2021–2022 Winter Reliability Assessment

November 2021

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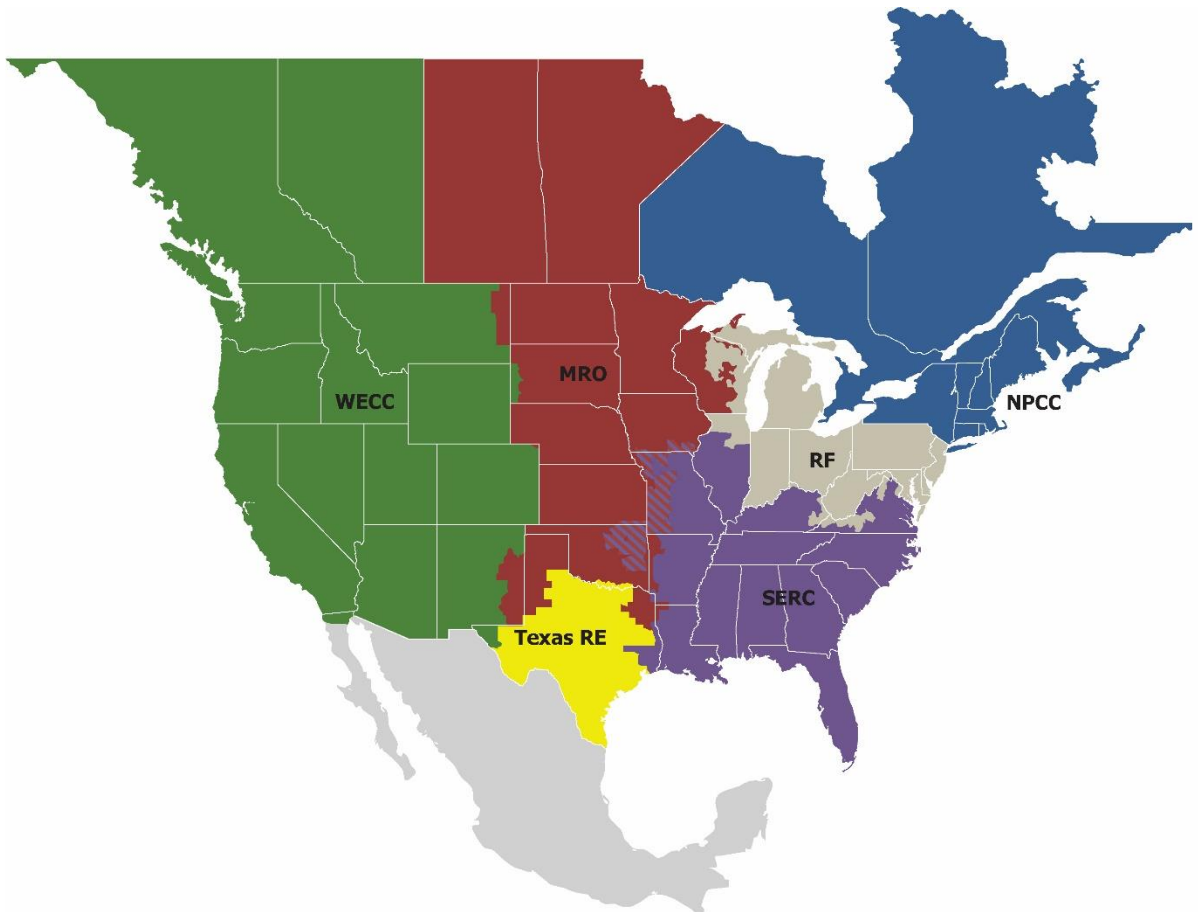
Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (RE), is a highly reliable 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

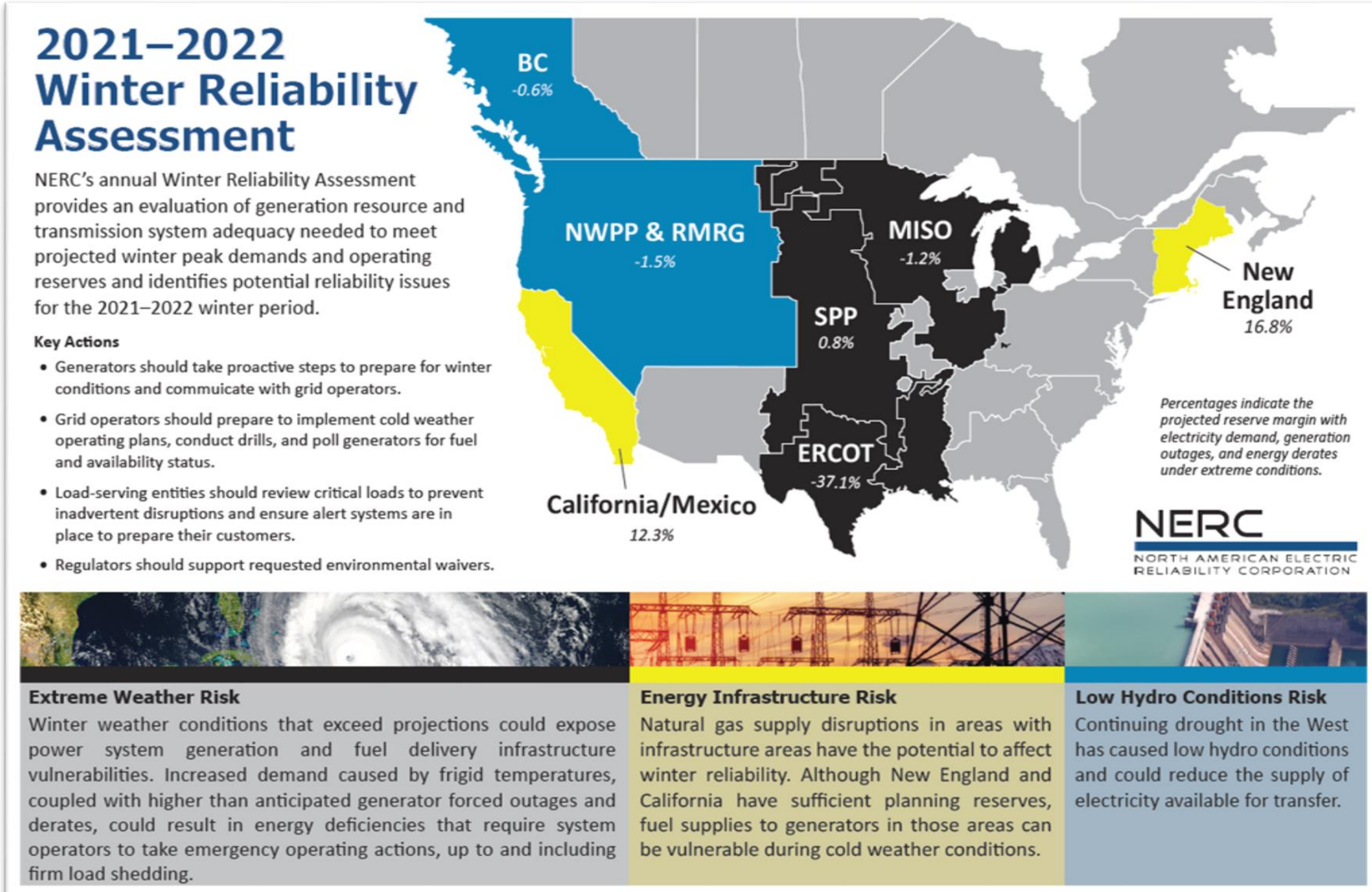
The North American BPS is made up of six RE boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessments Dashboards** section.



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 *2021-2022 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 impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the REs, and NERC staff using demand and resource projections obtained from the assessment areas. This report reflects NERC's independent assessment 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. The below infographic provides a basic overview.



Key Findings

NERC's annual WRA covers the upcoming three-month (December–February) 2021–2022 winter period. This assessment provides an evaluation of 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 topics of concern. The following findings represent NERC's independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the upcoming winter:

- **Extreme weather events, including extended durations of colder than normal weather, pose a risk to the uninterrupted delivery of power to electricity consumers:** Winter weather that exceeds projected conditions can expose power system generation and fuel delivery infrastructure vulnerabilities and challenge electricity system operators' ability to maintain reliability of the BPS. Although Anticipated Reserve Margins meet or surpass the Reference Margin Level in all areas as shown in the **Resource Adequacy** section, harsh conditions characterized by extreme or prolonged cold temperatures over a large area create unique challenges in maintaining grid reliability in many parts of the North American BPS. Such conditions occurred most recently in North America during the February 2021 North American cold weather event.[1] Increased demand caused by frigid temperatures and higher than anticipated generator forced outages and derates in susceptible areas could create conditions that lead system operators to take emergency operating actions, up to and including firm load shedding, as a result of energy emergencies. NERC's operational risk assessment, which is presented in detail in the **Risk Highlights for Winter 2021–2022** section, identifies BPS resource deficiencies in parts of North America (**Figure 1**) that could occur during extreme winter weather. Peak demand or generator outages that exceed forecasts—at levels that have been experienced in previous winter events—can be expected to cause energy emergencies in MISO, SPP, and Texas RE-ERCOT.

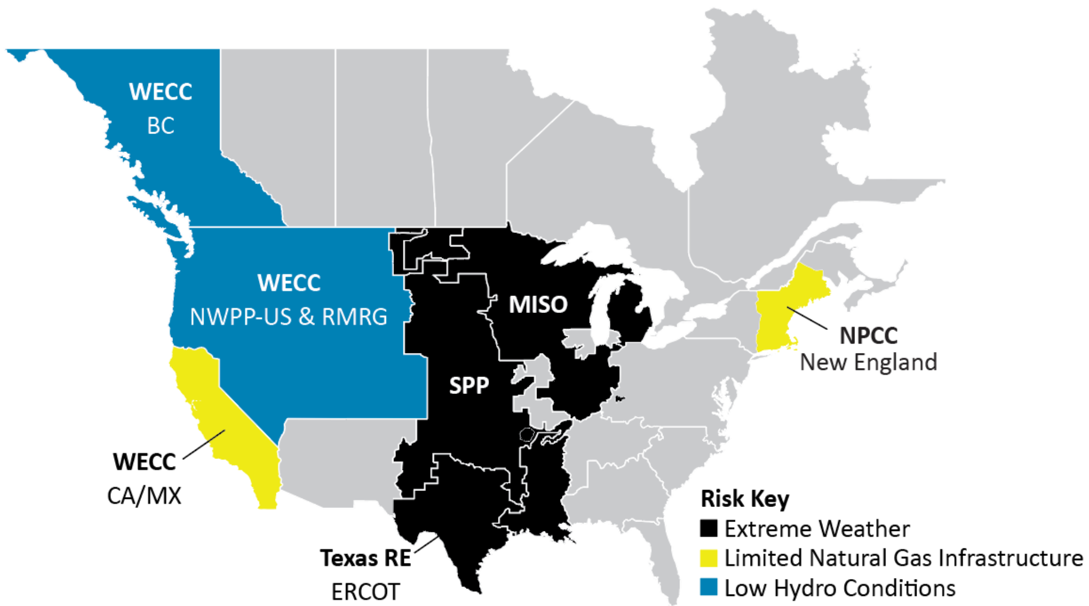


Figure 1: Winter Reliability Risk Area Summary

- **Natural gas supply disruptions in infrastructure-limited areas have the potential to affect winter reliability:** Disruptions to pipeline natural gas supplies and natural gas production sites, as observed in Texas RE-ERCOT in February 2021, can have the potential to affect power system reliability in winter. Although New England and the U.S. Southwest have sufficient planning reserves, fuel supplies to generators in those areas can be vulnerable during cold weather conditions. In NPCC-New England, the capacity of natural gas transportation infrastructure can be constrained when cold temperatures cause peak demand for both electricity generation and consumer space heating needs. Potential constraints on the fuel delivery systems and limited inventory of liquid fuels may exacerbate the risks for fuel based generator outages and reductions. Southern California and the U.S. Southwest have limited natural gas storage and lack redundancy in supply infrastructure. As a result, electricity generators face the risk of fuel supply curtailment or disruption from extreme winter weather events.[2, 3] A ruptured interstate natural gas pipeline in August has caused an outage that reduces the amount of natural gas flowing into California. Natural gas storage levels in the

[1] See the FERC and NERC staff Inquiry preliminary findings and recommendations: February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations - PPT Version | Federal Energy Regulatory Commission (ferc.gov)

[2] ISO-NE Winter 2017/2018 Recap: Historic cold snap reinforces findings in Operational Fuel-Security Analysis: https://isonewswire.com/2018/04/25/winter-2017-2018-recap-historic-cold-snap-reinforces-findings-in-operational-fuel-security-analysis/

[3] Western Interconnection Gas–Electric Interface Study: https://www.wecc.org/Reliability/Western%20Interconnection%20Gas%20Electric%20Interface%20Study%20Public%20Report.pdf

area will decline during periods of high demand while the outage persists. Electricity reliability would not be affected in average temperatures and conditions, however prolonged periods of cold temperatures could result in curtailment of natural gas fuel to generators.[4]

- **Continuing drought in the west can cause low hydro conditions for the upcoming winter and reduce the supply of electricity for transfer throughout the area:** Although resources are expected to be sufficient for peak demand, higher demand from more extreme temperatures in the northwest could cause a shortfall. Low hydro conditions can reduce transfers needed to mitigate a wide area cold weather event.
- **Generator Owners are facing challenges in obtaining fuels as many supply chains are stressed:** No specific BPS reliability impacts are currently foreseen; however, owners and operators of fossil-fired generators will need to monitor their coal and fuel oil stores and natural gas contracts as late-stage acquisitions are less assured this winter. Regional natural gas storage levels are below average as a result of natural gas infrastructure maintenance and high natural gas usage throughout the warm summer months. In most assessment areas, natural gas reliance as a generator fuel has increased in recent years. NPCC-New England competes for liquefied natural gas supply on the world market—some of which powers electric generation in the area—and unprecedented high liquefied natural gas demand is anticipated for the upcoming 2021–2022 winter months. These potential constraints could challenge many owners of fossil-fired plants over the winter and underscore the need for operators at the Balancing Authorities (BAs) and Reliability Coordinators (RCs) to include generator fuel surveying in their operating plans.
- **Responses to NERC's Level 2 Alert—*Cold Weather Preparations for Extreme Weather Events*—indicate that operating plans for winter are in place, but generator resource availability could again suffer as a result of equipment failure or lack of fuel under severe winter conditions:** In August, the ERO issued a Level 2 NERC Alert to RCs, BAs, Transmission Operators (TOPs), and Generator Owners (GOs). The alert includes five recommendations as well as a series of questions to help evaluate the Bulk Electric System's winter readiness. Responses indicate that grid operators have put operating plans in place to reduce seasonal risks and maintain system reliability. However, GOs and grid operator's responses to questions about winterization plans and fuel coordination indicate that some plant vulnerabilities can be anticipated for the upcoming winter. The responses indicate the importance for grid operators to be prepared to implement their operating plans to manage potential supply shortfalls in extreme weather.

[4] See California Public Utilities Commission *Winter 2021-22 Southern California Reliability Assessment*: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/winter2021-22-reliabilityassessment.pdf

Recommendations

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

Grid operators, GOs, and Generator Operators (GOPs) should review NERC Level 2 alert—*Cold Weather Preparations for Extreme Weather Events*—and take recommended steps prior to winter.

Grid operators should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, and sustained operations in extreme conditions. BAs should poll their generating units periodically and in advance of approaching severe weather to understand their readiness level for normal and extreme conditions, giving consideration for unit weatherization as well as fuel supply risk.

BA and RC should conduct drills on alert protocols to ensure that they are prepared to signal need for conservative operations, restrictive maintenance periods, etc. BA and GOPs should verify protocols and operator training for communication and dispatch.

Distribution providers and load-serving entities should review non-firm customer inventories and rolling black out procedures to ensure that no critical infrastructure loads (e.g., natural gas, telecommunications) would be affected. Rehearse protocols that prepare customers for impacts of severe weather.

