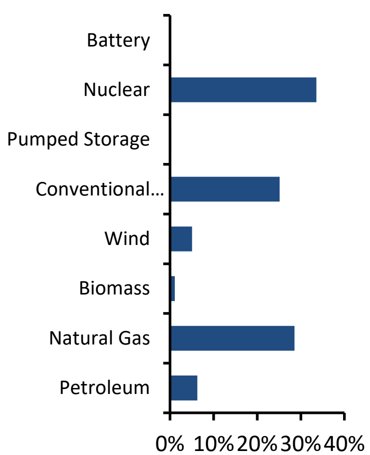
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

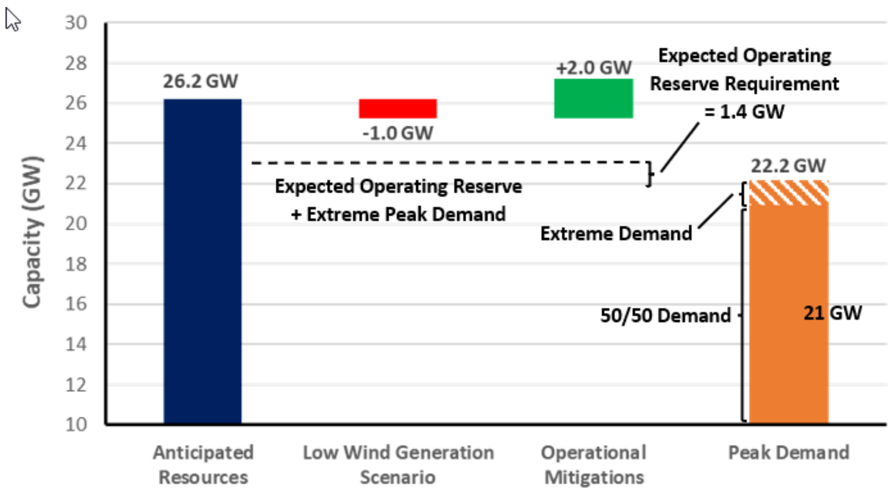
On-Peak Reserve Margin



On-Peak Fuel Mix



2024–2025 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

Operational Mitigations: Imports anticipated from neighbors during emergencies

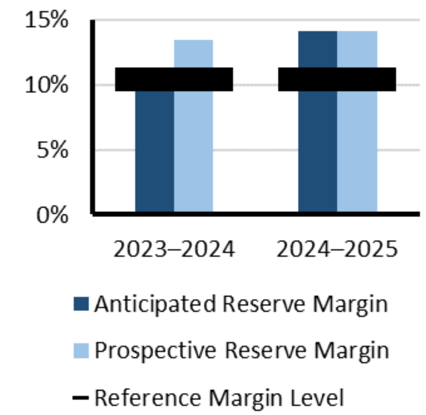
NPCC-Québec

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

Highlights

- Québec predicts that it will maintain system resource adequacy this winter.
- Québec projects that it will maintain adequate capacity margins above its reference reserve requirements for the 2024–2025 Winter assessment period.
- No changes have been made to Québec's winter preparedness programs.
- HydroQuébec is reporting a higher value in demand response for the upcoming winter compared to last winter. The value reflects some growth in demand response but is mainly due to a better characterization of existing programs.

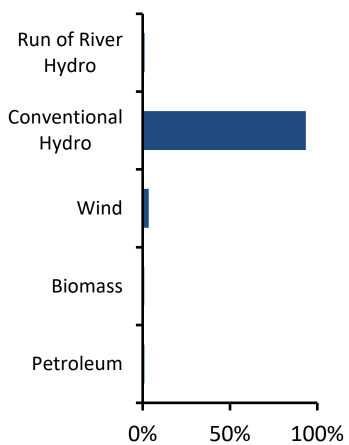
On-Peak Reserve Margin



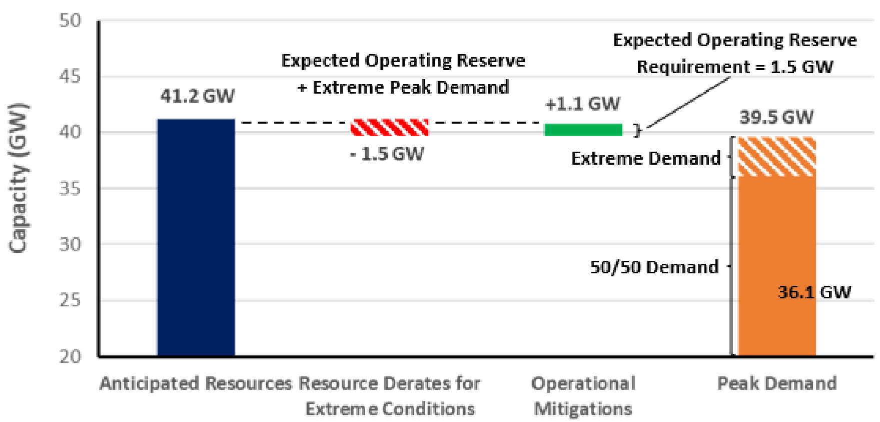
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Fuel Mix



2024–2025 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: The extreme load forecast is determined at two standard deviations higher than the mean, which has a 6.06% probability of occurrence. No changes are expected to demand-side resources in extreme conditions.

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

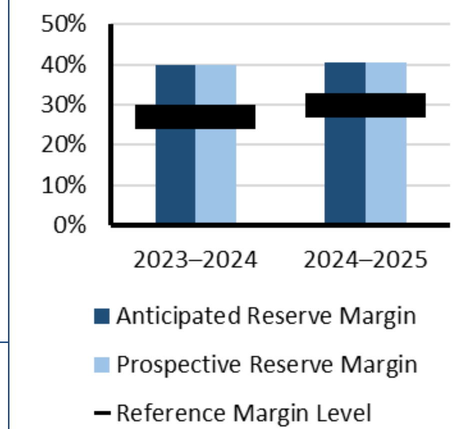
PJM

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

Highlights

- PJM expects no resource problems over the entire 2024–2025 Winter peak season because its installed capacity is significantly higher (10 percentage points) than its reserve requirement.
- Since 44% of capacity associated with the Transco Regional Energy Access (REA) natural gas pipeline project is used by PJM natural-gas-fired generation, a potential shut-in of the new REA facilities presents a significant reliability risk going into the winter season. Nearly 20 GW of natural gas-fired generation in the far eastern Pennsylvania/New Jersey/Delaware area has either direct or indirect (via natural gas local distribution company) access to this new capacity.

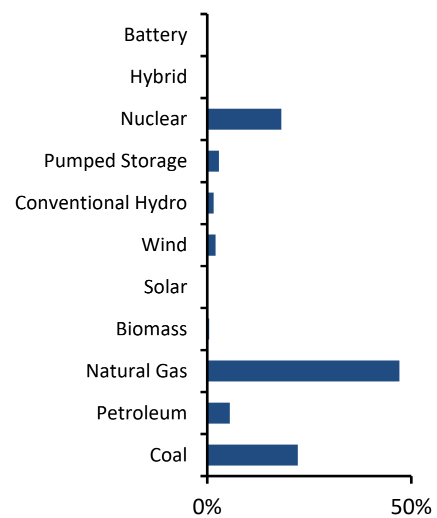
On-Peak Reserve Margin



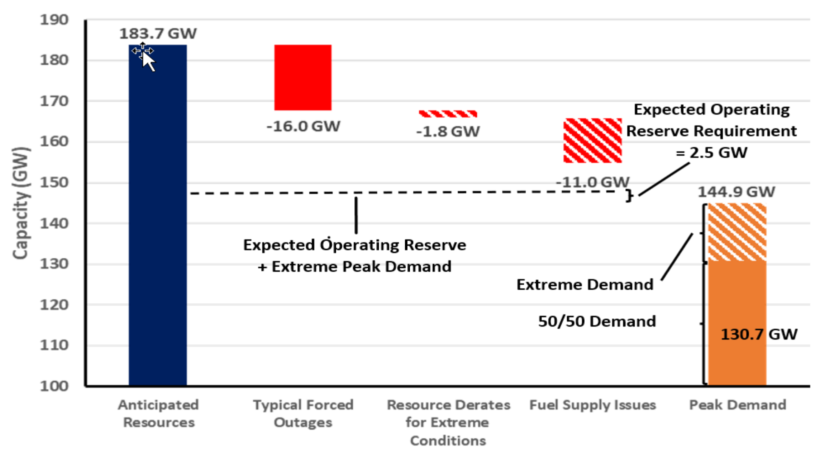
Risk Scenario Summary

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

On-Peak Fuel Mix



2024–2025 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

Fuel Supply Issues: Additional outages and derates equal to the MW capacity affected by natural gas production and supply issues during Winter Storm Elliott in 2022.