February 2021 Cold Weather Event: Winter Storm Uri

From February 13–17, 2021, the Central United States suffered an intense and prolonged cold wave that affected many areas across the Texas RE-ERCOT, MISO, and SPP assessment areas. Increasing demand was unable to be met as generation and transmission experienced widespread outages. FERC, NERC and the REs launched the *February 2021 Cold Weather Grid Operations* joint inquiry regarding the BPS events as a result of winter storm Uri. The inquiry identified the following root causes:

- Generation freezing
- Limited natural gas fuel supply
- Natural gas and electricity interdependency
- ERCOT firm load shed affected natural gas facilities
- Manual and automatic load shed coordination

Generators without winterization experienced mechanical failures from a variety of causes that include frozen instrumentation and loss of ancillary support systems, such as airflow, cooling, and internal fuel delivery. Wind generators' failures were attributable to iced wind turbine blades. Freezing and power outage issues at both gathering and processing facilities for natural gas caused limited natural gas supply for generators. Firm load shed affected power supply to various natural gas production and processing facilities that in turn led to further forced outages for natural gas generators. ERCOT ordered firm load shed for nearly three consecutive days that reached a peak of 20,000 MW ordered off-line at its worst point. During this time, ERCOT experienced a peak of 34,000 MW of generation outages for over two consecutive days. SPP ordered approximately five hours of firm load shed reaching 2,700 MW at its peak, and MISO experienced over two hours of firm load shed with 700 MW ordered off-line at its worst point. The ERO has taken the following actions to address concerns for extreme weather risks for future winters:

- Conducted the joint FERC-NERC Inquiry
- Issued NERC Level 2 alert: *Cold Weather Preparations for Extreme Weather Events*
- Developed cold weather Reliability Standards that have been adopted by the NERC Board of Trustees and filed with applicable regulatory authorities. In the United States, the new cold weather requirements will become effective in 2023.
- Prepared this 2021–2022 *Winter Reliability Assessment*

Recommendations from the inquiry include Reliability Standards, generator winterization, natural gas infrastructure winterization, and establishing a natural gas-electric reliability forum. An in-depth evaluation of the February 2021 cold weather event on BPS operations is included in the joint FERC-NERC inquiry.[5]

[5] FERC, NERC Staff Review 2021 Winter Freeze, Recommend Standards Improvements

Risk Highlights for Winter 2021–2022

Winter weather conditions that exceed projected conditions and expose power system generation and fuel delivery infrastructure vulnerabilities can challenge electricity system operators' ability to maintain reliability of the BPS. Specific risks for the upcoming winter are analyzed in this section of the *WRA*.

Seasonal Risk Assessments of Area Resource and Demand Scenarios

Areas can face energy shortfalls despite having Planning Reserve Margins that exceed Reference Margin Levels. Operating resources may be insufficient during periods of peak demand for reasons that could include generator scheduled maintenance, forced outages due to normal and more extreme weather conditions and loads, or low-likelihood conditions that affect generation resource performance or unit availability, including constrained fuel supplies. The **Regional Assessment Dashboards** section in this report includes a seasonal risk scenario for each area that illustrates variables in resources and load and the potential effects that operating actions can have to mitigate shortfalls in operating reserves. **Figure 2** shows an example seasonal risk assessment for the Independent System Operator-New England (ISO-NE) area that was developed with data from NPCC and ISO-NE. 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 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. A description of resource and demand variables for **Figure 2** is found in **Table 1**.

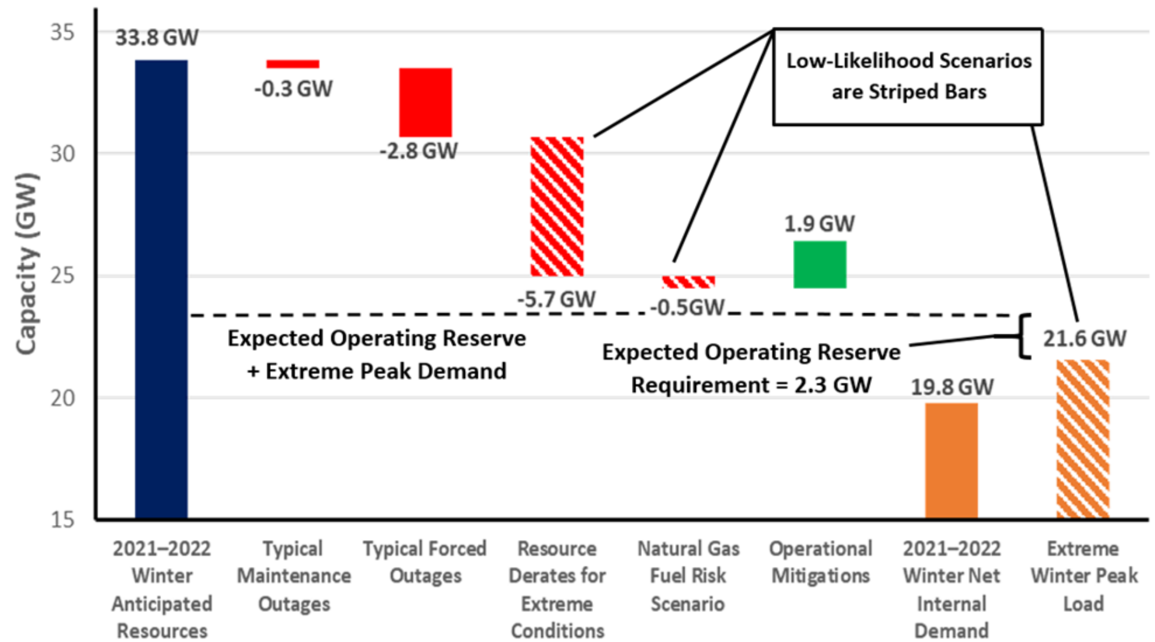


Figure 2: ISO-NE Area Seasonal Risk Assessment at Extreme Peak Demand

The seasonal risk assessment for ISO-NE shows that resources are available to meet extreme conditions. Based on the assumptions in **Table 1**, resources are available to meet expected operating reserve requirements for the normal and extreme demand and outage scenarios analyzed. By examining various maintenance and forced outage scenarios and seasonal derated resource conditions, the seasonal risk assessment analysis provides insights into operational challenges that can occur as a result of prolonged and extreme cold temperatures.

Table 1: Resource and Demand Variables in the ISO-NE Seasonal Risk Assessment		
Resource Scenarios		
Typical Maintenance Planned Outages	Typical maintenance outages refer to all planned outages for the period, including any known long-term outages, generation outages, reductions due to transmission work, and external outages that would affect ISO-NE imports. The value is a snapshot of these considerations that is produced monthly and forecast out two years.	-0.3 GW
Typical Forced Outages	Typical forced outages refer to an estimate of generation resources that will experience forced outage during peak load conditions. ISO-NE calculated this capacity value from historical forced outages in previous winters.	-2.8 GW
Resource Derates for Extreme Conditions (Low-likelihood)	A low-likelihood, high forced outage scenario is used to analyze the effect of cold weather-driven generation outages. The assumed forced outage for this scenario is based on the sum of the unplanned outages beyond typical forced outages that are expected to be caused by extreme cold weather physically impacting generator availability (e.g., frozen sensing lines or equipment failure).	-5.7 GW
Extreme Natural Gas Fuel Risk Scenario (Low-likelihood)	ISO-NE depends on a large fleet of natural-gas-fired generation that may be at risk due to high firm demand, resulting in the unavailability of natural gas during colder temperatures. ISO-NE calculates the amount of generator natural gas at risk due to lack of natural gas during cold weather based on dry-bulb average temperature. This assumes no generator natural gas at risk for temperatures at or above 30°F and a reduction curve for temperatures below 30°F. The electric generating capacity depicted as at-risk in Figure 2 is the maximum.	-0.5 GW
Operational Mitigations	An estimated combination of load relief is achieved through operating procedure actions (e.g., requesting voluntary load curtailment of market participants, the purchase of available emergency capacity and energy from market participants or neighboring RC or BA areas, request for generators and demand response resources not subject to market obligations to voluntarily provide energy for reliability, requesting voluntary load curtailment by large industrial and commercial customers, and radio and television appeals for voluntary load curtailment).	+1.9 GW
Demand Scenarios		
2021–2022 Winter Net Internal Demand	This is the forecast 50/50 net winter peak load that integrates state historical demand, economic and weather data, and the impacts of utility-sponsored conservation and peak-load management programs. Energy efficiency is included in this demand forecast and assumes that behind-the-meter solar generation will be off-line or unable to generate for the peak winter hours.	
Extreme Winter Peak Load	Demand Scenarios beyond (90/10) are tested to determine the level of risk and actions required to maintain the integrity of the interconnected BPS, which includes emergency actions up to and including load shedding.	

The seasonal risk assessment does not account for all of the unique energy assurance risks associated with the area. Long-duration cold spells and disruptions to primary and back-up fuel supply chains are not explicitly considered in the New England seasonal risk scenario and can cause unique risks to the area's operations. Conditions such as these occurred in the 2017–2018 winter and led to a rapid decline in fuel oil inventories used by electricity generators. Gripped by a cold weather stretch for an extended duration between December 25 and January 8, all major cities in New England had average temperatures below normal for at least 13 consecutive days, of which 10 days averaged more than 10°F below normal. Overall, there was significantly higher than normal use of oil, and coal use also increased over its normal use. Natural gas and oil fuel price inversion led to oil being in economic merit and base loaded. As natural gas became uneconomic, the entire season's oil supply rapidly depleted. The amount of electricity generated from natural gas declined significantly at the end of December as temperatures plunged, and most available pipeline capacity was used to serve firm local natural gas distribution company demand for heating customers. Oil-fired generation increased sharply during the same period, surpassing natural-gas-fired generation on December 28. With extended days of burning oil, several resources either had concerns about hitting federal and/or state emissions limitations or were impacted by emissions limitations. This primarily includes resources in Massachusetts, Connecticut, and Rhode Island. As oil inventories depleted, replenishment could not keep up with demand until January 9 when cold temperatures eased. Figure 3 shows the impact the cold weather had on fuel oil inventories during the event.[6]

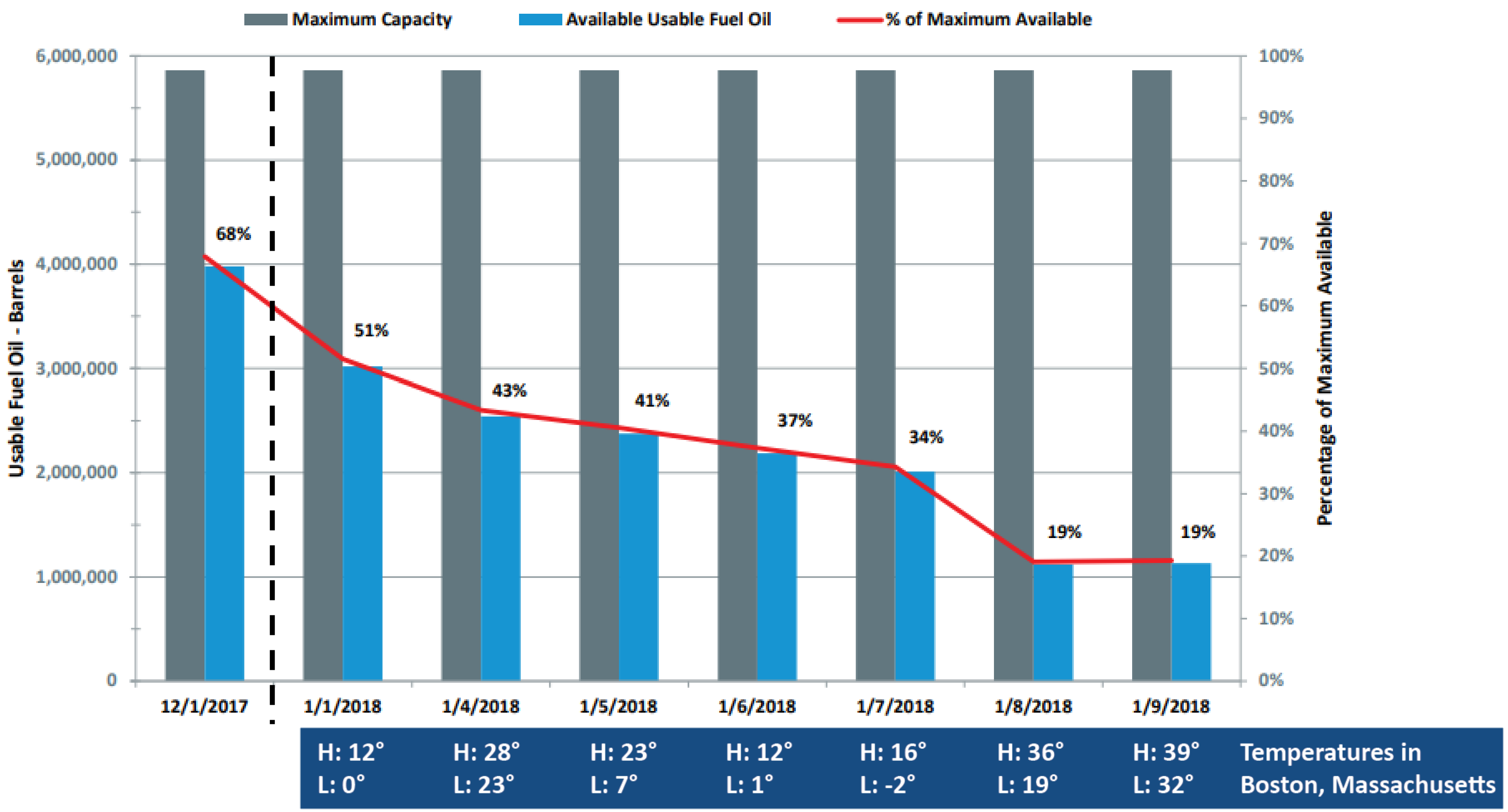


Figure 3: Fuel Oil Inventories in ISO-NE during 2017–2018 Winter[5]

This chart is an approximation of usable oil, discounting unit outages, reductions, or emissions.

[6] https://www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf

Since the winter of 2017–2018, ISO-NE has implemented the 21-Day Energy Forecast and Report[7] that is published to provide market participants with early indications of potential fuel scarcity conditions and help inform fuel procurement decisions. ISO-NE surveys fossil-fueled generators on a weekly basis in winter to monitor and confirm their current and expected fuel availability. If conditions require more frequent updates, these surveys may be sent daily. ISO-NE also requests that all natural-gas-fired generators confirm adequate natural gas supply and transportation nominations to meet their day-ahead obligations during these energy assessments.

Actual Generation Outages and Derates

Seasonal risk assessments are informed by historical data on generation outages and derates. NERC's Generating Availability Data System (GADS) is one source of information that is used to obtain historical information of the impact to conventional thermal and hydro generation during winter periods.[8] **Table 2** and **Table 3** show the peak generation outage and derated capacity and proportion to overall fuel-type nameplate capacity reported to GADS for affected assessment areas during periods of extreme winter weather that occurred in January 2018 and February 2021. Wind and solar generation also experience outages and derates; however, this data is not collected in the GADS conventional database used for the tables. Wind and solar generation is derated in the *WRA* to account for ambient light and expected weather conditions around the time of peak demand (i.e., peak daily demand in winter occurs in early morning hours or other times of darkness for most areas).

Table 2: February 2021 Peak Generation Outage and Derate [9]

	Coal fired		Nuclear		Natural Gas Fired	
Area	**MW**	**Percent**	**MW**	**Percent**	**MW**	**Percent**
MISO	7,202	13%	2,129	10%	9,323	16%
SERC-Central	564	3%	-	-	1,185	9%
SERC-Southeast	914	5%	-	-	3,383	9%
SPP	6,219	17%	-	-	13,589	42%
Texas RE-ERCOT	3,680	27%	1,181	23%	22,566	38%
WECC-NWPP-US & RMRG	1,968	10%	-	-	1,285	6%

Table 3: January 2018 Peak Generation Outage and Derate[10]

	Coal fired		Nuclear		Natural Gas Fired	
Area	**MW**	**Percent**	**MW**	**Percent**	**MW**	**Percent**
MISO	7,327	14%	1,570	8%	7,547	13%
NPCC-New York	177	11%	-	-	6,130	37%
PJM	12,186	23%	-	-	2,500	5%
SERC-East	507	3%	932	8%	292	2%
SERC-Florida Peninsula	695	8%	-	-	356	1%
SERC-South East	4,137	21%	-	-	4,610	12%
SPP	1,434	4%	-	-	10,664	33%
Texas RE-ERCOT	1,092	8%	-	-	10,696	18%

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[7] ISO-NE's 21-Day Energy Forecast and Report: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results
[8] See NERC Generating Availability Data System: https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx
[9] These are the maximum derates and outages reported in GADS in the affected areas during the Texas and Southcentral United States cold weather event that took place February 8–20, 2021.
[10] These are the maximum derates and outages reported in GADS in the affected areas during the January 2018 Southcentral Cold Event from January 15–19, 2018. Details can be found in the event report: https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

Seasonal Risk Assessments for Other Areas

Extreme generation outages and peak loads similar to those experienced in February 2021 are reliability risks in MISO, SPP, and Texas RE-ERCOT areas for the upcoming winter. Seasonal risk scenarios detailing these areas are shown in **Figure 4**. Under studied conditions for these areas, grid operators would need to employ operating mitigations or energy emergency alerts (EEAs) to obtain resources necessary to meet extreme peak demands. **Table 4** describes the various EEA levels and the circumstances for each.

Table 4: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
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 contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	The energy deficient BA is unable to meet minimum contingency reserve requirements.

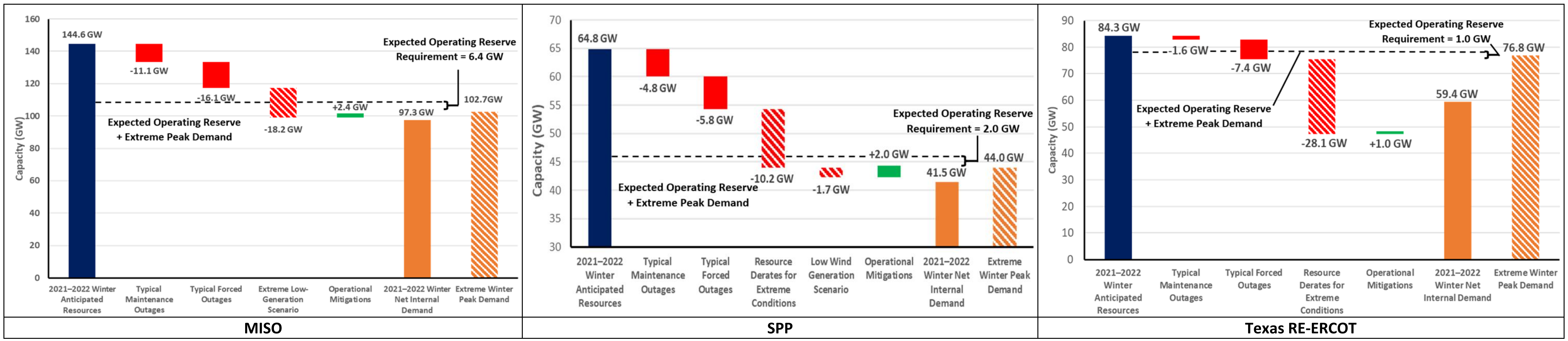


Figure 4: MISO, SPP, Texas RE-ERCOT Seasonal Risk Scenarios

Note: 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 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.

MISO

Expected resources meet operating reserve requirements under the normal peak-demand scenario. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption). EEAs may be needed under extreme peak demand and outage scenarios studied. In MISO's seasonal risk scenario, typical maintenance outages and forced outages are derived from the averages over the past five years. The resource derates in extreme conditions are the maximum outages that occurred in the last five years. The two demands shown for MISO in **Figure 4** are the net internal demand (50/50) and the extreme winter peak demand (90/10) that are derived from demand forecasts with 30 years of historical data. More information about the seasonal risk scenario data description can be found in **Table 1**.

SPP

Expected resources meet operating reserve requirements under the normal peak-demand scenario. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption). EEAs may be needed under extreme peak demand and outage scenarios studied. During winter storm Uri, operators received 3.9 GW of imports to help reduce the amount of firm load shed required to balance supply and demand.

Texas RE-ERCOT

Expected resources meet operating reserve requirements under the normal peak-demand scenario. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption). EEAs may be needed under the extreme peak demand and outage scenarios studied. In the seasonal risk scenario, typical maintenance outages and forced outages are based on historical averages for December through February from the previous three winter seasons, except for February 15–28, 2021. The resource derates for extreme conditions red bar in **Figure 4** includes actual outage rates from winter storm Uri. The two demands shown for Texas RE-ERCOT in **Figure 4** are the net internal demand (50/50) and the extreme winter peak demand (winter storm Uri projected peak). More information about the seasonal risk scenario data description can be found in **Table 1**.

Other Areas

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margins and seasonal risk scenario chart 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 below the seasonal risk scenario charts; see the **Data Concepts and Assumptions** for more information about this chart.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 5**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. The typical outages reserve margin is comprised of anticipated resources, less the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the anticipated reserve margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Table 5: Seasonal Risk Scenario Anticipated Reserve Margins			
Assessment Area	**Anticipated Reserve Margin**	**Anticipated Reserve Margin with Typical Outages**	**Anticipated Reserve Margin with Demand, Outages, and Derates for Extreme Conditions**
MISO	48.5%	20.5%	-1.2%
MRO-Manitoba	17.2%	14.2%	4.2%
MRO-SaskPower	19.3%	16.1%	11.6%
NPCC-Maritimes	26.5%	19.9%	-2.1%
NPCC-New England	71.1%	55.3%	16.8%
NPCC-New York	78.6%	58.4%	33.5%
NPCC-Ontario	20.0%	20.0%	21.3%
NPCC-Québec	12.4%	9.8%	0.6%
PJM	42.0%	29.1%	11.3%
SERC-Central	32.5%	24.4%	9.3%
SERC-East	25.9%	20.6%	4.3%
SERC-Florida Peninsula	35.4%	29.7%	23.2%
SERC-Southeast	38.7%	31.6%	21.1%
SPP	56.4%	30.9%	0.8%
Texas RE-ERCOT	41.9%	26.8%	-37.1%
WECC-NWPP-AB	34.7%	28.6%	8.3%
WECC-NWPP-BC	17.9%	17.8%	-0.6%
WECC-CA/MX	40.3%	33.3%	12.3%
WECC-NWPP-US & RMRG	27.1%	26.6%	-1.5%
WECC-SRSG	103.3%	93.3%	56.5%

NERC Level 2 Alert: Cold Weather Preparations for Extreme Weather Events

Pursuant to Section 810 of its Rules of Procedure,[11] NERC issued the Level 2 industry recommendation—*Cold Weather Preparations for Extreme Weather Events*—on August 18, 2021. NERC Level 2 industry recommendations, also known as Level 2 alerts, provide specific recommended actions that registered entities should consider in response to a particular issue. They are not, however, the same as a Reliability Standard, which contains mandatory obligations and carry penalties for failure to adhere to requirements. The Level 2 alert also contains reporting obligations for entities.

NERC's cold weather Level 2 alert was directed at RC, BA, TOP, and GO functional groups and recommended the following five actions: [12]

- RCs, BAs, and TOPs should create or add to seasonal operating plans for the upcoming winter season at least two months before their winter season with special emphasis on meeting extreme cold weather energy requirements (while also considering resource limitations, such as extreme cold temperatures for a prolonged period of time along with the effects that icing and snow impacts may have on equipment, etc.) Energy aspects of this plan should be informed and updated as per seasonal planning operating plans. RCs, BAs, and TOPs should communicate these plans to GOs within their operating area. Winter seasonal operating plans should include specific considerations listed in the Level 2 alert.

  RCs, BAs, and TOPs should continue, in real-time, especially during periods of extreme cold weather, activities that promote a high-level of situational awareness related to regional energy.

- GOs should review RCs, BAs, and TOPs seasonal operating plans to ensure they contain the current generator availability, fuel supplies, and other related assumptions. Actions should be taken as appropriate based on weather forecasts, resulting capacity, and energy analyses to facilitate readiness while allowing adjustments to be made so there is time for GOs to make the necessary arrangements to maximize the availability of the resources, including, but not limited to, the replenishment of fuel, supplies, labor, and equipment. GOs should maintain communications with fuel suppliers and be prepared to manage resources with fuel switching.

  GOs with wind and solar resources should communicate with RCs, BAs, and TOPs regarding units with cold weather packages, such as de-icing capability, to better assess generating unit availability.

- GOs should communicate forecast and actual unit derates to their RCs, BAs, and TOPs during extreme cold weather events and conditions considering the following factors: unavailability due to weather, fuel constraints (natural gas restrictions), derates for alternate fuels, and potential concerns with increased outages or delayed starts based on unit ambient ratings and historical performance. These communications should be part of the seasonal, outage coordination, day-ahead, and real-time energy assessments.

  RCs, BAs, and TOPs should incorporate the generation unit derate information into their generation capacity, energy analyses, and operating plans. Factors to consider include unavailability due to weather, fuel constraints (natural gas restrictions and refueling limitations), derates for alternate fuels, potential concerns with increased outages or delayed starts based on unit ambient ratings (including accounting for the effect of precipitation and accelerated cooling effect of wind, etc.), and historical performance.

- For manual and automatic load shedding, the following should be completed:
  - RCs, BAs, and TOPs manual and automatic load shedding plans should review critical interdependent subsector electrical loads (as defined by each entity) to avoid being included as part of automatic (i.e., under-frequency) or manual load shedding. This review should be factored into seasonal preparation plans.
  - RCs, BAs, and TOPs should confirm and test manual load shedding processes and capability periodically. These processes and capabilities should be updated with the most recent load forecasts. If these load shedding processes are called upon during real-time operations, they should be monitored during execution as well as recovery.
  - RCs, BAs, and TOPs should track demand response capability and verify that critical interdependent subsector loads are excluded. Operating plans should also take into consideration any limitations on the duration and magnitude of demand response capabilities.

[11] Section 810 of the Rules of Procedure ("Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions") outlines the requirements for industry's response to recommendations.
[12] The alert is available here: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2021-08-18-01%20Extreme%20Cold%20Weather%20Events.pdf

- GOs should conduct dual fuel assessments to ensure resources can switch to the alternate fuel and monitor how much alternate fuel is on site. GOs should also assess generating unit weatherization plans; the implementation of freeze protection measures and factors that could impact availability, including minimum operating temperature; and the application of heat tracing equipment and wind breaks. GOs should inspect and maintain their weatherization measures ahead of the upcoming winter season before the onset of and during extreme cold weather conditions.

In addition to the previous listed five recommendations, the Level 2 alert contained several questions for registered entities. Responses indicate that operating plans for winter are in place, but generator resource availability could again suffer as a result of equipment failure or lack of fuel under severe winter conditions. All RCs responded that their organizations developed operating plans that are closer to real-time (2–3 days ahead) and that these plans address the operating conditions, such as cancellation of outages, generator starting, operating forecasts, and ramping requirements. TOPs also reported a very positive outlook: 80% of TOPs responded that they have or will conduct a seasonal assessment, including weatherization, equipment, and transfer capability. However, BAs and GOs were mixed in their responses with many entities indicating they did not plan to coordinate with fuel providers, conduct fuel surveys, or reinforce weatherization capabilities.

Entities provided an assessment of their generation capacity that will be unavailable due to extreme cold weather conditions. The assessed unavailable capacity of the 197 GOs that indicated they have no plans or partial plans to perform weatherization surveys is 23,850 MW (see **Figure 5** for a regional summary). The MW values displayed in **Figure 5** represent assessed generating capacity without weatherization in each RE that is at risk in extreme weather. Details of the BA and GO responses are located in **Appendix A: NERC Level 2 Alert Questions and Responses**. The responses indicate the importance for grid operators to be prepared to implement their operating plans to manage potential supply shortfalls in extreme weather.

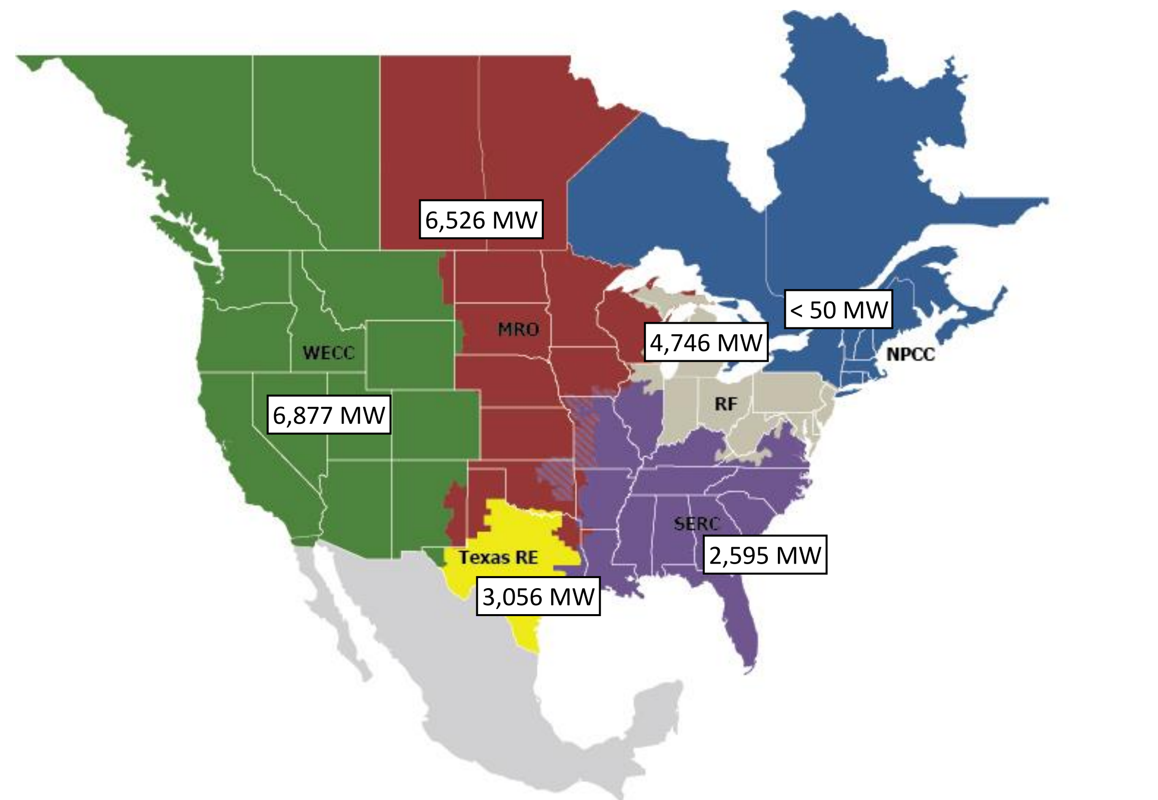


Figure 5: Assessed Unavailable Capacity due to Insufficient Weatherization Plans

Coal Stockpiles

Coal delivery problems by rail can impact the operation of coal-fired electricity generation; likewise, the economics of electricity and energy markets can affect coal supplies. Coal supplies in North America are being affected by the current global energy shortage. Coal stockpiles at individual utilities have trended quickly downward in the last few months as seen in **Figure 6,** after a build-up since last winter.[13] At the end of August, the "average days of burn" (shown as a dotted red line in **Figure 7)** at U.S. power plants was around 85 days based on stockpiles and consumption patterns. This level is not concerning, however a colder than normal winter and high natural gas prices could lead to higher coal consumption and stockpile depletion. Grid operators and assessment areas are monitoring coal resource availability. For example, PJM has initiated the Generation Resource Weekly Fuel Inventory and Supply Data Request that applies to all coal and oil resources. The on-site stockpiles provide fuel and energy assurance that contributes to plant availability and system resilience during extreme weather.

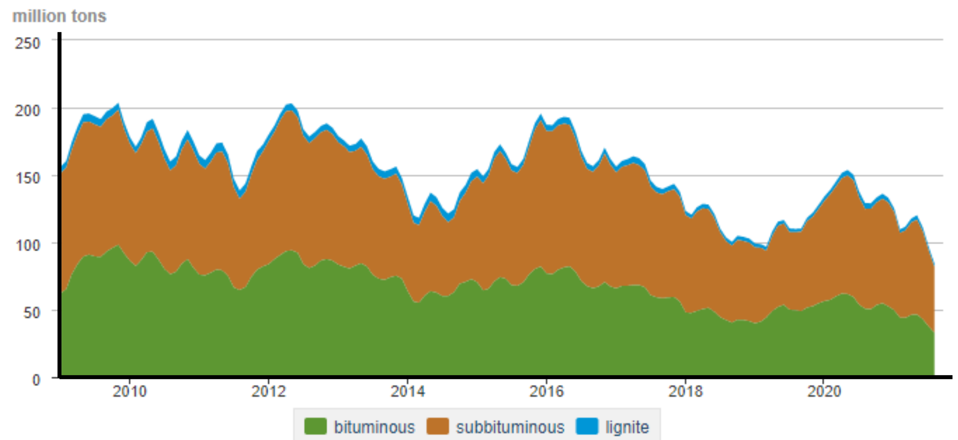


Figure 6: Coal Stocks by Type, January 2009—August 2021

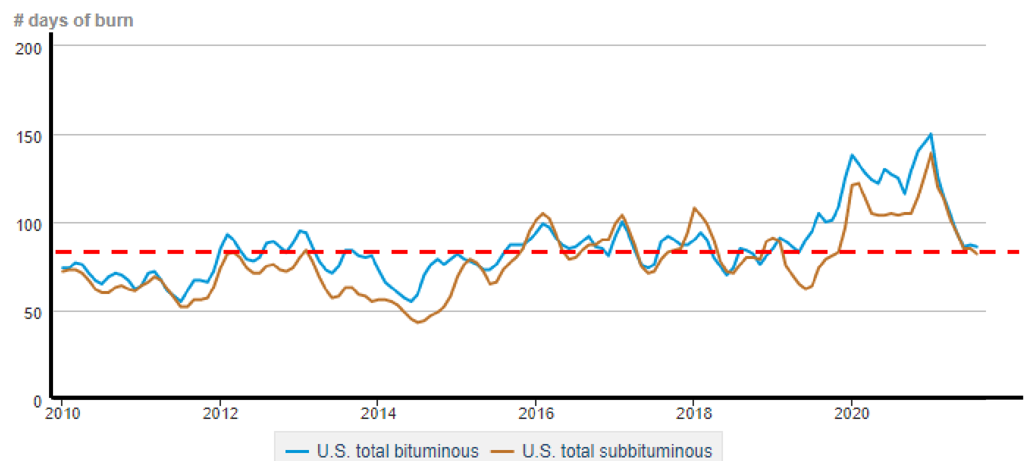


Figure 7: Days of Burn by Non-lignite Coal, January 2010—August 2021

[13] EIA Electric Power Sector Coal Stocks: https://www.eia.gov/electricity/monthly/update/coal-stocks.php

Dual-Fuel Generation

During peak cold temperatures, natural gas supplies may be limited by an increased demand from both electricity generation and consumer space heating needs. However, natural gas generators equipped with dual-fuel capability and supplies of back-up fuel can mitigate the risks associated with limited natural gas supplies during these periods of high demand. **Figure 8** shows the total reported natural gas generating capacity with the portion of dual fuel capability by assessment area. GOs must make preparations for their units to run on back up fuels well in advance. Not only must sufficient fuel be procured, stored, and maintained for use, but generating and auxiliary equipment must be prepared for fuel transition. The capacities shown in **Figure 8** reflect the installed dual fuel capability in each area but may not accurately reflect readiness to operate. Grid operators should also factor in the potential for constrained supply chains to affect fuel and other logistical needs in their operational planning for use of generation with back-up fuels.