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.

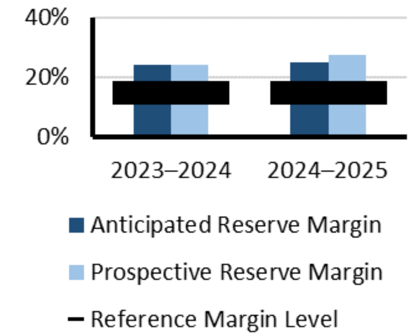
Highlights

- The ARM for the SERC-East assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- Three units on pre-season outage totaling 1,583 MW have return-to-service dates in December. If these units are delayed, it will reduce the amount of generation available for this winter-peaking region.
- The entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation. As utilities move away from coal, it can become more difficult to source coal. There are no immediate concerns with coal supplies for the upcoming winter.
- To reduce the risk of firm load shed under extreme conditions, the entities participate in reserve sharing groups and some do not assume the availability of external resources beyond reserve sharing groups.

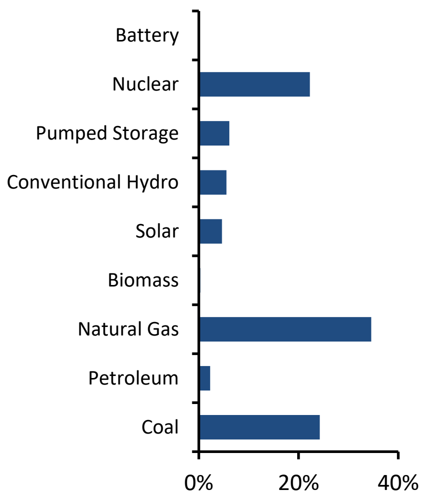
Risk Scenario Summary

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

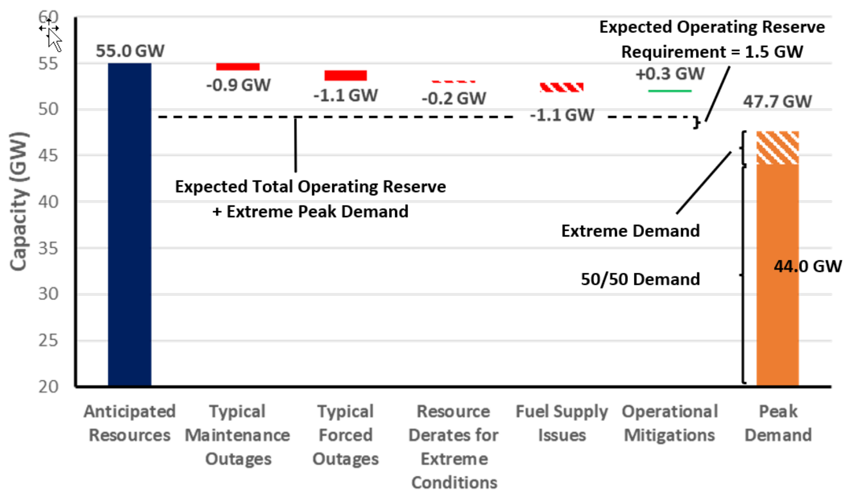
On-Peak Reserve Margin



On-Peak Fuel Mix



2024–2025 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 2022–2024)

Fuel Supply Issues: Additional outages and derates equal to the MW capacity affected by natural gas production and supply issues during Winter Storm Elliott in 2022.

Operational Mitigations: A total of 0.4 GW based on operational/emergency procedures

SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six 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.

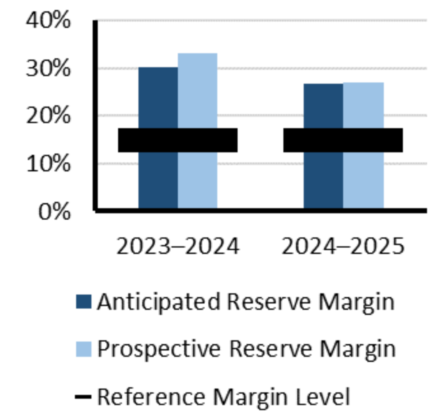
Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Central assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- Entities in SERC-Central have implemented enhanced operating plans and generator weatherization programs to reduce winter reliability risks. Improved communications protocols, checklists for cold weather preparations for the BA, RC, and TOP functions, and a process to expedite obtaining environmental permit waivers from the Department of Energy (DOE) in emergency conditions are in place. In the aftermath of Winter Storm Elliott, natural gas pipeline and generator logic changes have been implemented that are expected to mitigate the risk of repeated pressure-related outages at generating units.
- To reduce the risk of firm load shed under extreme conditions, operators coordinate with counterparts in neighboring areas on emergency energy agreements and calculate the amount of emergency imports or exports that will be available during EEA2 or higher events.

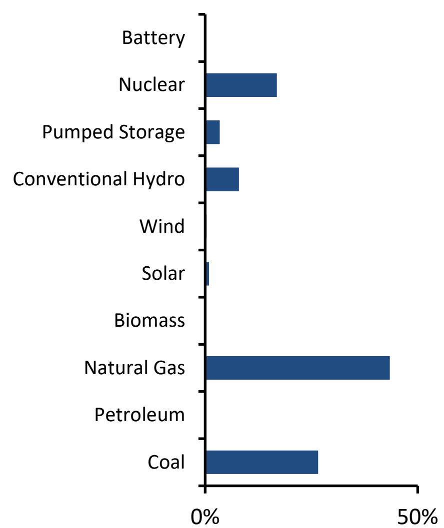
Risk Scenario Summary

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

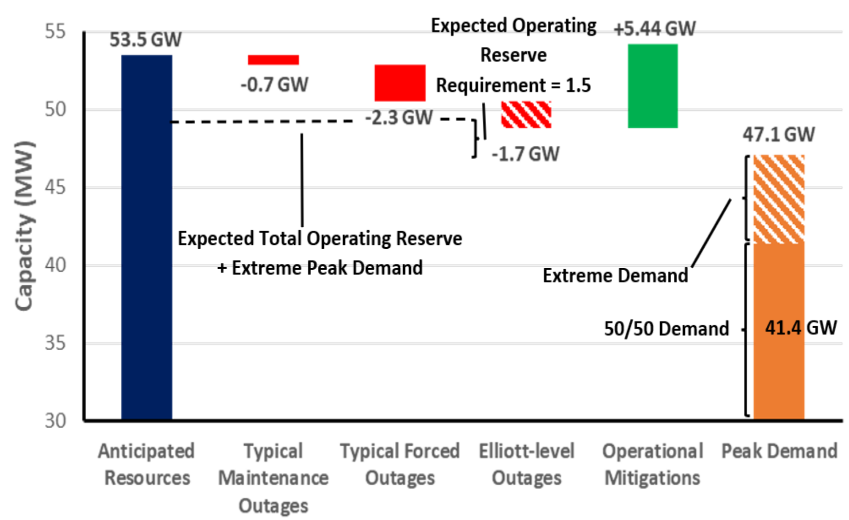
On-Peak Reserve Margin



On-Peak Fuel Mix



2024–2025 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

Fuel Supply Issues Additional outages and derates equal to the MW capacity affected by natural gas production and supply issues during Winter Storm Elliott in 2022.

Operational Mitigations: A total of over 5 GW based on operational/emergency procedures

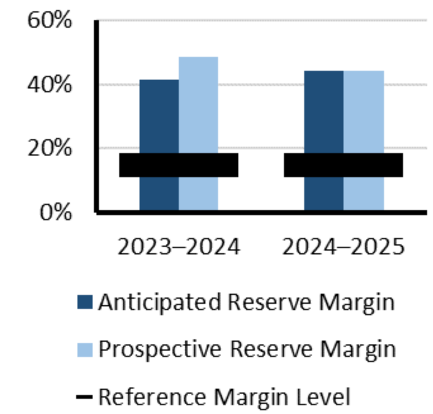
SERC-Southeast

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

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Southeast assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- Increased natural gas consumption and higher pipeline utilization rates could result in emerging or potential reliability issues for the upcoming winter season as peaking natural-gas-fired generators face increased competition for delivered gas and potential low gas pressures.
- To reduce the risk of firm load shed under extreme conditions, one entity participates in planning collaboratives with neighboring entities within the BA and neighboring BAs that coordinate reliability studies and initiatives.