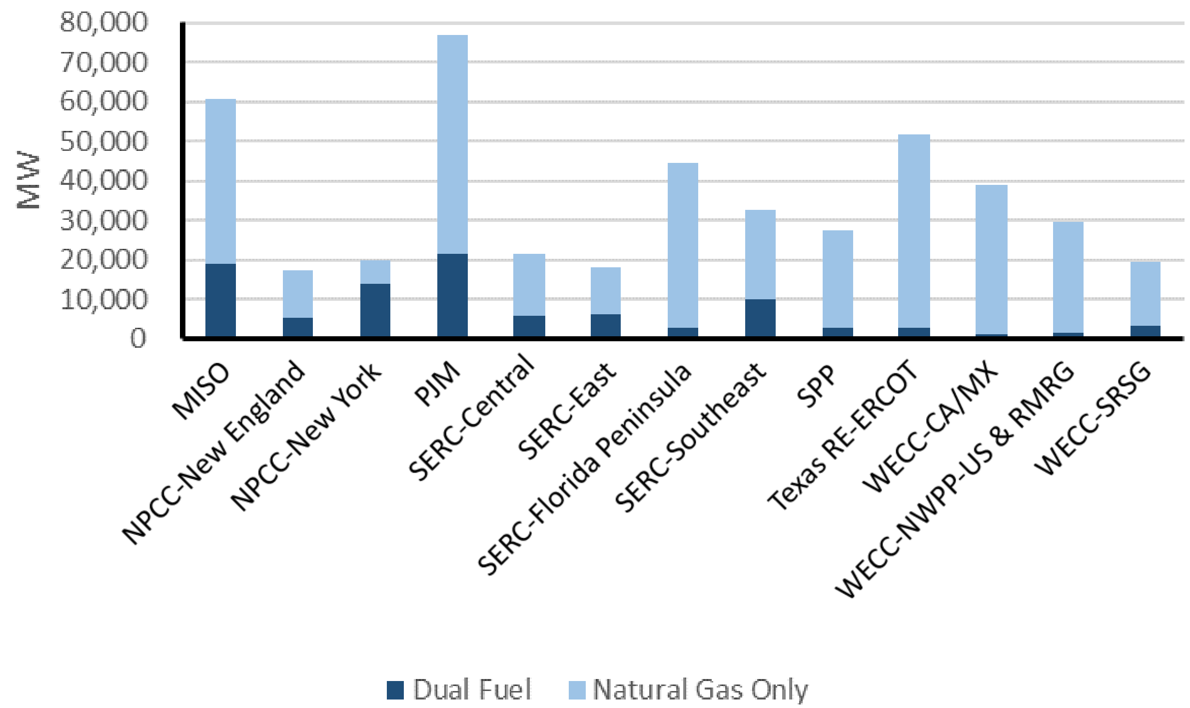


Figure 8: Dual Fuel Generation by Assessment Area

Probabilistic Studies of Winter Reliability Risks

Planners are incorporating sophisticated analysis to identify energy shortfall risks as the generation mix and demand profile becomes increasingly complex. Variable energy resources like wind, solar, and some types of hydro can introduce new periods besides the peak demand hour where there is risk of electricity supplies being insufficient for demand. Likewise, generation outages and fuel limitations alter expected performance of thermal generators. Probabilistic resource adequacy studies can be designed to account for generation and demand characteristics at hourly resolutions and identify the likelihood and severity of energy shortfall. For the upcoming winter, probabilistic studies were performed by planners in several areas.

NPCC Winter Multi-Area Probabilistic Reliability Assessment

A comprehensive probabilistic study of winter resource adequacy is performed annually by planners in the NPCC RE. While final results for the 2021–2022 winter will be published by NPCC in December as part of the NPCC Winter Reliability Assessment, preliminary results indicate there is a low risk of energy shortfall this winter.

Modeling includes a base case of 50/50 peak demand and resource conditions and one or more scenario cases that involve severe demand and low-resource conditions. The NPCC Winter Reliability Assessment also takes into account transfer capabilities with neighboring assessment areas and operating procedures that grid operators use to manage capacity or energy shortfalls. In preliminary results for the 2021–2022 winter season, no unserved energy or load loss hours were identified and all system energy needs were met in the base case and nearly all extreme scenarios (i.e., no expected unserved energy). The scenario with the highest loads and lowest resource availability found energy risk in NPCC-Maritimes, which is also the area with lowest winter Planning Reserve Margins. The final results of NPCC study will be published in December.[14]

Texas RE-ERCOT Probabilistic Risk Assessment

Planners performed a probabilistic resource adequacy assessment for the winter season and determined there is low risk of energy shortfall. However, risk is closely tied to the likelihood of an exceptional winter event, such as winter storm Uri.

The model for this assessment has the following main attributes:

- For a winter peak load day, Monte Carlo simulations determine a forecasted level of operating reserve.
- The hourly range simulated is 7:00 a.m.–9:00 p.m. local time to capture typical morning and evening demand peaks and associated wind and solar ramps.
- For each hour, the model calculates the probability that simulated operating reserves are at or below various risk thresholds for EEA declarations, including firm load shed.
- Based on a given probability of occurrence of an exceptional winter storm event (at least as severe as February's winter storm Uri), the impacts to load, thermal outages/derates, and wind/solar capacity contributions are simulated with probability distributions.

Based on model results for a 0.5% probability of an exceptional winter storm event, the probability of EEA events for the highest-risk hour (8:00 a.m. local time) is approximately 0.7%. This probability varied little across the other hours. Increasing the likelihood of an exceptional winter storm event to 1% caused the risk of EEA events to rise to slightly above 1%.

[14] NPCC seasonal assessment reports are published: https://www.npcc.org/library/reports/seasonal-assessment

MRO-SaskPower Probabilistic Capacity Adequacy Assessment

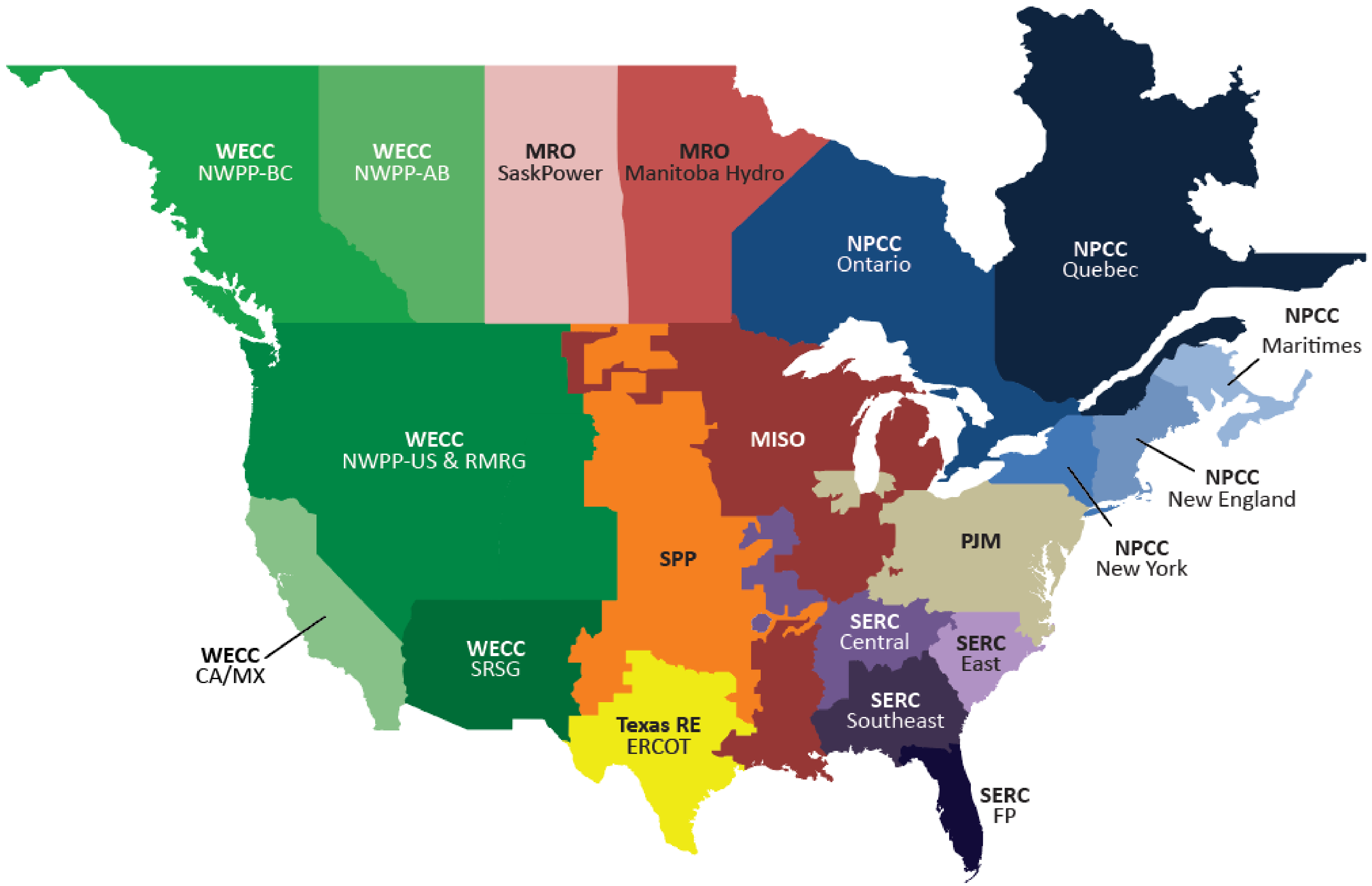
SaskPower performed a probability-based capacity adequacy assessment for the winter of 2021–2022 that includes the following: generation forced outages of 300 MW or greater, extreme peak loads, and available transfer capability from neighboring areas. Based on the capacity adequacy assessment results, they may have to rely on demand response programs (implemented within 12 minutes to 2 hours) and potential load interruptions in November, December, and February months for the winter of 2021–2022 under extreme peak loads. Based on results from generation forced outage models, the probability for exceeding 300 MW of generation forced outages is around 9%.

Additional probabilistic studies can be found in other NERC reliability assessment reports. All assessment areas perform probabilistic studies of future years for NERC's biennial probabilistic assessments. Results of the 2020 Probabilistic Assessment were published in the *2020 LTRA*.[15] Additionally, all areas performed tailored analysis of more extreme conditions. These can be found in the *Probabilistic Assessment Regional Risk Scenarios Report*.[16]

[15] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf
[16] https://www.nerc.com/comm/RSTC/PAWG/2020%20ProbA%20Regional%20Risk%20Scenarios%20Report_final_approved.pdf

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six REs on an assessment area basis. The operational risk analysis shown in the **Regional Assessments Dashboards** provides a deterministic scenario for understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. For each assessment area, 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 WRAreserve 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.



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

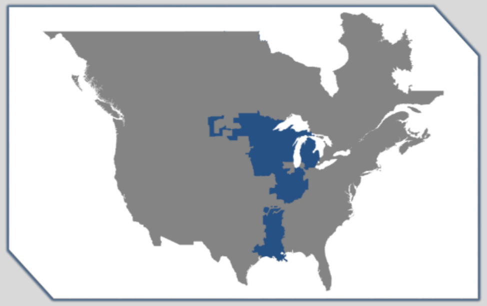
MRO – Midwest Reliability Organization
- MRO-Manitoba Hydro
- MRO-SaskPower
- SPP

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

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

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

WECC
- WECC-CA/MX *(California/Mexico)*
- WECC-NWPP-AB *(Alberta)*
- WECC-NWPP-BC *(British Colombia)*
- WECC-NWPP-US & RMRG *(Northwest Power Pool-United States and the Rocky Mountain Reserve Group)*
- WECC-SRSG *(Southwest Reserve Sharing Group)*

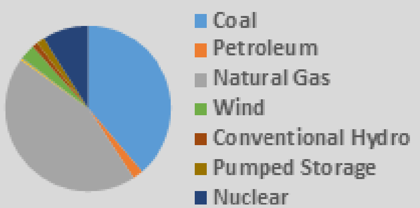


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three REs, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Fuel Mix

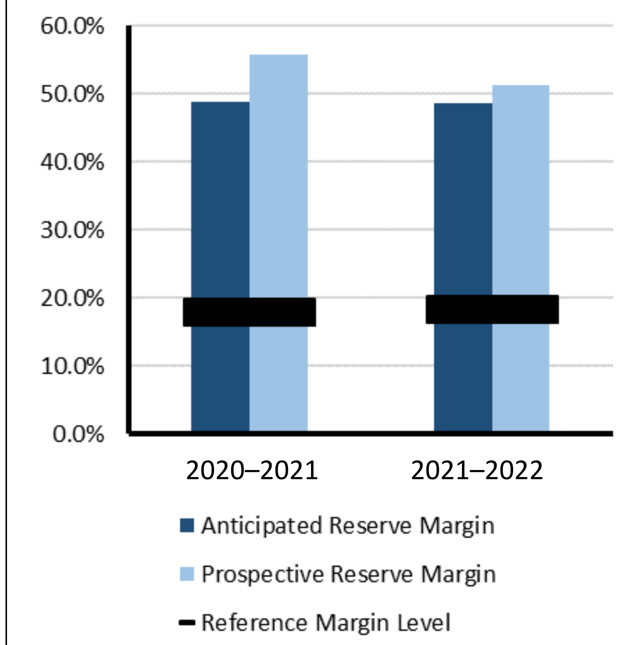


Highlights

MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, MISO is filing changes to the resource adequacy construct to implement a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons, acknowledging that resource adequacy risk is not limited to the summer system peak season.

Though risk has been identified for this upcoming winter season in a high generation outage and high winter load scenario, MISO operators anticipate that system reliability can be maintained by the use of measures that include load modifying resources, energy-only interconnection service resources not included in their capacity resources, internal transfers, and non-firm transfers into the system when necessary and available. MISO continues to coordinate with neighboring RCs and BAs to improve situational awareness and vet any needs for firm or non-firm transfers to address extreme system conditions.

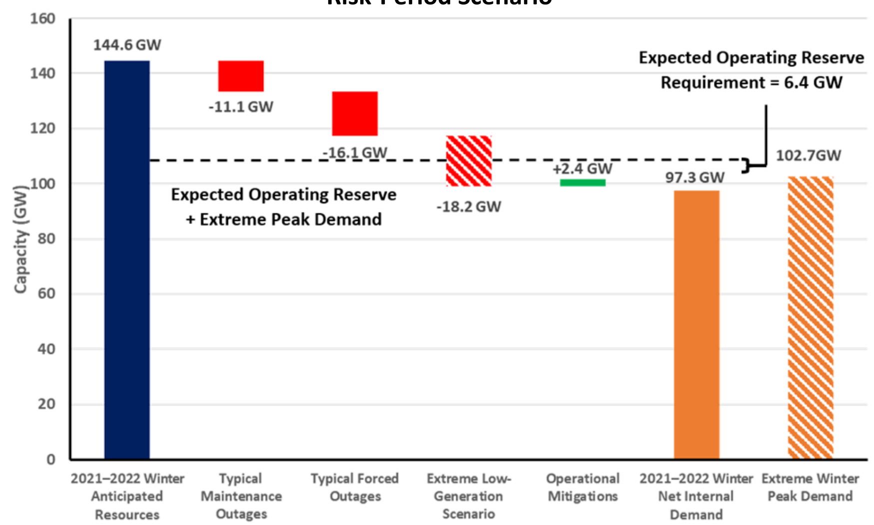
On-Peak Reserve Margins



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 to employ operating mitigations (i.e., demand response and transfers) and EEAs, including load shed, may be needed under extreme peak demand and outage scenarios studied.

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

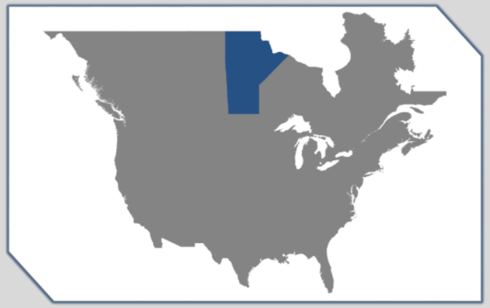
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

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

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

Extreme Derates: Maximum of last five years of outages

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

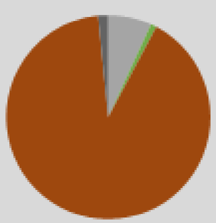


MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to about 580,000 customers throughout Manitoba and natural gas service to about 282,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million in an area of 250,946 square miles.

Manitoba Hydro is winter-peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

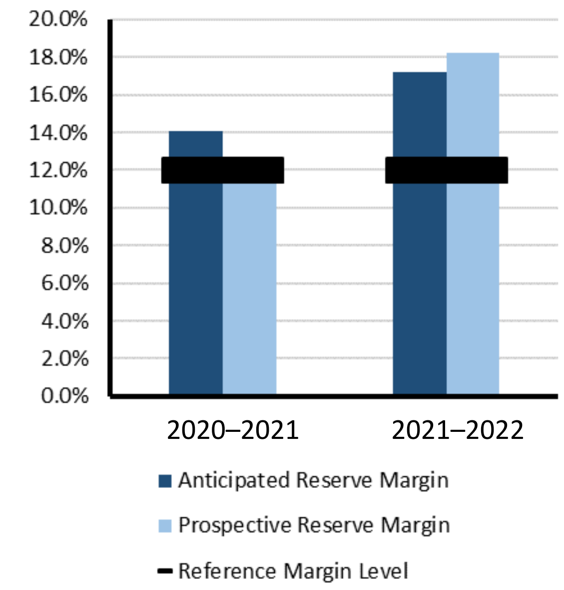
On-Peak Fuel Mix



Highlights

- The Manitoba Hydro assessment area has no COVID-19 related reliability issues for the upcoming season. As of the beginning of September 2021, the COVID-19 Pandemic situation in Manitoba appears stable with the implementation of provincial health orders. While the COVID-19 Pandemic is expected to be present over the winter assessment period, as a result of corporate due diligence, impacts on BPS reliability are not anticipated.
- Although water supply conditions are below average in the southern portion of the watershed supplying Manitoba Hydro hydroelectric generation, reservoir storage levels are adequate to withstand the reoccurrence of the worst drought in its 109-year hydraulic record
- Three Keeyask units are operational and by the end of the year, two additional units are expected to be in service (93 MW per unit).

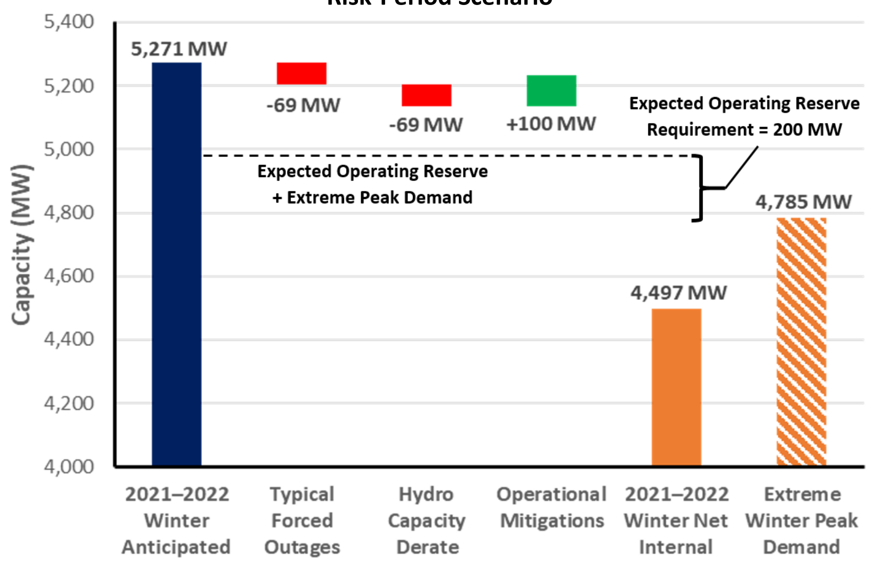
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Risk-Period Scenario



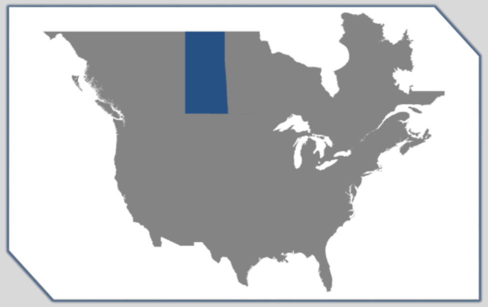
Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and minimum probability of exceedance forecast load

Outages: Accounts for average forced outages, including 69 MW of reduced generation capacity due to drought conditions

Operational Mitigations: Recall 100 MW of planned generator maintenance



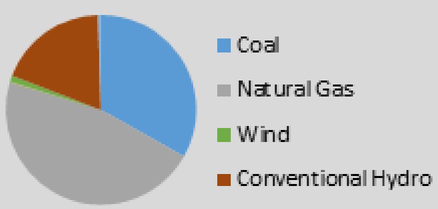
MRO-SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million customers. Peak demand is experienced in the winter.

The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator 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.

On-Peak Fuel Mix



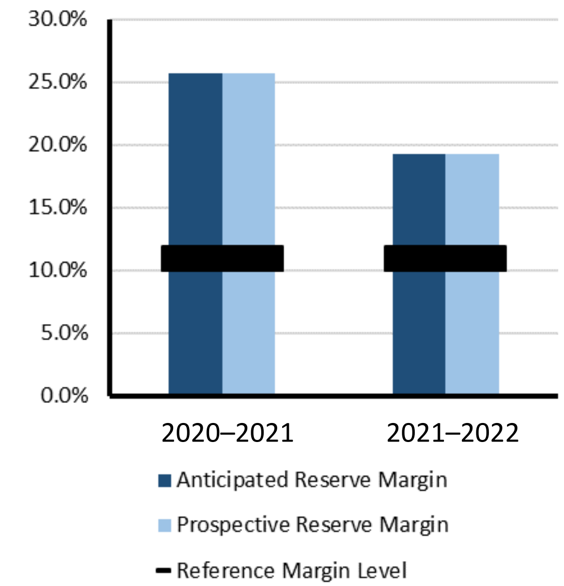
Highlights

- Saskatchewan experiences peak load in winter as a result of extreme cold weather
- SaskPower conducts an annual winter joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues
- The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outage occurs during peak load times combined with planned transmission tie-line maintenance work or generation maintenance work scheduled during winter months
- In case of extreme winter conditions combined with large generation forced outages, SaskPower would utilize available demand response programs, short-term power transfers from neighboring utilities, and short-term load interruptions

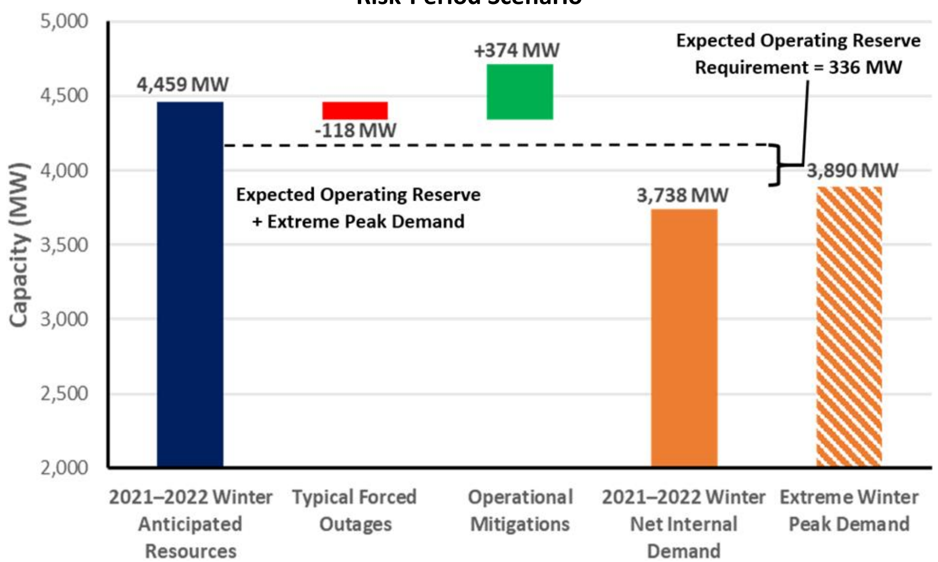
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario

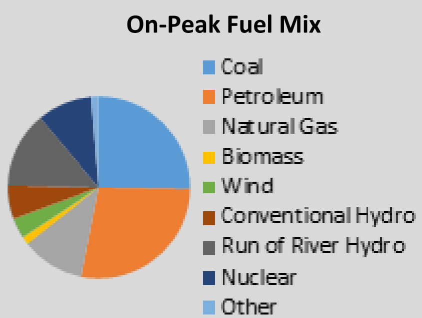


Scenario Description (See [Data Concepts and Assumptions])

- **Risk Period:** Highest risk for unserved energy at peak demand hour
- **Demand Scenarios:** Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads
- **Maintenance Outages:** Average of planned maintenance outages for the winter months of December–February over the past three years
- **Forced Outages:** Estimated using SaskPower forced outage model
- **Operational Mitigations:** Estimated average value based on short term transfer capability from neighboring utilities for the upcoming 2021–2022 winter

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BA. 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.

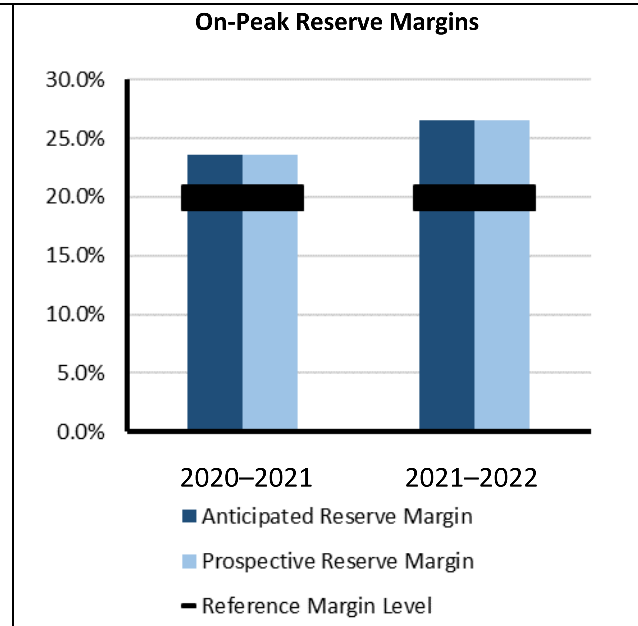


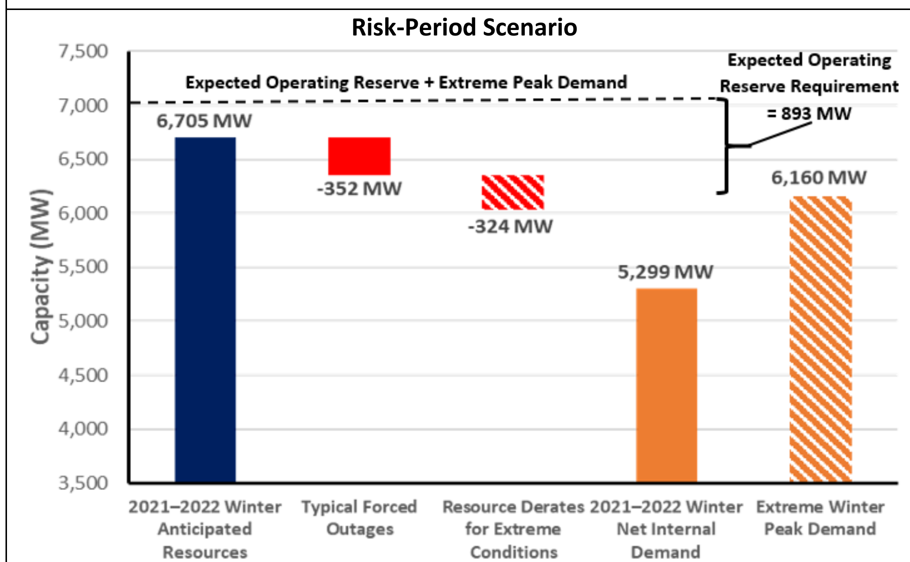
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the winter operating period.
- The Maritimes area is a winter-peaking system.
- As part of the planning process, 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.
- The effects of the COVID-19 pandemic on load patterns, energy usage, and peak demands will continue to be evaluated.

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 to employ operating mitigations (i.e., demand response and transfers) and EEAs, including load shed, may be needed under extreme peak demand and outage scenarios studied.





Scenario Description (See Data Concepts and Assumptions)

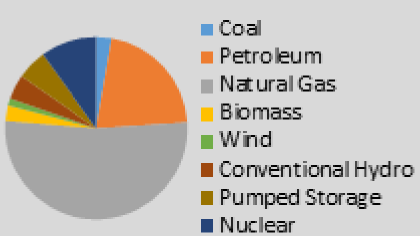
- **Risk Period:** Highest risk for unserved energy at peak demand hour
- **Demand Scenarios:** Net internal demand (50/50) and (99/1) extreme demand forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** A low-likelihood scenario resulting in no wind resources

NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves the six New England states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administers the area's wholesale electricity markets, and manages the comprehensive planning of the regional BPS.

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

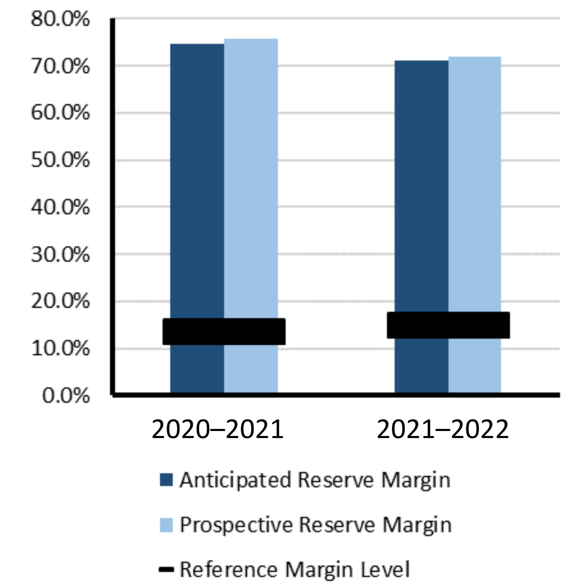
On-Peak Fuel Mix



Highlights

- ISO-NE expects to have sufficient resources to meet the 2021–2022 winter peak demand forecasts of 20,349 MW (90/10) and 20,988 MW (Above 90/10), for the weeks beginning January 3, January 10, and January 17, 2021.
- While ISO-NE meets its regional resource adequacy requirements this 2021–2022 winter operating period, a previously identified/standing concern is whether there will be sufficient electrical energy available to satisfy electricity demand while maintaining operating reserves during an extended cold spell or a series of cold spells given the existing resource mix and fuel delivery infrastructure.
- In regards to potential impacts of the COVID-19 pandemic on the BPS, ISO-NE staff continue to stay in contact with system operators in other parts of the country/world to hear what they're experiencing and how it might apply in New England and vice versa.

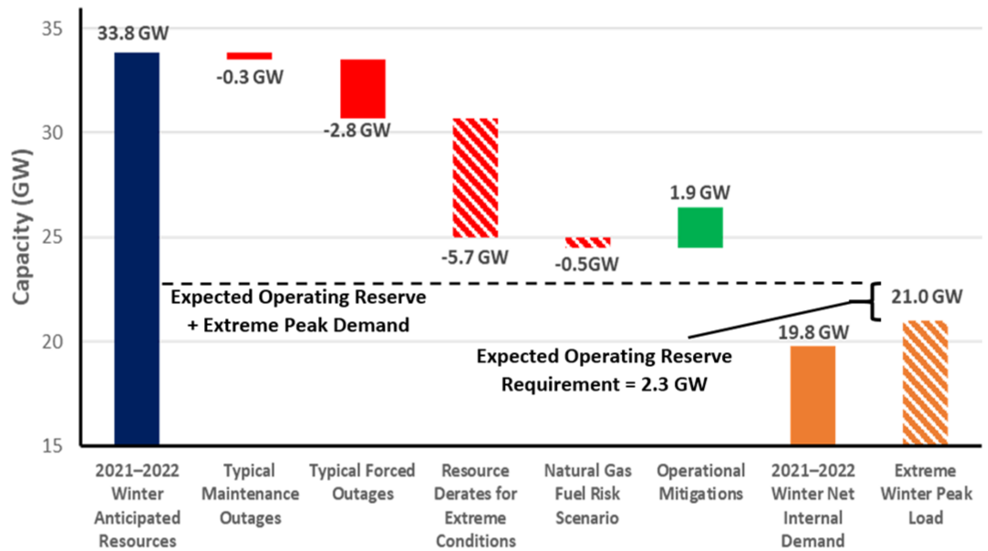
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Risk-Period Scenario

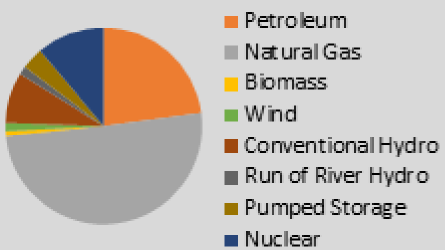


Scenario Description (See Data Concepts and Assumptions)

- **Risk Period:** Highest risk for unserved energy at peak demand hour
- **Demand Scenarios:** Net internal demand (50/50) and demand forecast for coldest day from the last 25 years
- **Outages:** Based on weekly averages
- **Derates:** 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

The New York Independent System Operator (NYISO) is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The New York Independent System Operator (NYISO) is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. New York experienced its all-time peak demand of 25,738 MW in Winter 2013-2014. The established Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2021–2022 IRM at 18.2%."