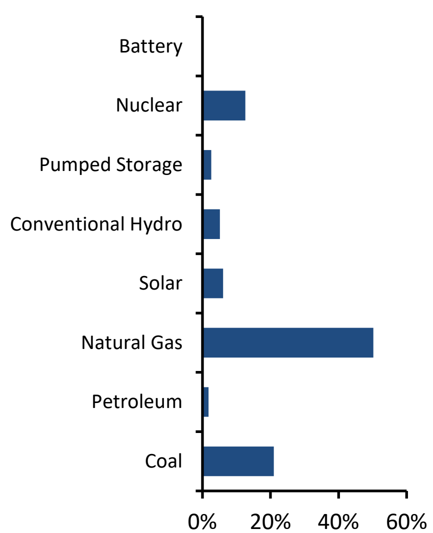
On-Peak Reserve Margin



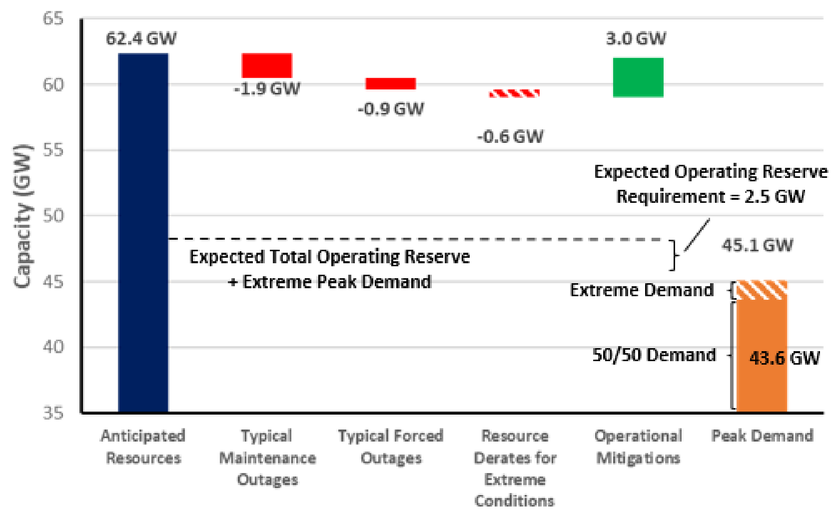
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024–2025 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

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

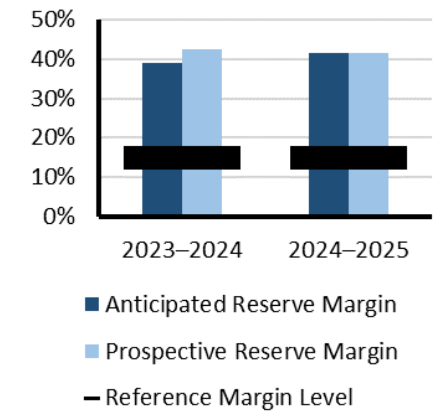
SERC-Florida Peninsula

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

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Florida-Peninsula assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- The entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- To reduce the risk of firm load shed under extreme conditions, entities participate in coordinated studies, including bi-directional seasonal studies with the neighboring RC, although they do not rely on any non-firm external assistance under extreme conditions.

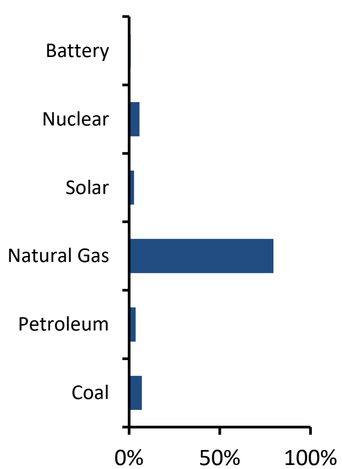
On-Peak Reserve Margin



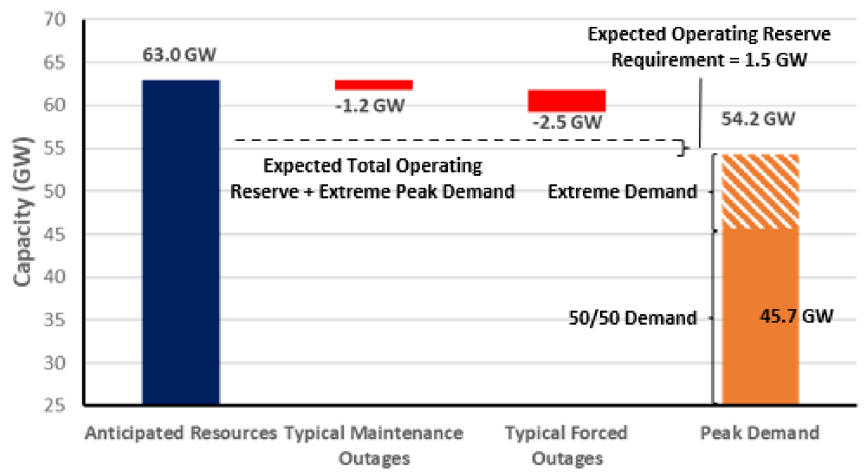
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024–2025 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

Texas RE-ERCOT

ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas power grid.

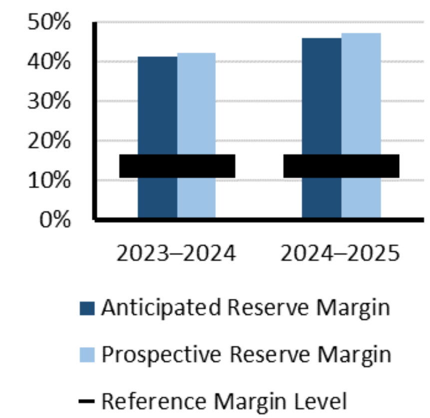
Highlights

- Given an ARM of 46.1% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for the winter peak load hour (hour ending 8:00 a.m.) given expected normal system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the January forecasted winter peak load day. The highest EEA risk hour is the hour ending 8:00 a.m., corresponding to the peak load hour.
- A contributor to the reserve scarcity risk is the potential need, under certain grid conditions, to limit power transfers from South Texas into the San Antonio region. Conditions could cause overloads on the lines that make up the South Texas export and import interfaces, necessitating South Texas generation curtailments and potential firm load shedding to avoid cascading outages. The risk is greatest when the Texas RE-ERCOT area has high net loads and high forced outages for thermal power plants.
- ERCOT does not expect any significant fuel supply issues for the winter.
- ERCOT completed 340 generation resource and 129 TSP winter weatherization inspections during last winter, which brings the cumulative completed winter inspections to 2,117, well above ERCOT's goal of 1,400 inspections.

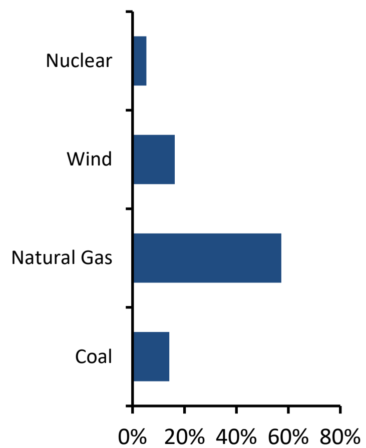
Risk Scenario Summary

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

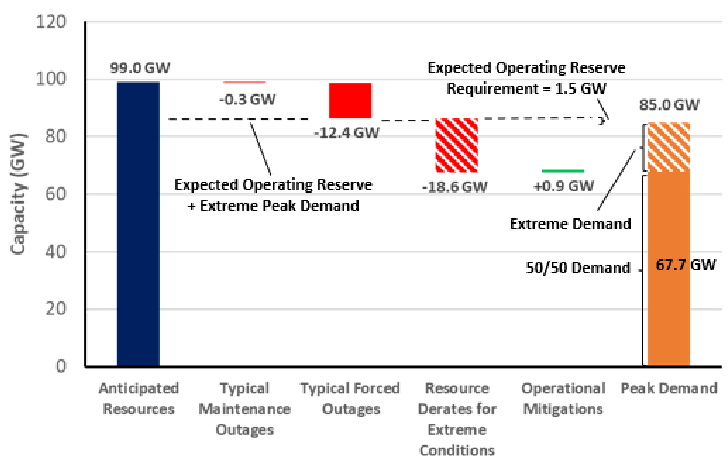
On-Peak Reserve Margin



On-Peak Fuel Mix



2024–2025 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Maintenance Outages: Based on historical winter data and consideration of 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 due to the implementation of the PUCT's weatherization standards.