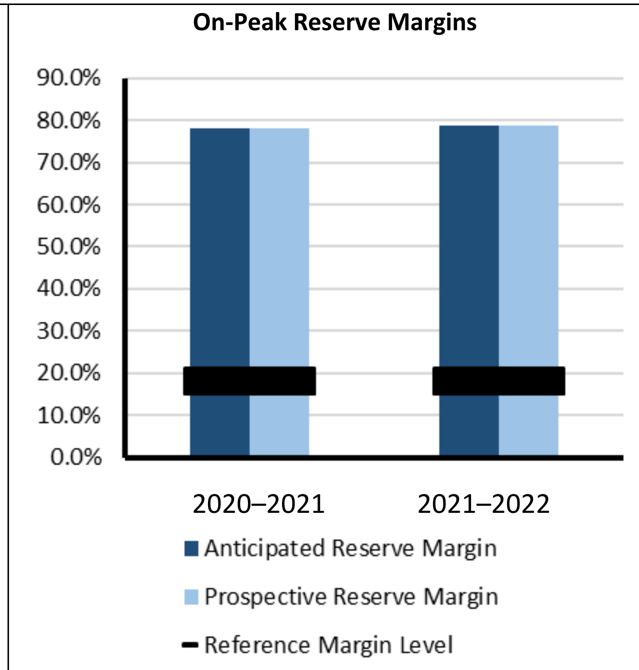


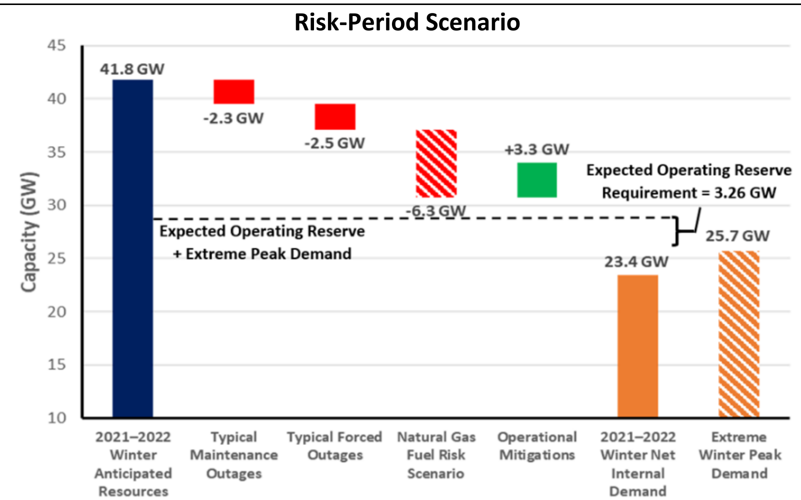
Highlights

New York is a summer peaking area and no emerging reliability issues are anticipated during the 2021–2022 winter assessment period. Surplus capacity margins above the NYISO's operating reserve requirements are projected.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





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 with demand response adjustments

Maintenance Outages: Based on planned scheduled maintenance

Forced Outages: Based on historical 5-year averages

Natural Gas Fuel Risk Derate: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather

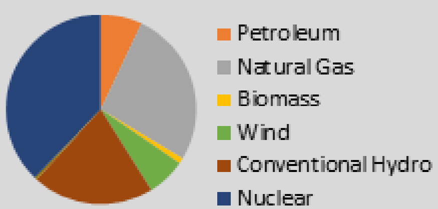
Operational Mitigations: 3.3 GW based on operational/emergency procedures in area *Emergency Operations Manual*

NPCC-Ontario

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 14 million.

Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

On-Peak Fuel Mix



Highlights

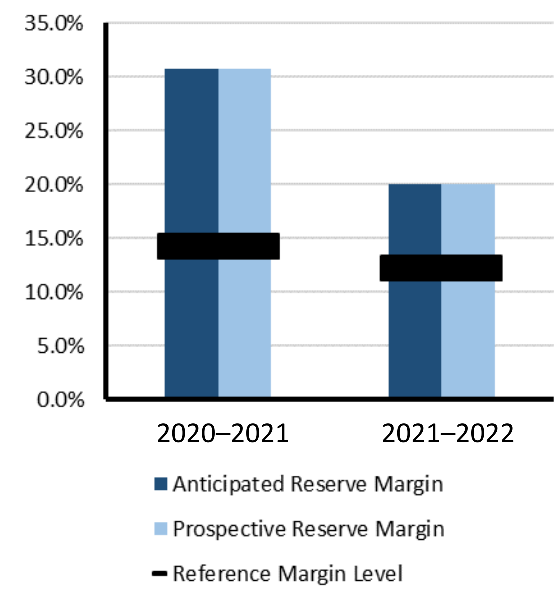
IESO anticipates that it will maintain reliability on its system through Winter 2021–2022.

Nuclear refurbishment schedules and other nuclear and hydroelectric planned outages will reduce generation capacity for the coming winter season; however, IESO expects to have sufficient generation supply to meet demand.

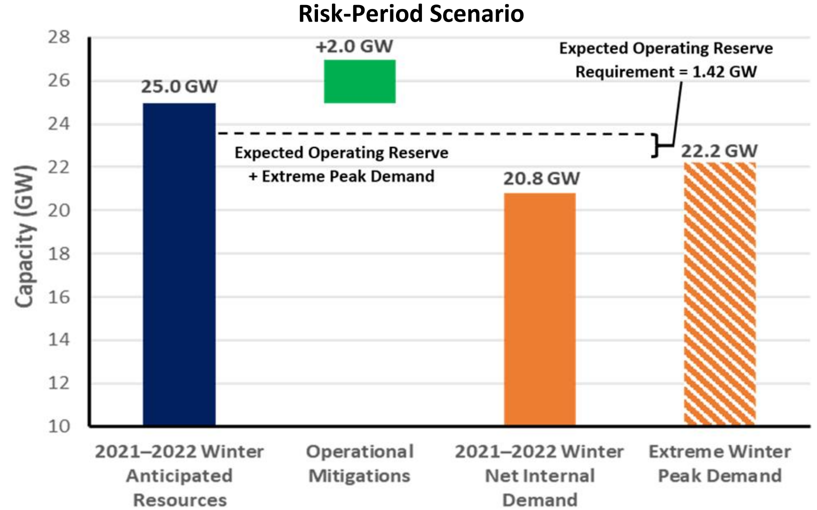
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



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

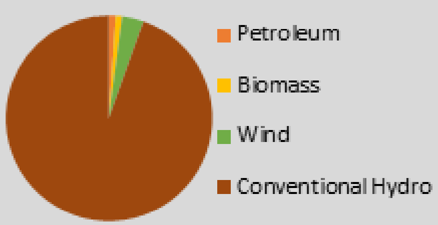
Operational Mitigations: Imports anticipated from neighbors during emergencies

NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million.

Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

On-Peak Fuel Mix



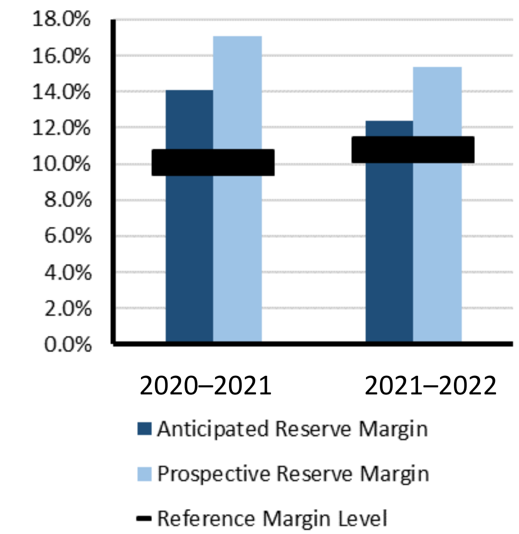
Highlights

- Québec predicts that it will maintain system resource adequacy this winter.
- The Québec area is a winter-peaking system with predominately hydroelectric generation resources. Adequate capacity margins above its reference reserve requirements are projected for the 2021–2022 winter assessment period.
- No changes have been made to the assessment area's winter preparedness programs.

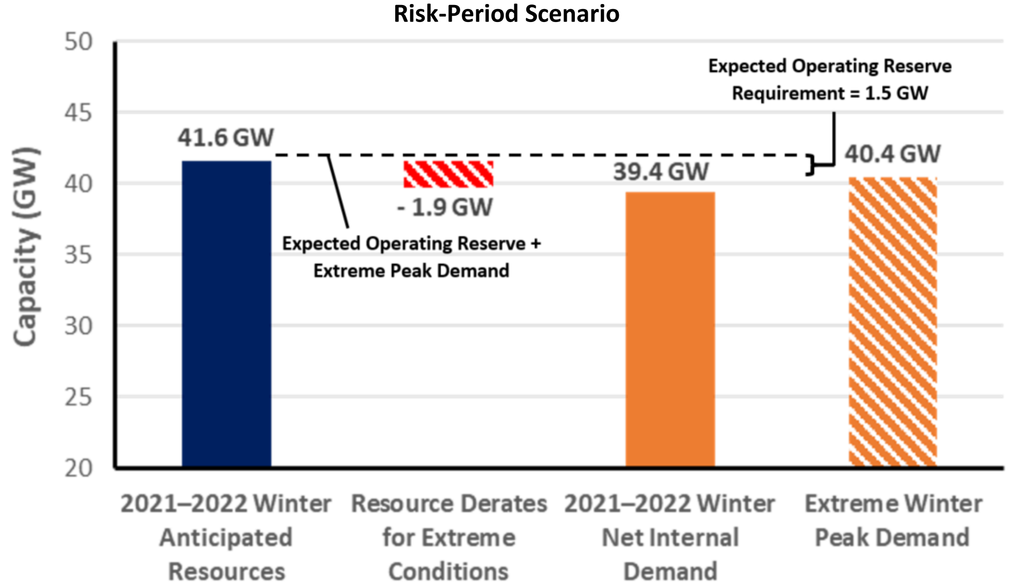
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Québec plans to use short-term capacity purchases in order to meet capacity requirements when needed. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs, including load shed that may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

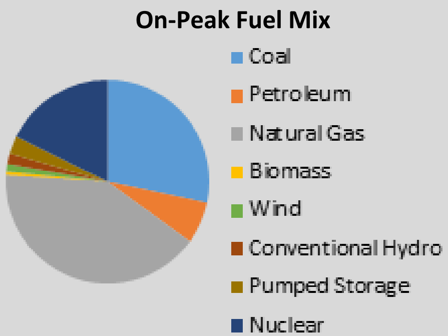
Demand Scenarios: Net internal demand (50/50) and (96/4) demand forecast

Extreme Derates: Rare scenario of 1,850 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 Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

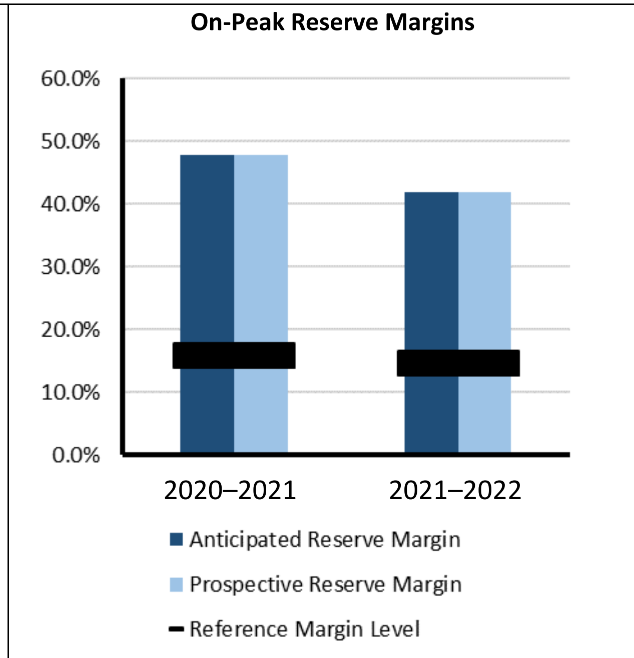


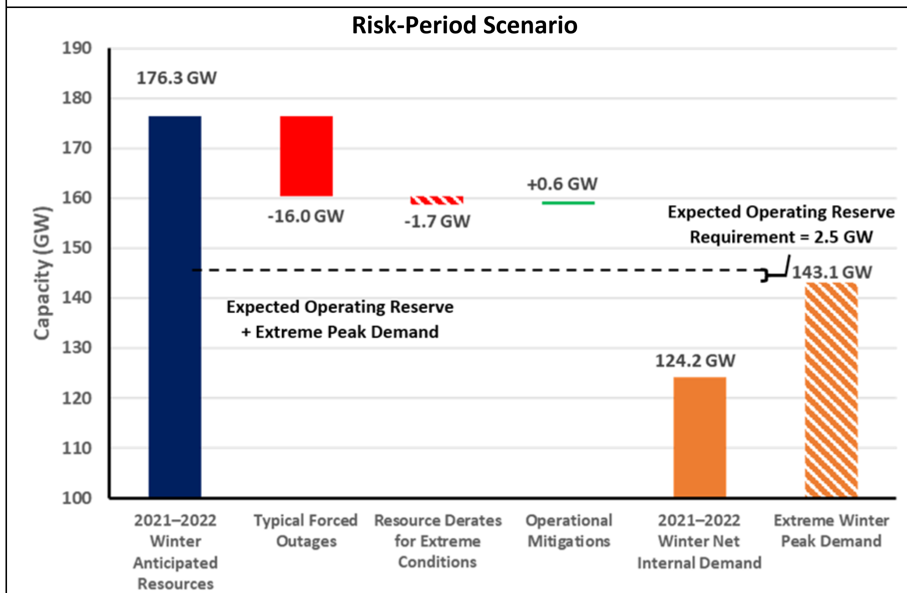
Highlights

- PJM expects no resource problems over the entire 2021–2022 winter peak season because installed capacity is almost three times the reserve requirement.
- As a result of increasing reports of existing and future supply shortages of fuel and non-fuel consumables going into the 2021–2022 winter season, PJM has initiated a generation resource weekly fuel inventory and supply data request. The weekly requests start October 11, 2021 and will run through February 28, 2022, and apply to all coal and oil resources (including dual-fuel units).
- No other reliability concerns are expected.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





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

Outages: Based on historical data and trending

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

Operational Mitigations: A total of 0.6 GW based on operational/emergency procedures

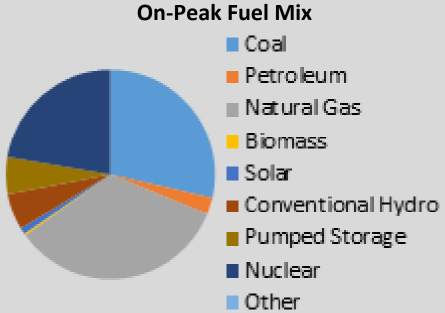
SERC-East

SERC-East is a summer-peaking assessment area within the SERC RE. SERC-East includes North Carolina and South Carolina.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



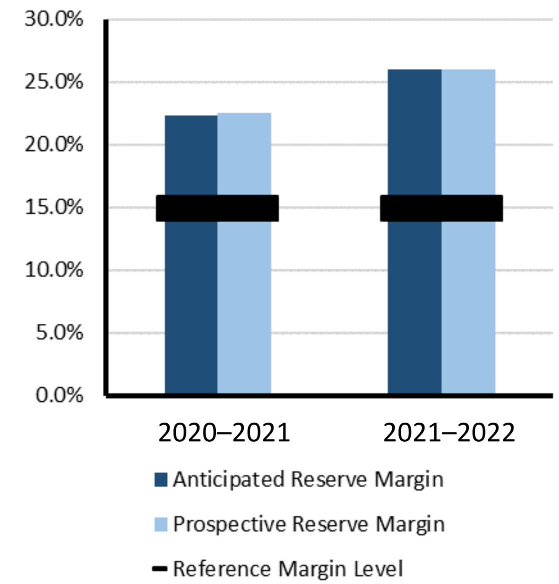
Highlights

- SERC-East entities have not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC-East entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities in SERC-East reported they have an extensive weatherization process that includes developing procedures specific to freezing events.

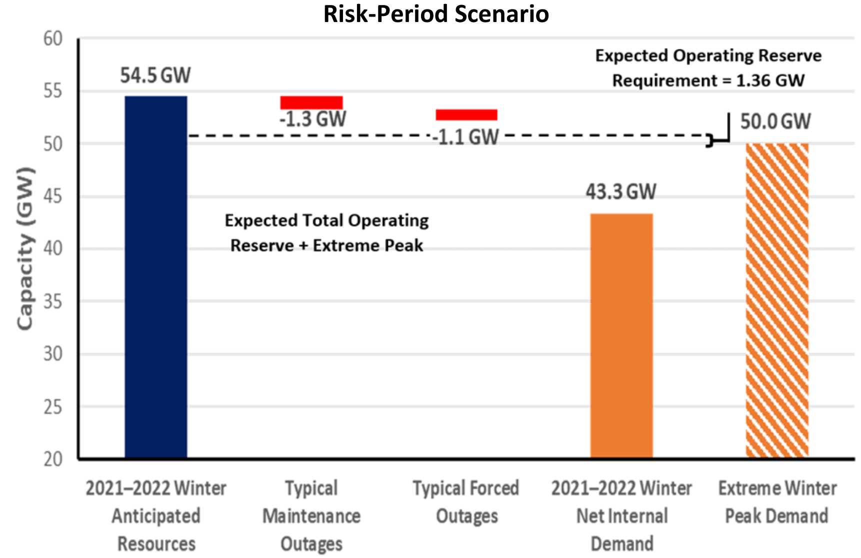
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



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:** Weighted average forced outage rates on-peak are factored into the anticipated resources calculation
- **Extreme Derates:** Accounts for reduced thermal capacity contributions due to performance in extreme conditions

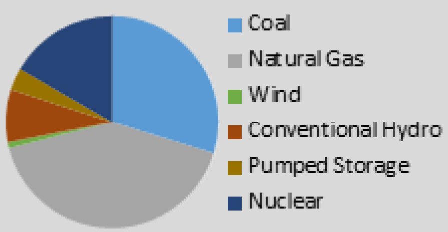
SERC-Central

SERC-Central is a summer peaking assessment area within the SERC RE. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky.

SERC-Central is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



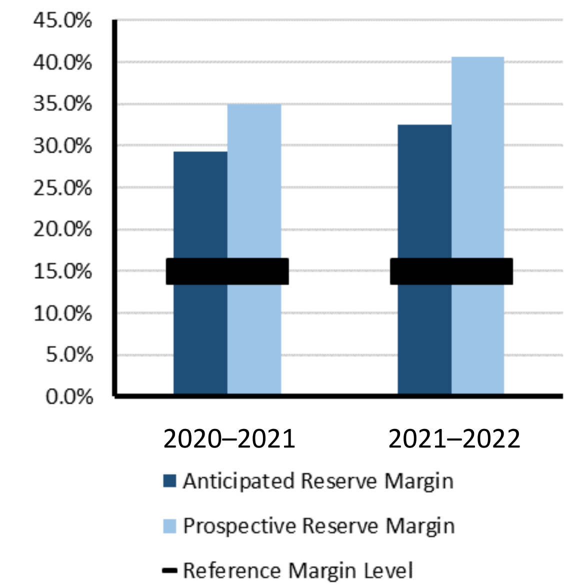
Highlights

- SERC-Central entities have not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC-Central entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities in SERC-Central reported they have an extensive weatherization process that include developing procedures specific to freezing events.

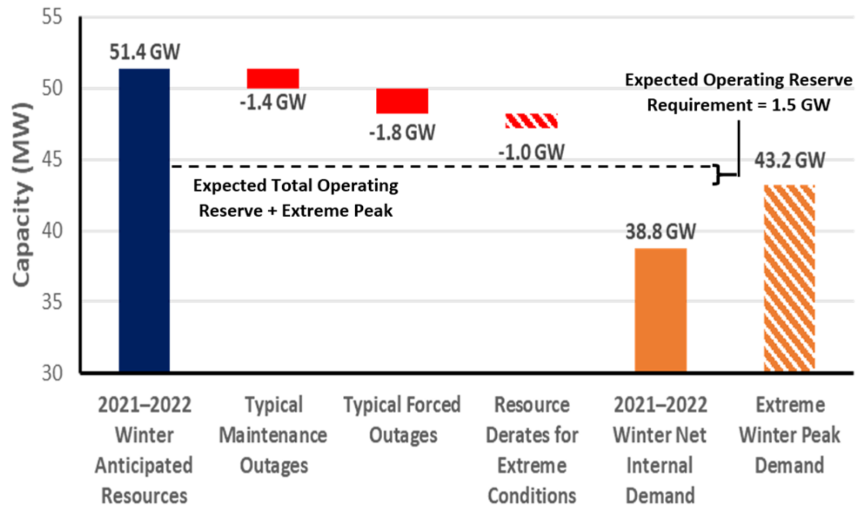
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



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

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

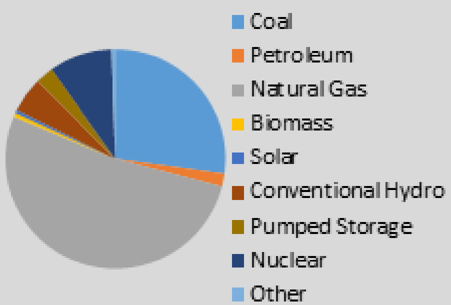
SERC-Southeast

SERC-Southeast is a summer peaking assessment area within the SERC RE. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



Highlights

SERC-Southeast entities have not identified any emerging or potential reliability issues for the upcoming winter season.

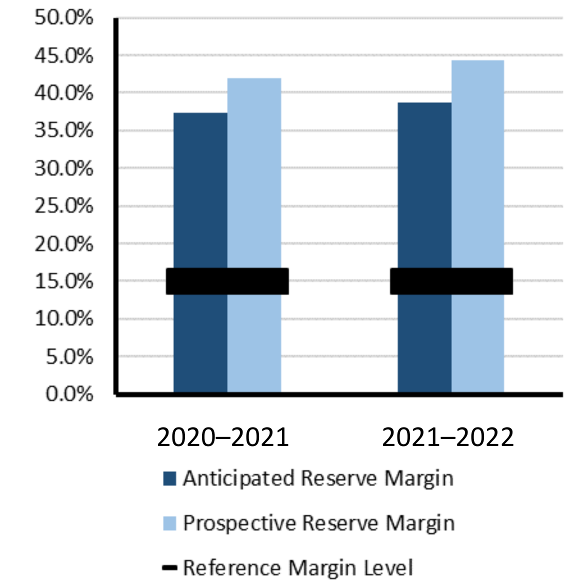
Grid operators are monitoring coal resource availability. Stockpiles are sufficient for anticipated conditions and usage. However, a colder than normal winter could lead to higher coal consumption and need for operators to manage generator run times to maintain adequate stockpiles.

Many entities in SERC-Southeast reported they have an extensive weatherization process that include developing procedures specific to freezing events.

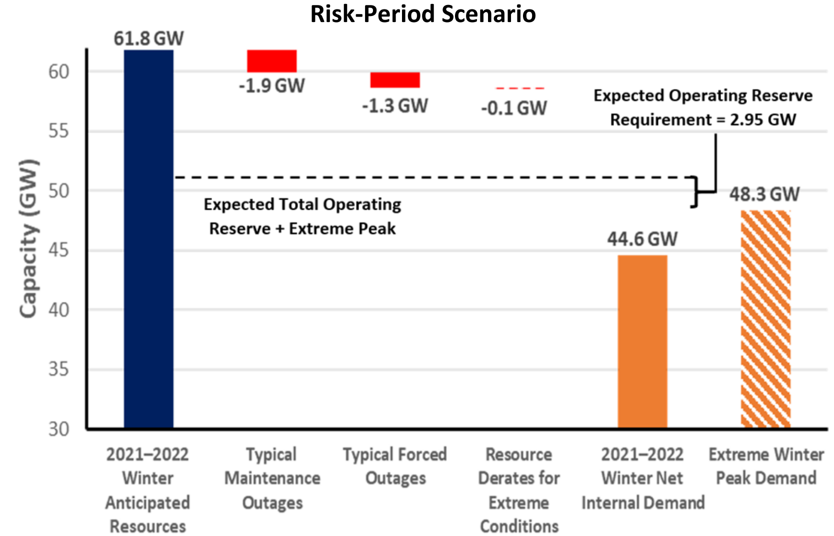
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



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

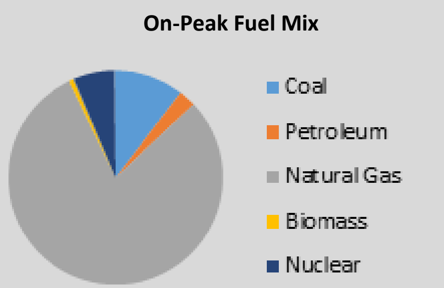
Forced Outages and Extreme Derates: All outages and derates are factored into the anticipated resources calculation

SERC-Florida Peninsula

SERC-Florida Peninsula is a summer peaking assessment area within SERC.

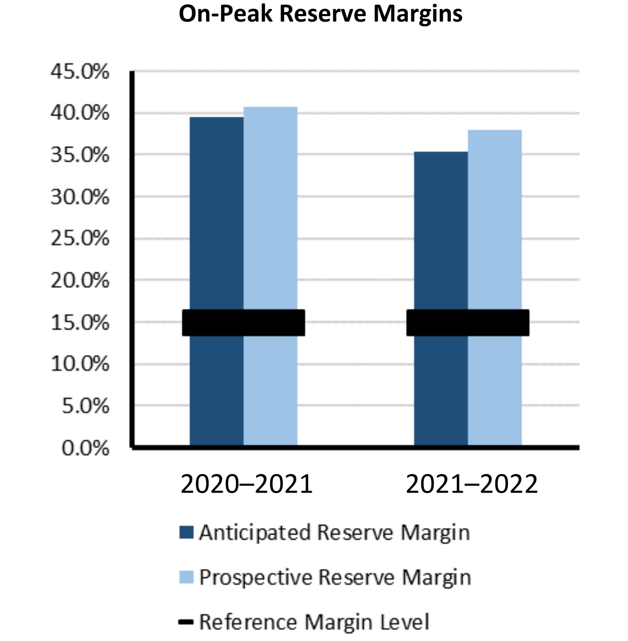
SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC RE includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.



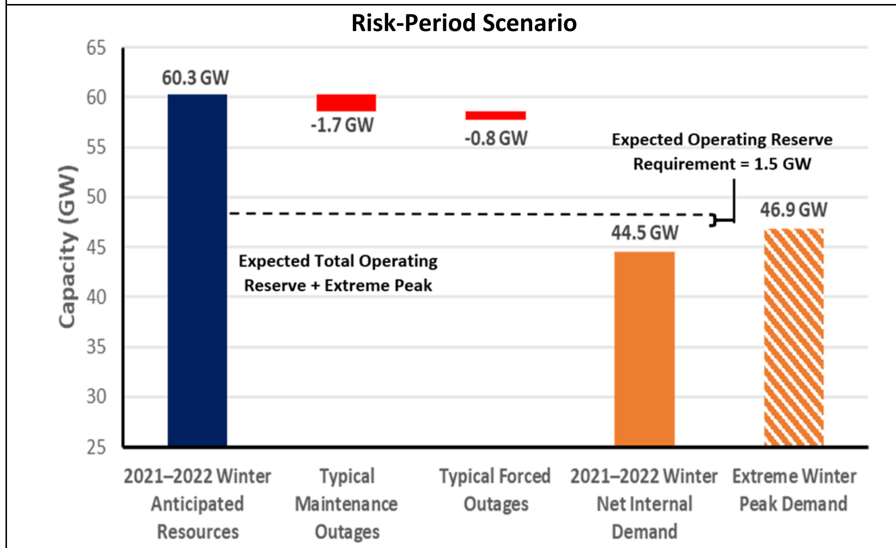
Highlights

- SERC-Florida Peninsula entities have not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC-Florida Peninsula entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities in SERC-Florida Peninsula reported they have an extensive weatherization process that include developing procedures specific to freezing events.



Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.



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

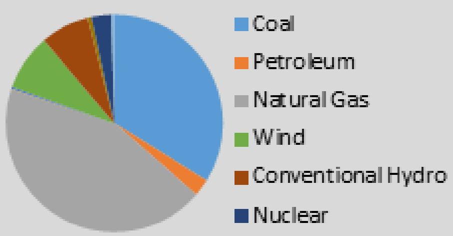
Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

SPP

Southwest Power Pool (SPP) Planning Coordinator 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 Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization RE and the WECC RE. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

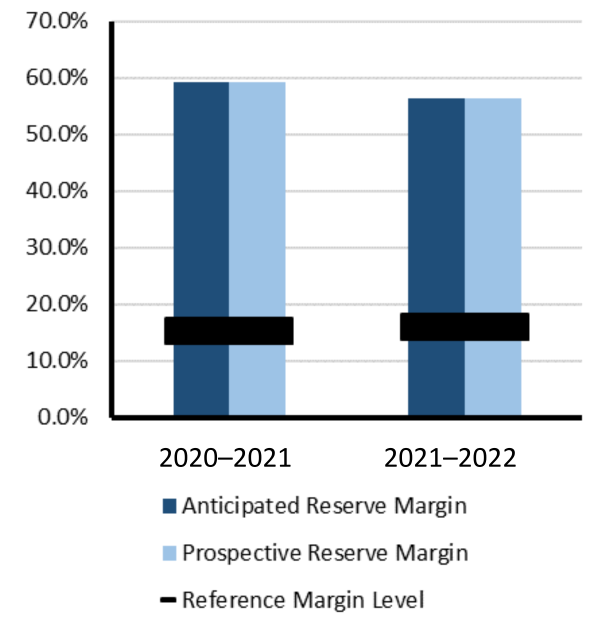
On-Peak Fuel Mix



Highlights

- SPP anticipates planning reserves are adequate for the upcoming winter season. SPP hosted a winter workshop in October.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2021–2022 winter season but realizes that interruptions to fuel supply could create unique operation challenges.
- SPP continues working with neighboring areas to address potential electricity deliverability issues associated with extreme weather events. Efforts are aimed at enhancing communications and operator preparedness.
- In an effort to minimize conservative operations periods, EEAs, and to respond to mid-range wind forecast uncertainty, SPP created mitigation processes to deal with high impact areas of concern. SPP has developed operational mitigation teams, processes, and procedures that have been put in place to maintain real-time reliability needs.
- SPP has created the Improved Resource Availability Task Force, which will take primary responsibility for addressing Tier 1 recommendations related to fuel assurance and resource planning and availability identified in the ***Comprehensive Review of SPP's Response to the February 2021 Winter Storm*** report as approved by the July 26, 2021, SPP Board of Directors Meeting.

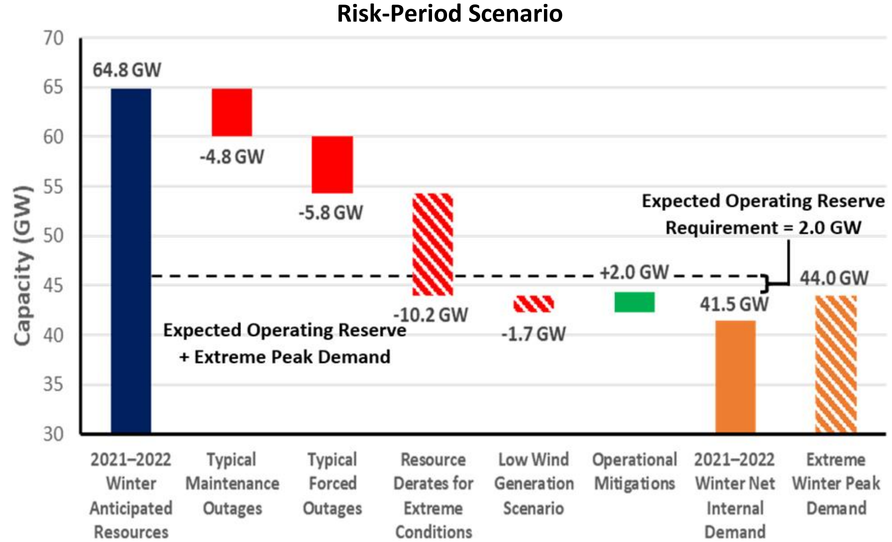
On-Peak Reserve Margins



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 to employ operating mitigations (i.e., demand response and transfers) and EEAs, including load shed that may be needed under extreme peak demand and outage scenarios studied.

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 based on winter storm Uri demand projection

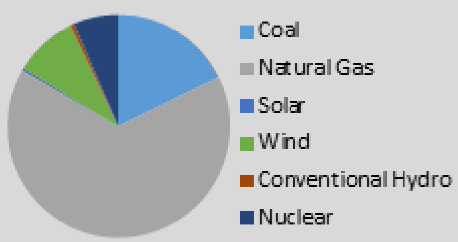
Operational Mitigations: A total of 2 GW based on operational/emergency procedures (External Assistance)

Texas RE-ERCOT

The Electric Reliability Council of Texas (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 a summer-peaking RE that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has over 710 generation units, and serves more than 25 million customers. Lubbock Power & Light joins the ERCOT grid on June 1, 2021. Texas RE is responsible for the RE functions described in the *Energy Policy Act of 2005* for the ERCOT RE.