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

Operational Mitigations: Additional potential capacity from switchable generation and imports

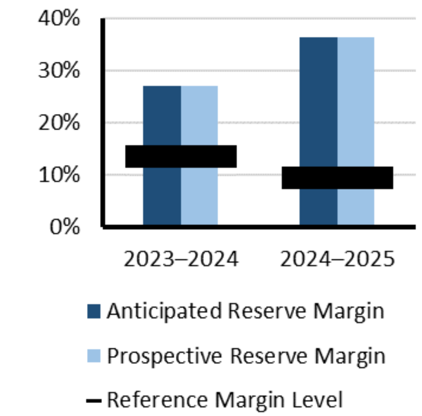
WECC-Alberta

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 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-Alberta is anticipated to have adequate resources for all expected winter and extreme energy availability and demand scenarios.
- Northern Alberta is expected to see mild winter temperatures and be dry while southern Alberta is expected to be cool and wet this winter.
- Alberta added 63 MW of new battery energy storage, 2,730 MW of new natural gas, almost 700 MW of solar, and over 1,300 MW of new wind capacity since last winter. By the end of 2024, Alberta plans to add 80 MW of battery energy storage, 200 MW of natural gas, and over 1,800 MW of additional solar.
- Despite low resource adequacy risk, maintaining sufficient frequency response capability has been identified as an operational risk in the Alberta system. Frequency response has been declining due to the increasing share of IBR resources and declining baseload resources. Under-frequency load shedding risk is highest when the Alberta system is insulated, or near-insulated, from the Western Interconnection.

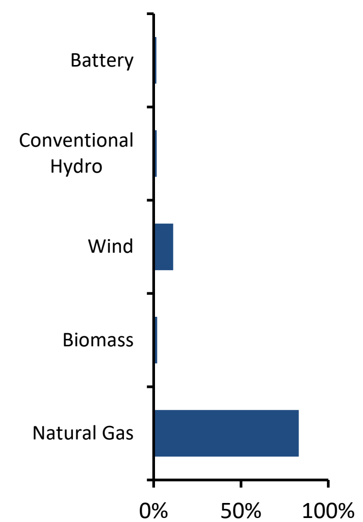
On-Peak Reserve Margin



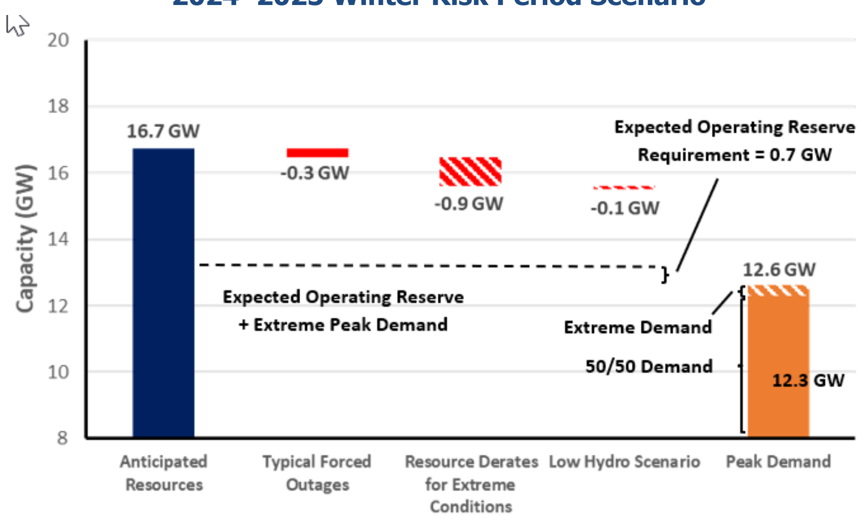
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Fuel Mix



2024–2025 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"

Low Hydro Scenario: Estimated derate for lower hydro output

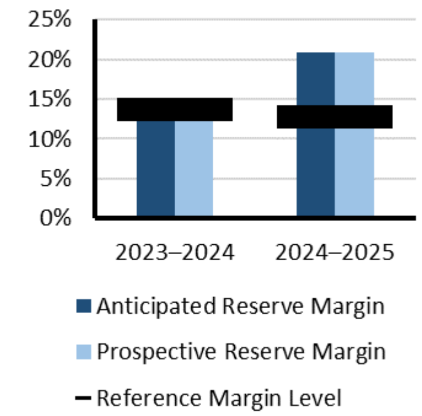
WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of BC, 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 US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-BC is anticipated to have adequate resources for anticipated winter conditions. If peak demand exceeds normal forecasts and hydroelectric generation is lower than normal, non-firm imports are likely to be needed to meet required operating reserves.
- Southern BC is expected to be colder and dryer than normal while northern BC is expected to be milder and wetter.
- BC plans to add 190 MW of additional conventional hydro and 7 MW of winter wind capacity (29 MW nameplate) by the end of 2024.

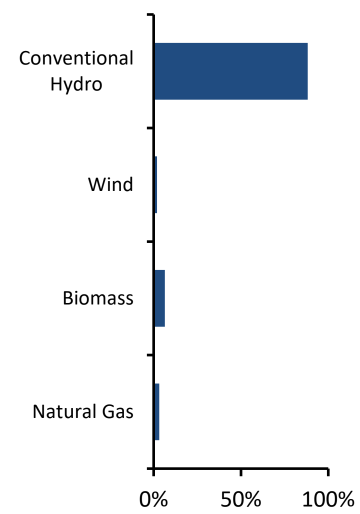
On-Peak Reserve Margin



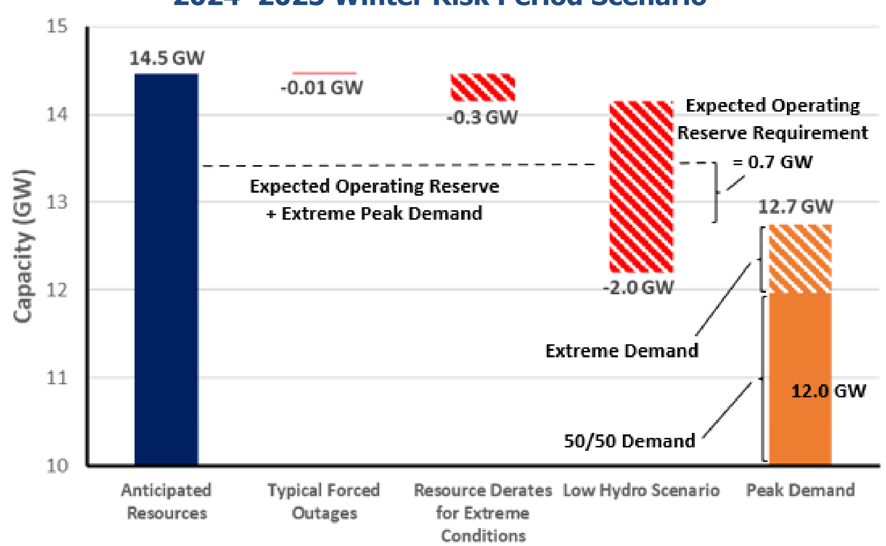
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios.

On-Peak Fuel Mix



2024–2025 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"

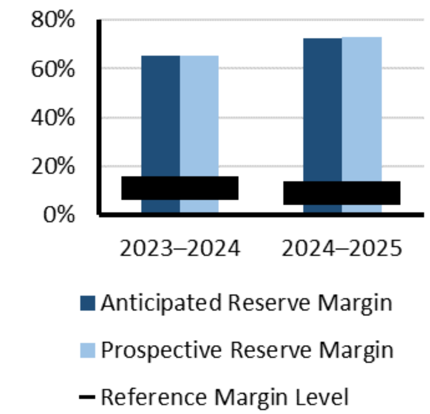
Low Hydro Scenario: Estimated derate for lower hydro output

WECC-California/Mexico

WECC-California/Mexico (CA/MX) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. 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 US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

- CA/MX will meet all operating reserve margins before imports in all winter resource availability scenarios.
- NOAA's weather models (as of August 15) predict average winter temperatures for CA/MX. NOAA's Precipitation models predict below-average precipitation in Southern California.
- CA/MX plans to add 4,600 MW of new battery energy storage before winter along with 46 MW of natural gas, over 3,800 MW of new solar with a winter capacity of over 1,000 MW, and 320 MW of new wind with a winter capacity of almost 90 MW.

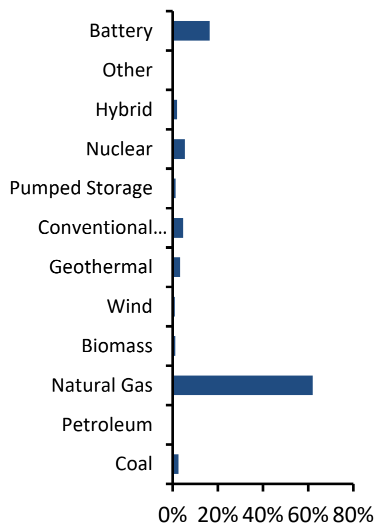
On-Peak Reserve Margin



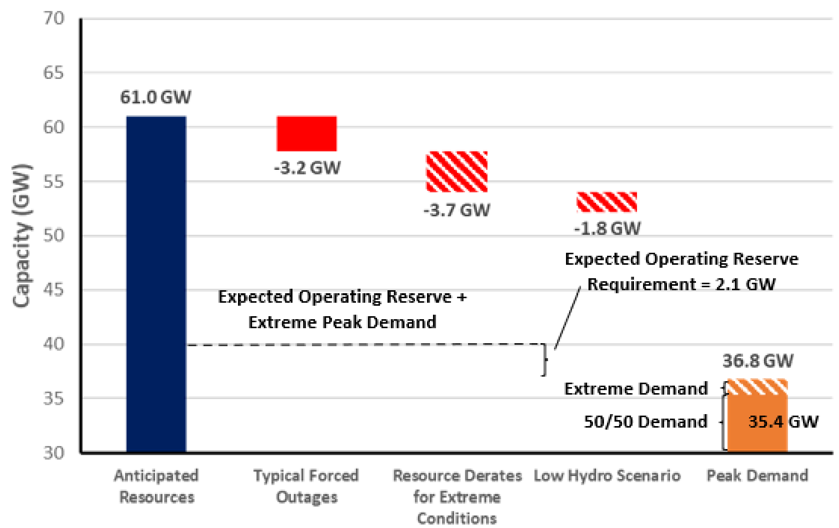
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024–2025 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"

Low Hydro Scenario: Estimated derate for lower hydro output

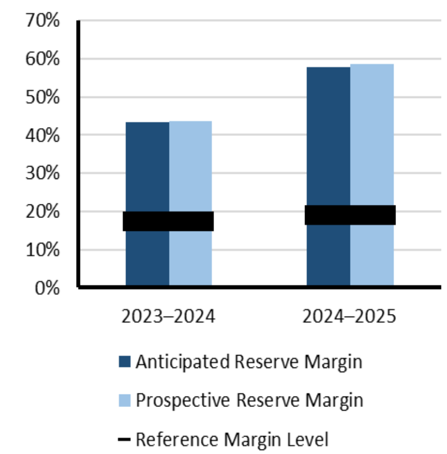
WECC-Northwest

WECC-Northwest is a summer-peaking assessment area in the WECC Regional Entity that includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming, and parts of California, Nebraska, Nevada, and South Dakota. 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 US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-Northwest is anticipated to have adequate resources for all expected and extreme energy availability and demand scenarios this winter.
- NOAA's weather models (as of August 15) predict below-average winter temperatures for the Pacific Northwest (PNW), including Washington, Oregon, Idaho, and northern Montana. NOAA's Precipitation models predict above-average rainfall in the PNW, including Washington, northwest Oregon, northern Idaho, and western Montana, and below-average precipitation in Nevada, Utah, Colorado, Arizona, New Mexico, and Texas.
- WECC-Northwest has added 627 MW of new battery energy storage, 300 MW of new conventional hydro and 300 MW of new wind, 74 MW of geothermal, 1,665 MW of natural gas, and 1,653 MW of solar since last winter. By the end of 2024, WECC-Northwest is planning to add another 135 MW of battery energy storage and 350 MW of solar.

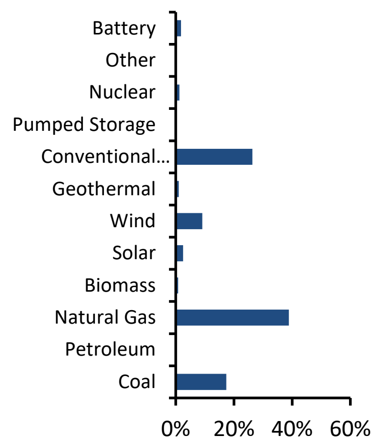
On-Peak Reserve Margin



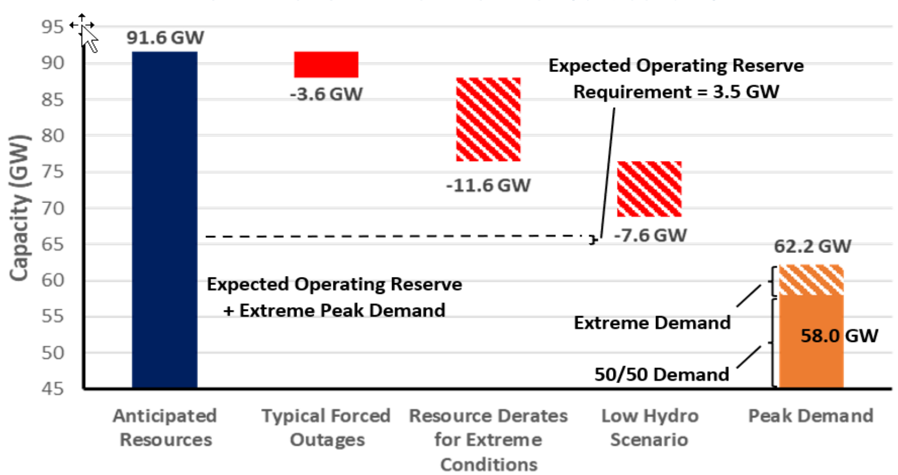
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024–2025 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"

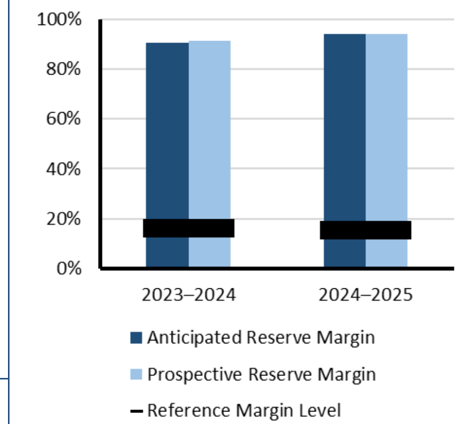
Low Hydro Scenario: Estimated derate for lower hydro output

WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the WECC Regional Entity that includes Arizona, New Mexico, and parts of California and Texas. 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 US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

- WECC-Southwest is anticipated to have adequate resources for all expected and extreme energy availability and demand scenarios this winter.
- NOAA's weather models (as of August 15) predict above-average winter temperatures in the Southwest for Arizona, New Mexico, and Texas. Precipitation models predict below-average precipitation in the Southwest, including Nevada, Utah, Colorado, Arizona, New Mexico, and Texas.
- WECC-Southwest has added almost 1,600 MW of new battery energy storage, 99 MW of natural gas, over 2,600 MW of winter capacity solar, and 216 MW of wind since last winter. By the end of 2024, the SW is planning to add another 120 MW of battery energy storage and 64 MW of solar.

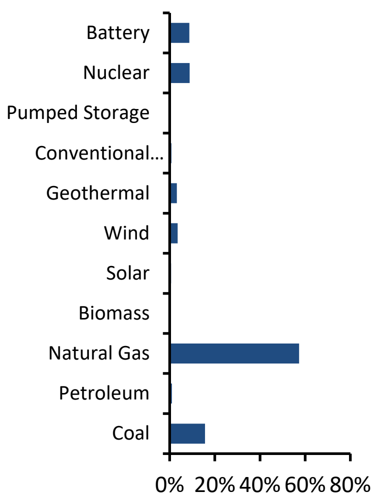
On-Peak Reserve Margin



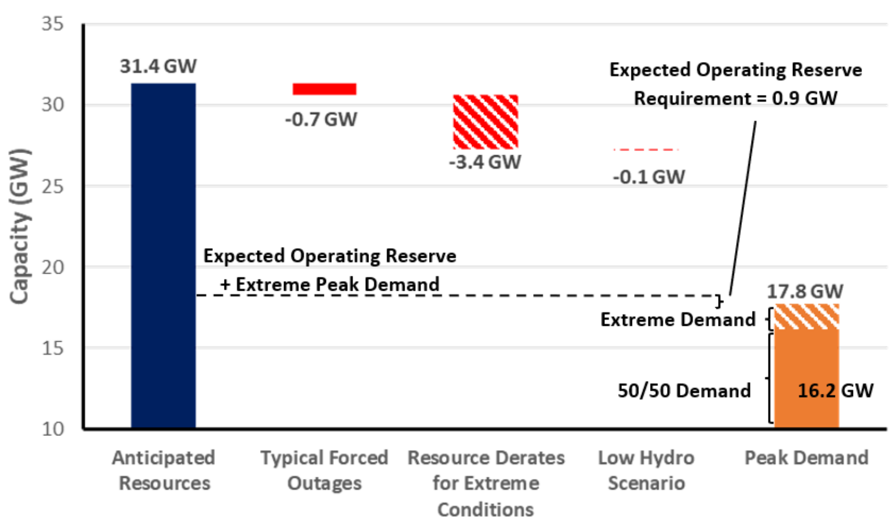
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024–2025 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"

Low Hydro Scenario: Estimated derate for lower hydro output

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• The reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity 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.
• *2024 Long-Term Reliability Assessment* data has been used for most of this 2024–2025 assessment period augmented by updated load and capacity data provided by Regional Entities and assessment areas.
• 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[6] or total internal demand for the summer and winter of each year.[7]
• Total internal demand projections are based on normal weather (50/50 distribution[8]) and are provided on a coincident[9] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

[6] *Glossary of Terms* used in NERC Reliability Standards
[7] The summer season represents June–September and the winter season represents December–February.
[8] 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.
[9] 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 and FRCC calculate total internal demand on a noncoincidental basis.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit 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.

Prospective Resources: This 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 RM: 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, Independent System Operator/Regional Transmission Organization (ISO/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 (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table 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, 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.[10] 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 2024 winter as shown in **Figure 4**.

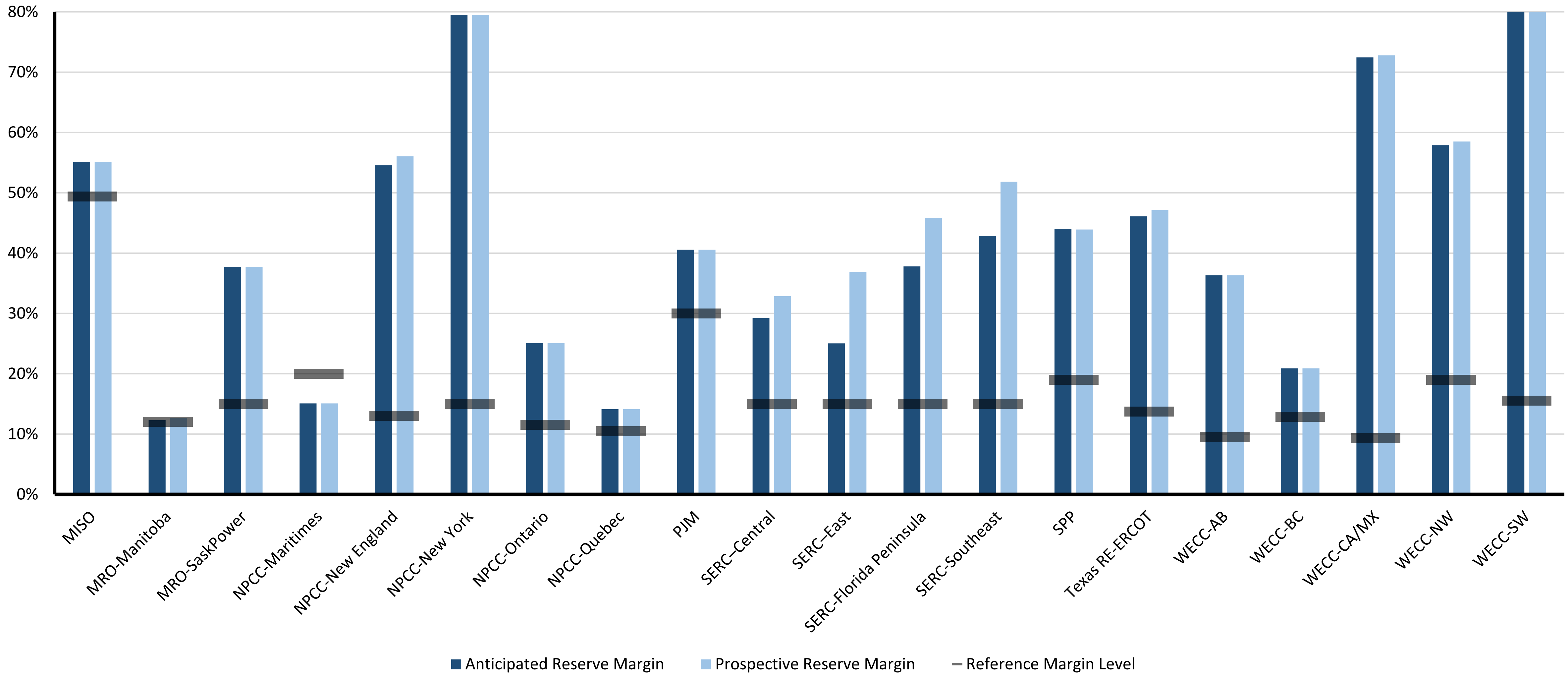


Figure 4: Winter 2024–2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[10] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2023–2024 winter to the 2024–2025 winter. Note that the RML is unchanged for areas that do not have a 2023–2024 RML shown. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC have noticeable reductions in anticipated resources between the 2023–2024 Winter and the 2024–2025 Winter. All areas except NPCC-Maritimes remain above their RMLs for 2024–2025 winter. NPCC-Québec is marginally above its RML. The lower ARMs for MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC do not result in reliability concerns during expected conditions for this upcoming winter. The Canadian winter-peaking systems of MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes, and NPCC-Québec have reserve margins that are near RMLs but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the **Data Concepts and Assumptions** section.

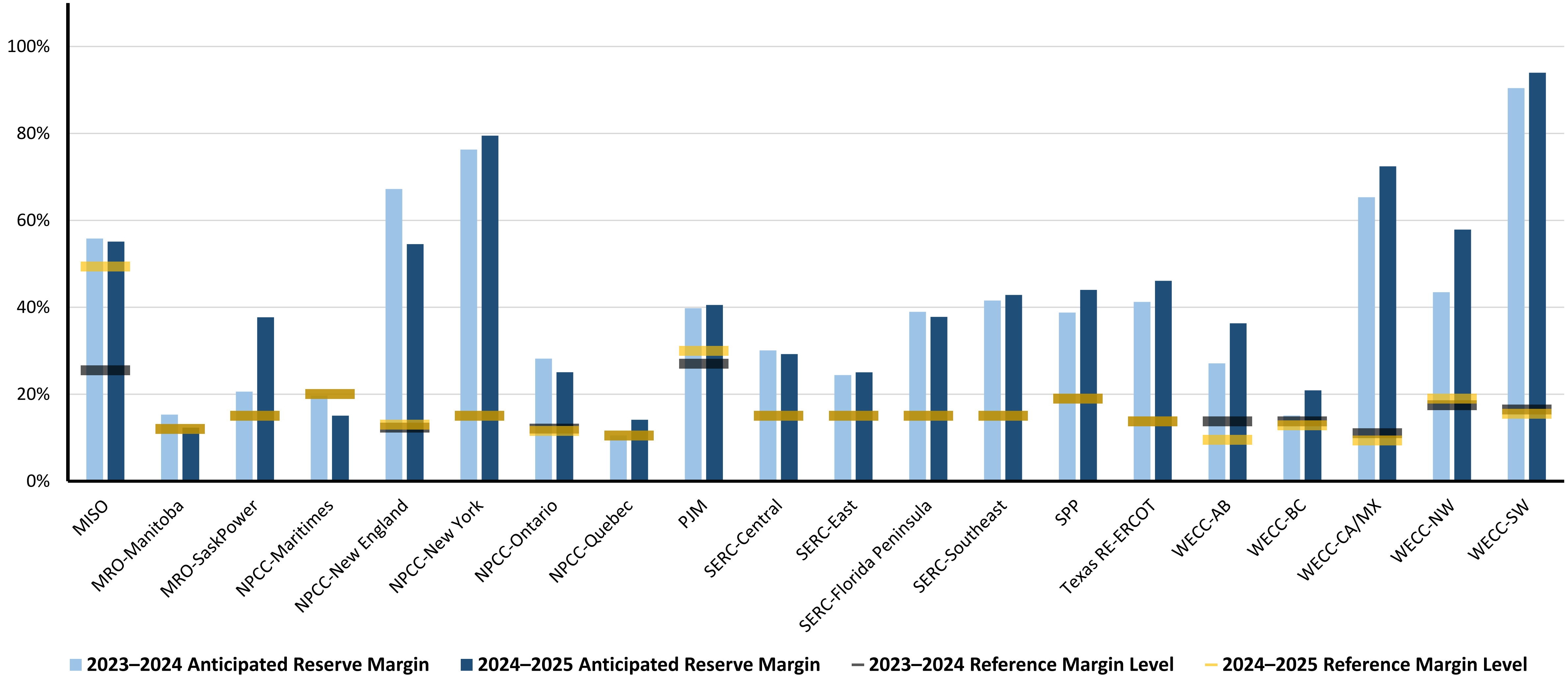


Figure 5: Winter 2023–2024 and Winter 2024–2025 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in **Figure 6**.[11] Assessment areas develop these forecasts based on historic 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.

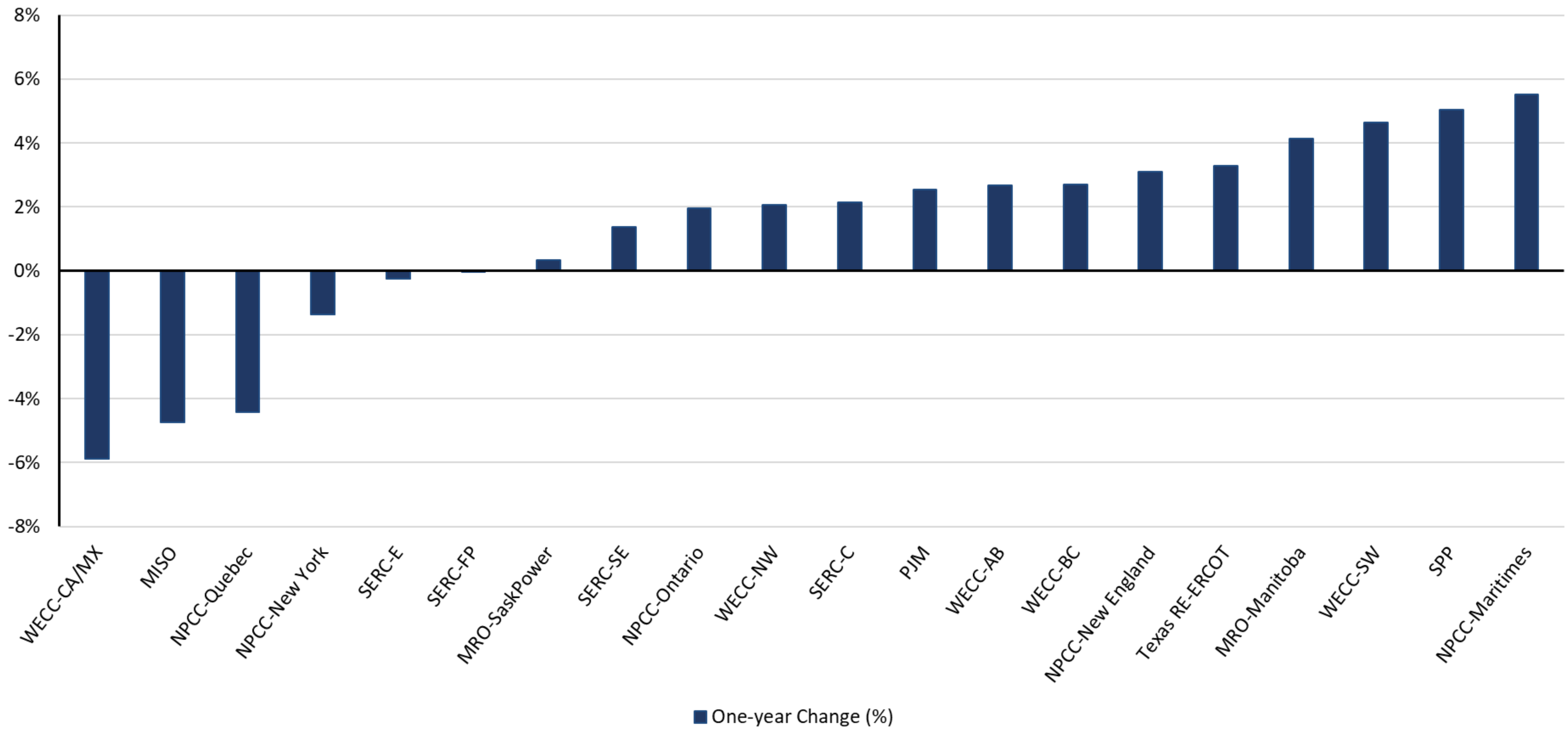


Figure 6: Change in Net Internal Demand—Winter 2023–2024 Forecast Compared to Winter 2024–2025 Forecast

[11] 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 are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,075	96,134	-5.8%
Demand Response: Available	7,681	6,219	-19.0%
Net Internal Demand	94,394	89,915	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	146,976	137,034	-6.8%
Tier 1 Planned Capacity	0	122	0
Net Firm Capacity Transfers	121	2,310	1810.7%
Anticipated Resources	147,097	139,466	-5.2%
Existing-Other Capacity	2,614	0	-100.0%
Prospective Resources	153,003	139,468	-8.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	55.8%	55.1%	-0.7
Prospective Reserve Margin	62.1%	55.1%	-7.0
Reference Margin Level	25.5%	49.4%	23.9

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,623	4,814	4.1%
Demand Response: Available	0	0	n/a
Net Internal Demand	4,623	4,814	4.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,864	5,924	1.0%
Tier 1 Planned Capacity	90	10	-88.8%
Net Firm Capacity Transfers	-622	-527	-15.3%
Anticipated Resources	5,332	5,407	1.4%
Existing-Other Capacity	36	18	-50.0%
Prospective Resources	5,368	5,425	1.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.3%	12.3%	-3.0
Prospective Reserve Margin	16.1%	12.7%	-3.4
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,839	3,852	0.3%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,789	3,802	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,320	4,946	14.5%
Tier 1 Planned Capacity	0	0	n/a
Net Firm Capacity Transfers	250	290	16.0%
Anticipated Resources	4,570	5,236	14.6%
Existing-Other Capacity	0	0	n/a
Prospective Resources	4,570	5,236	14.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.6%	37.7%	17.1
Prospective Reserve Margin	20.6%	37.7%	17.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	5,863	6,167	5.2%
Demand Response: Available	264	259	-1.8%
Net Internal Demand	5,599	5,907	5.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,622	6,647	0.4%
Tier 1 Planned Capacity	0	6	n/a
Net Firm Capacity Transfers	81	145	79.5%
Anticipated Resources	6,703	6,798	1.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,703	6,798	1.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.7%	15.1%	-4.6
Prospective Reserve Margin	19.7%	15.1%	-4.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,269	20,651	1.9%
Demand Response: Available	570	343	-39.8%
Net Internal Demand	19,699	20,308	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	31,795	30,030	-5.6%
Tier 1 Planned Capacity	187	194	4.0%
Net Firm Capacity Transfers	958	1,161	21.1%
Anticipated Resources	32,940	31,385	-4.7%
Existing-Other Capacity	201	306	52.0%
Prospective Resources	33,641	31,691	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	67.2%	54.5%	-12.7
Prospective Reserve Margin	70.8%	56.1%	-14.7
Reference Margin Level	12.3%	13.0%	0.7

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,402	21,867	2.2%
Demand Response: Available	853	915	7.3%
Net Internal Demand	20,549	20,951	2.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,301	26,652	1.3%
Tier 1 Planned Capacity	24	0	-100.0%
Net Firm Capacity Transfers	17	-450	-2747.1%
Anticipated Resources	26,342	26,202	-0.5%
Existing-Other Capacity	0	0	n/a
Prospective Resources	26,342	26,202	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.2%	25.1%	-3.1
Prospective Reserve Margin	28.2%	25.1%	-3.1
Reference Margin Level	12.0%	11.5%	-0.5

NPCC-New York			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,220	23,800	-1.7%
Demand Response: Available	803	802	-0.1%
Net Internal Demand	23,417	22,998	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	39,697	40,522	2.1%
Tier 1 Planned Capacity	0	0	n/a
Net Firm Capacity Transfers	1,589	759	-52.2%
Anticipated Resources	41,285	41,281	0.0%
Existing-Other Capacity	0	0	n/a
Prospective Resources	41,285	41,281	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	76.3%	79.5%	3.2
Prospective Reserve Margin	76.3%	79.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,642	40,512	-0.3%
Demand Response: Available	2,914	4,451	52.8%
Net Internal Demand	37,728	36,061	-4.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	42,423	41,560	-2.0%
Tier 1 Planned Capacity	0	73	n/a
Net Firm Capacity Transfers	-726	-479	-34.0%
Anticipated Resources	41,697	41,154	-1.3%
Existing-Other Capacity	0	0	n/a
Prospective Resources	42,797	41,154	-3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	10.5%	14.1%	3.6
Prospective Reserve Margin	13.4%	14.1%	0.7
Reference Margin Level	10.5%	10.5%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	132,667	136,328	2.8%
Demand Response: Available	5,189	5,616	8.2%
Net Internal Demand	127,478	130,712	2.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,060	179,216	0.1%
Tier 1 Planned Capacity	0	0	n/a
Net Firm Capacity Transfers	-872	4,502	-616.3%
Anticipated Resources	178,188	183,718	3.1%
Existing-Other Capacity	0	0	n/a
Prospective Resources	178,188	183,718	3.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.8%	40.6%	0.8
Prospective Reserve Margin	39.8%	40.6%	0.8
Reference Margin Level	27.0%	30.0%	-9.3

SERC-Central			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,282	42,895	1.4%
Demand Response: Available	1,753	1,497	-14.6%
Net Internal Demand	40,529	41,397	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,196	51,578	2.8%
Tier 1 Planned Capacity	1386	0	-100.0%
Net Firm Capacity Transfers	1,145	1,922	67.9%
Anticipated Resources	52,727	53,500	1.5%
Existing-Other Capacity	1,255	1,498	19.4%
Prospective Resources	54,002	54,998	1.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.1%	29.2%	-0.9
Prospective Reserve Margin	33.2%	32.9%	-0.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,044	45,005	-0.1%
Demand Response: Available	912	982	7.7%
Net Internal Demand	44,132	44,023	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,229	54,379	0.3%
Tier 1 Planned Capacity	55	72	31.8%
Net Firm Capacity Transfers	624	593	-5.0%
Anticipated Resources	54,908	55,045	0.2%
Existing-Other Capacity	3	5,209	-
Prospective Resources	54,910	60,254	9.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.4%	25.0%	0.6
Prospective Reserve Margin	24.4%	36.9%	12.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,470	48,494	0.0%
Demand Response: Available	2,753	2,780	1.0%
Net Internal Demand	45,717	45,714	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,679	62,579	-0.2%
Tier 1 Planned Capacity	344	15	-95.6%
Net Firm Capacity Transfers	509	400	-21.4%
Anticipated Resources	63,531	62,994	-0.8%
Existing-Other Capacity	1,563	3,673	135.1%
Prospective Resources	65,094	66,667	2.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.0%	37.8%	-1.2
Prospective Reserve Margin	42.4%	45.8%	3.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,101	45,308	0.5%
Demand Response: Available	2,018	1,638	-18.8%
Net Internal Demand	43,083	43,670	1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	60,640	62,805	3.6%
Tier 1 Planned Capacity	1165	765	-34.3%
Net Firm Capacity Transfers	-815	-1,192	46.3%
Anticipated Resources	60,990	62,378	2.3%
Existing-Other Capacity	3,090	3,920	26.8%
Prospective Resources	64,081	66,298	3.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.6%	42.8%	1.3
Prospective Reserve Margin	48.7%	51.8%	3.1
Reference Margin Level	15.0%	15.0%	0.0

SPP			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,996	45,788	4.1%
Demand Response: Available	278	1,128	305.9%
Net Internal Demand	43,718	45,926	5.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,173	67,252	9.9%
Tier 1 Planned Capacity	0	0	n/a
Net Firm Capacity Transfers	-498	-1,116	124.4%
Anticipated Resources	60,676	66,136	9.0%
Existing-Other Capacity	0	0	n/a
Prospective Resources	60,630	66,090	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	38.8%	44.0%	5.2
Prospective Reserve Margin	38.7%	43.9%	5.2
Reference Margin Level	19.0%	19.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	70,451	73,193	3.9%
Demand Response: Available	4,868	5,447	11.9%
Net Internal Demand	65,583	67,746	3.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	92,387	98,712	6.8%
Tier 1 Planned Capacity	228	239	4.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	92,635	98,971	6.8%
Existing-Other Capacity	0	0	n/a
Prospective Resources	93,203	99,691	7.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.2%	46.1%	4.8
Prospective Reserve Margin	42.1%	47.2%	5.0
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,961	12,280	2.7%
Demand Response: Available	0	0	n/a
Net Internal Demand	11,961	12,280	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,694	13,535	-1.2%
Tier 1 Planned Capacity	1511	3206	112.2%
Net Firm Capacity Transfers	0	0	n/a
Anticipated Resources	15,205	16,740	10.1%
Existing-Other Capacity	0	0	n/a
Prospective Resources	15,205	16,740	10.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.1%	36.3%	9.2
Prospective Reserve Margin	27.1%	36.3%	9.2
Reference Margin Level	13.7%	9.5%	-4.2

WECC-BC			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,651	11,966	2.7%
Demand Response: Available	0	0	n/a
Net Internal Demand	11,651	11,966	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,166	13,870	5.3%
Tier 1 Planned Capacity	134	433	222.4%
Net Firm Capacity Transfers	110	164	49.1%
Anticipated Resources	13,410	14,467	7.9%
Existing-Other Capacity	0	0	n/a
Prospective Resources	13,410	14,467	7.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.1%	20.9%	5.8
Prospective Reserve Margin	15.1%	20.9%	5.8
Reference Margin Level	13.7%	12.8%	-0.9

WECC-CA/MX			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	38,328	36,095	-5.8%
Demand Response: Available	755	737	-2.4%
Net Internal Demand	37,573	35,359	-5.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	56,405	56,300	-0.2%
Tier 1 Planned Capacity	5400	4671	-13.5%
Net Firm Capacity Transfers	315	0	-100.0%
Anticipated Resources	62,120	60,971	-1.8%
Existing-Other Capacity	0	0	n/a
Prospective Resources	62,136	61,092	-1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	65.3%	72.4%	7.1
Prospective Reserve Margin	65.4%	72.8%	7.4
Reference Margin Level	11.0%	9.3%	-1.7

WECC-NW			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	57,408	58,404	1.7%
Demand Response: Available	578	403	-30.2%
Net Internal Demand	56,829	58,001	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	77,389	82,722	6.9%
Tier 1 Planned Capacity	2188	3756	71.7%
Net Firm Capacity Transfers	1,964	5,098	159.6%
Anticipated Resources	81,541	91,576	12.3%
Existing-Other Capacity	0	0	n/a
Prospective Resources	81,558	91,936	12.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	43.5%	57.9%	14.4
Prospective Reserve Margin	43.5%	58.5%	15.0
Reference Margin Level	17.4%	19.0%	1.6

WECC-SW			
Demand, Resource, and Reserve Margins	**2023–2024 WRA**	**2024–2025 WRA**	**2023–2024 vs. 2024–2025**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	15,743	16,517	4.9%
Demand Response: Available	285	340	19.4%
Net Internal Demand	15,458	16,177	4.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	28,306	29,380	3.8%
Tier 1 Planned Capacity	1129	1997	76.9%
Net Firm Capacity Transfers	0	0	n/a
Anticipated Resources	29,435	31,377	6.6%
Existing-Other Capacity	0	0	n/a
Prospective Resources	29,587	31,778	6.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	90.4%	94.0%	3.5
Prospective Reserve Margin	91.4%	94.0%	2.6
Reference Margin Level	16.4%	15.5%	-0.9

Variable Energy Resource Contributions

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			Hydro		
Assessment Area/Interconnection	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	41,349	16,761	41%	11,423	536	5%	6,846	4,076	60%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	202	40	20%
MRO-SaskPower	815	164	20%	22	0	0%	848	674	79%
NPCC-Maritimes	1,823	261	14%	191	5	3%	906	902	96%
NPCC-New England	2,548	939	37%	2,970	9	0%	3,874	3,335	86%
NPCC-New York	2,590	728	28%	860	0	0%	990	684	82%
NPCC-Ontario	4,943	1,364	28%	478	0	0%	8,862	5,531	62%
NPCC-Québec	4,024	1,449	36%	10	0	0%	446	446	100%
PJM	11,701	3,620	31%	10,735	1	0%	8,136	7,349	90%
SERC-Central	982	176	18%	1,203	455	38%	4,966	4,035	81%
SERC-East	0	0	0%	6,966	2,526	36%	3,072	3,023	98%
SERC-Florida Peninsula	0	0	0%	9,975	1,684	17%	0	0	0%
SERC-Southeast	0	0	0%	5,996	3,861	64%	3,250	3,258	100%
SPP	34,689	4,951	14%	703	36	5%	114	71	62%
Texas RE-ERCOT	39,533	15,697	40%	29,129	15	0%	557	388	70%
WECC-AB	5,559	1,867	34%	3,042	0	0%	894	285	32%
WECC-BC	776	279	36%	2	0	0%	16,902	12,623	75%
WECC-CA/MX	7,694	569	7%	24,905	0	0%	13,725	3,599	26%
WECC-SW	3,784	1,065	28%	5,944	182	3%	1,201	242	20%
WECC-NW	23,518	7,876	33%	12,787	2,198	17%	42,102	23,073	55%
EASTERN INTERCONNECTION	100,483	28,991	29%	69,052	9,114	13%	42,066	32,978	78%
QUÉBEC INTERCONNECTION	4,024	1,449	36%	10	0	0%	446	446	100%
TEXAS INTERCONNECTION	39,533	15,697	40%	29,129	15	0%	557	388	70%
WECC INTERCONNECTION	41,332	11,657	28%	46,680	2,380	5%	73,930	39,537	53%
INTERCONNECTION TOTAL:	**185,273**	**57,794**	**31%**	**144,567**	**11,509**	**8%**	**117,481**	**73,021**	**62%**

Errata

December 2024

- Edited Risk Key legend for Figure 1: Winter Reliability Risk Area Summary (p. 5)
- Changed color coding for MISO waterfall chart “Fuel Supply Issues” to reflect that it is an extreme derate (p. 15)
- Corrections made to the VER Table (page 45): Texas RE-ERCOT Wind Nameplate Capacity, Eastern Interconnection Total, and Texas Interconnection Total
- Resized waterfall charts for MRO-SaskPower (p. 17), SERC-E (p. 25), SERC-SE (p. 27), and WECC-CA/MX (p. 32)