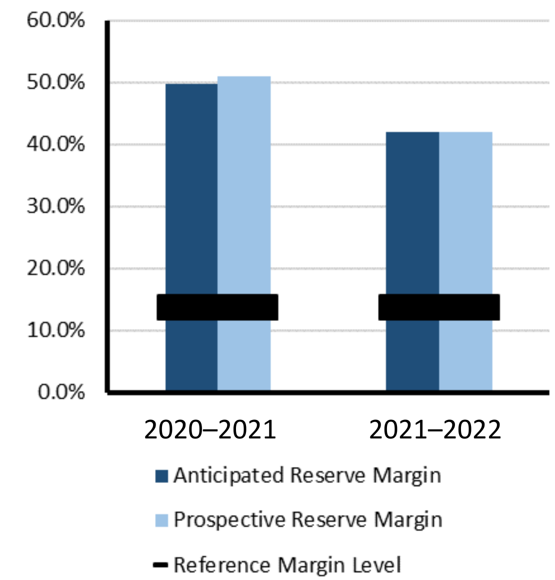
On-Peak Fuel Mix



Highlights

- With an Anticipated Reserve Margin of 42%, capacity reserves for the Texas RE-ERCOT area are sufficient to meet forecasted peak demand and to cover the types of severe weather events regularly experienced in the area.
- Probabilistic risk assessment for the upcoming winter season confirms a low probability of energy emergency events occurring during the expected peak load hour (hour-ending 8:00 a.m. local time). The assessment accounts for the risk of another weather event like winter storm Uri.
- In August, the Public Utility Commission of Texas published a draft rule for generation and transmission facility weatherization standards. By the end of 2021, entities must complete certain winter weather emergency preparations. ERCOT is required to conduct inspections and issue compliance reports with specifying a period to cure compliance deficiencies.
- Regulators and the electricity and natural gas industries have made progress to identify critical natural gas supply infrastructure for electricity generation. Since February, electricity transmission and distribution providers report that the number of natural gas facilities that are registered as critical loads to support electricity generation increased from 64 to 1,290 as of August.

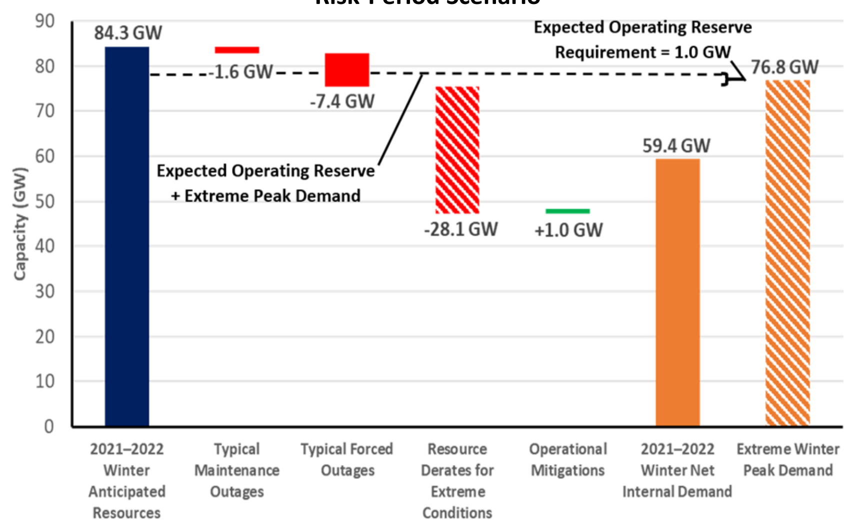
On-Peak Reserve Margins



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 to employ operating mitigations (i.e., demand response and transfers) and EEAs, including load shed that may be needed under extreme peak demand and outage scenarios studied.

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

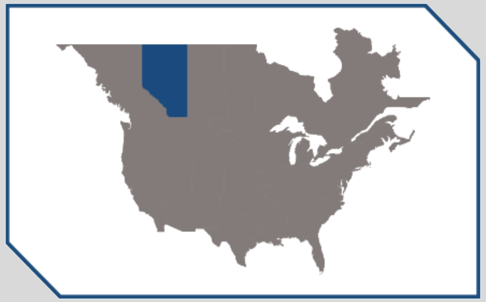
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme winter peak demand based on 2020–2021 winter storm Uri peak demand

Maintenance and Forced Outages: Based on the historical averages of maintenance or forced outages respectively for December through February weekdays, hours ending 7:00–10:00 a.m. local time for the last three (2018/19, 2019/20, and 2020/21) winter seasons (winter storm Uri-related forced outages between February 15–18, 2021 were excluded from this calculation due to the storm being an outlier event.)

Extreme Derates: Based on the February 2021 winter storm Uri event: 17,991 MW (thermal), 7,927 MW (wind), 663 MW (PV), and 1,499 MW from Private Use Network generation

Operational Mitigations: Additional capacity from switchable generation, additional imports, and voltage reduction



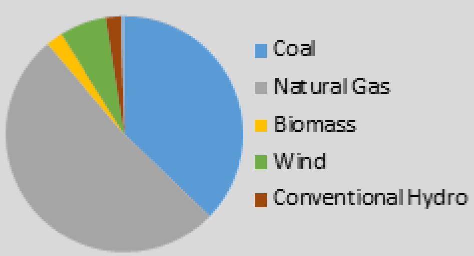
WECC-NWPP-AB

WECC-NWPP-AB (Alberta) is an assessment area in the WECC RE that consists of the province of Alberta, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



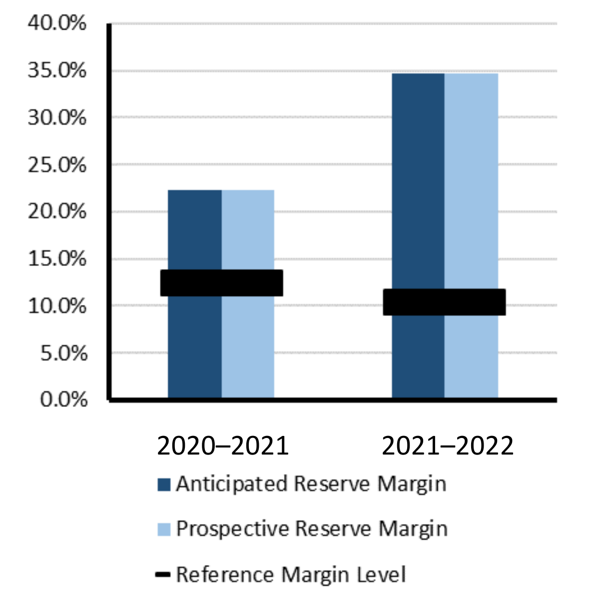
Highlights

WECC's modeling indicates that its assessment areas and all zones within the footprint will meet or exceed their respective Reference Margin Level given expected peak demand and expected resource availability as well as most low resource availability and extreme peak demand scenarios, maintaining resource adequacy on-peak through the 2021–2022 winter season.

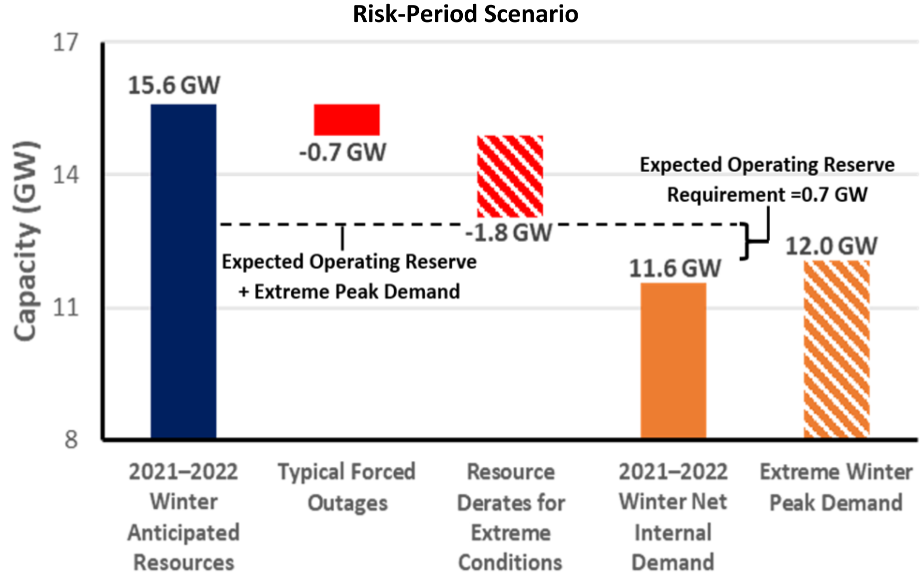
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



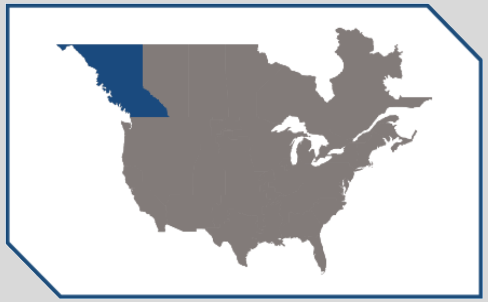
Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

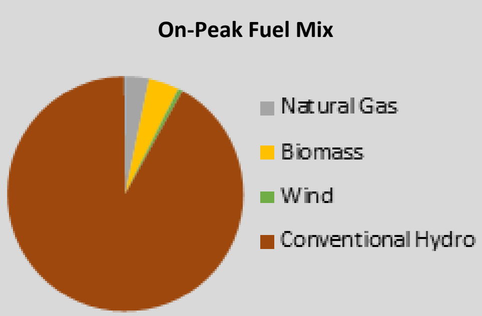


WECC-NWPP-BC

WECC-NWPP-BC (British Columbia) is an assessment area in the WECC RE that consists of the province of British Columbia, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

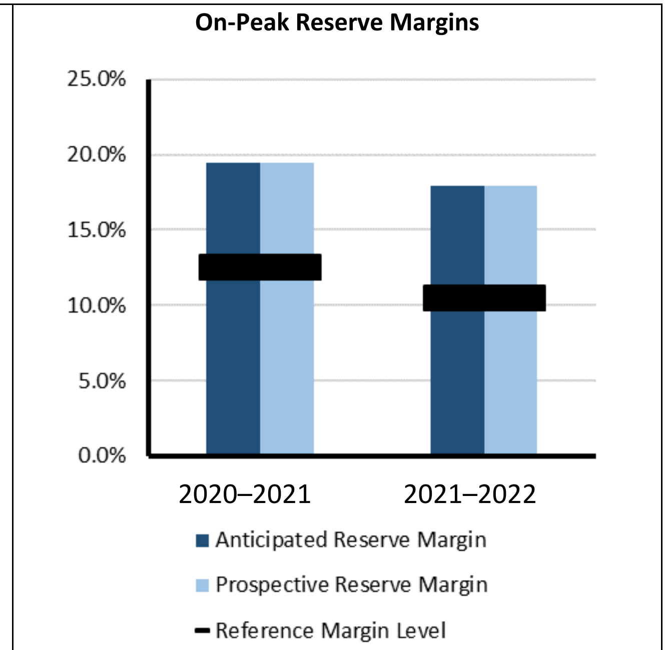


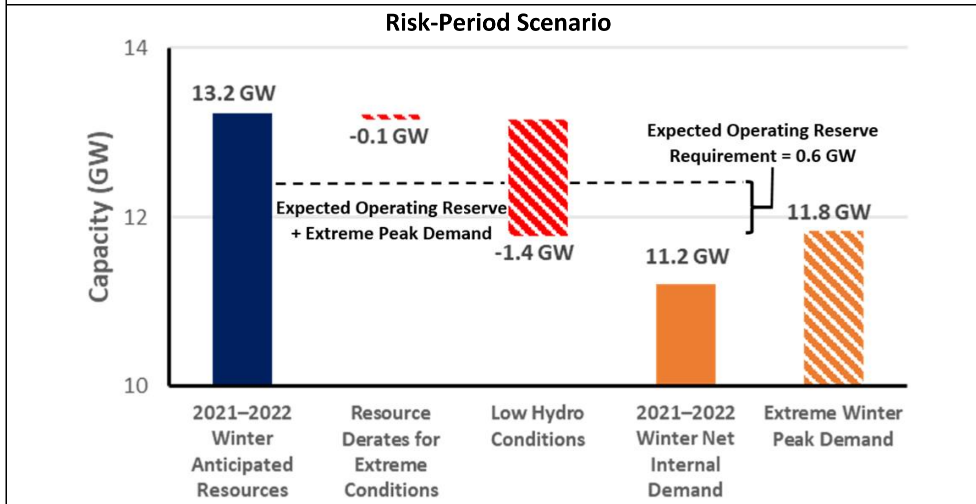
Highlights

- WECC's modeling indicates that its assessment areas and all zones within the footprint will meet or exceed their respective Reference Margin Level given expected peak demand and expected resource availability as well as most low resource availability and extreme peak demand scenarios, maintaining resource adequacy on-peak through the 2021–2022 winter season.

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 to employ operating mitigations (e.g., demand response, transfers, and short-term load interruption) and EEAs may be needed under extreme peak demand and outage scenarios studied.





Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

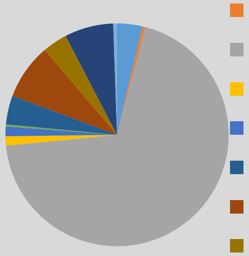
WECC-CA/MX

WECC-CA/MX (California-Mexico) is an assessment area in the WECC RE that includes parts of California, Nevada, and Baja California, Mexico.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorizes, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

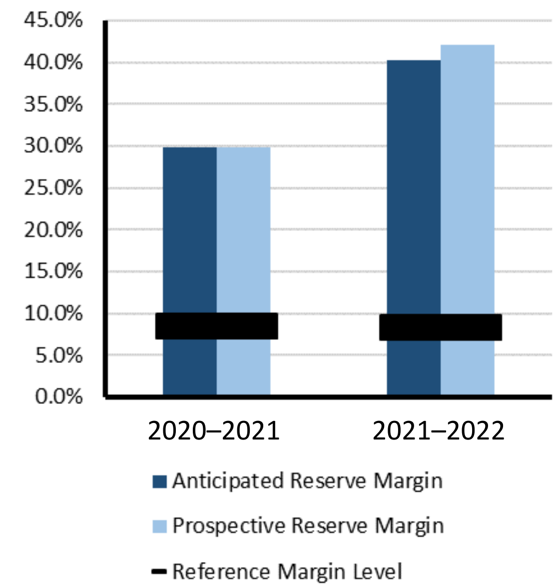
On-Peak Fuel Mix



Highlights

- WECC's modeling indicates that its assessment areas and all zones within the footprint will meet or exceed their respective Reference Margin Level given expected peak demand and expected resource availability as well as most low resource availability and extreme peak demand scenarios, maintaining resource adequacy on-peak through the 2021–2022 winter season.
- A rupture on the El Paso interstate natural gas pipeline in August has caused an outage that reduces the amount of natural gas flowing into California. Natural gas storage levels in the area will decline during periods of high demand while the outage persists. Electricity reliability would not be affected in average temperatures and conditions, however prolonged periods of cold temperatures could result in curtailment of natural gas fuel to generators. The present low-hydro conditions in the west also increase reliance on natural gas generation and can strain natural gas storage levels.[17]

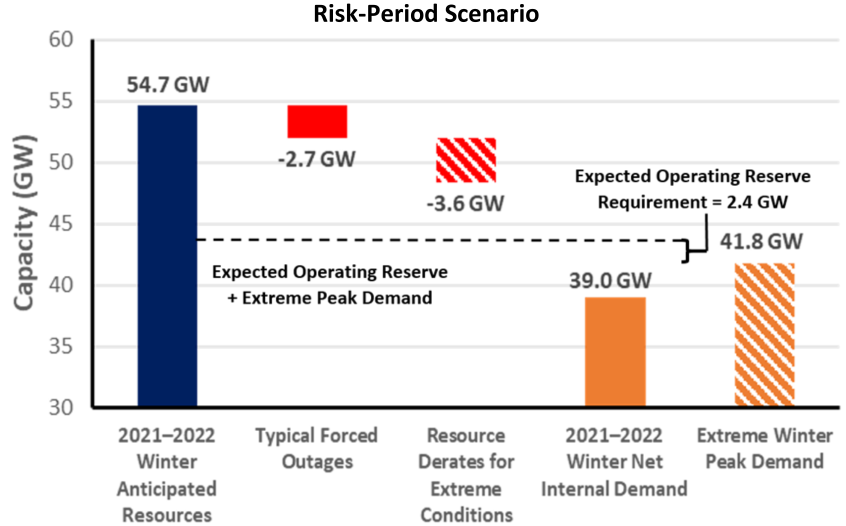
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

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: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historic data and manufacturer data for temperature performance and outages

[17] See California Public Utilities Commission *Winter 2021-22 Southern California Reliability Assessment*: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/winter2021-22-reliabilityassessment.pdf

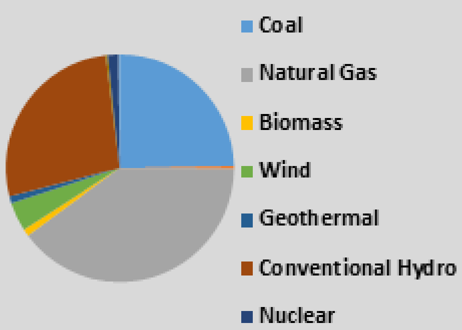
WECC-NWPP-US & RMRG

WECC-NWPP-US & RMRG (Northwest Power Pool & Rocky Mountain Reserve Sharing Group) is an assessment area in the WECC RE. The area 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 in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

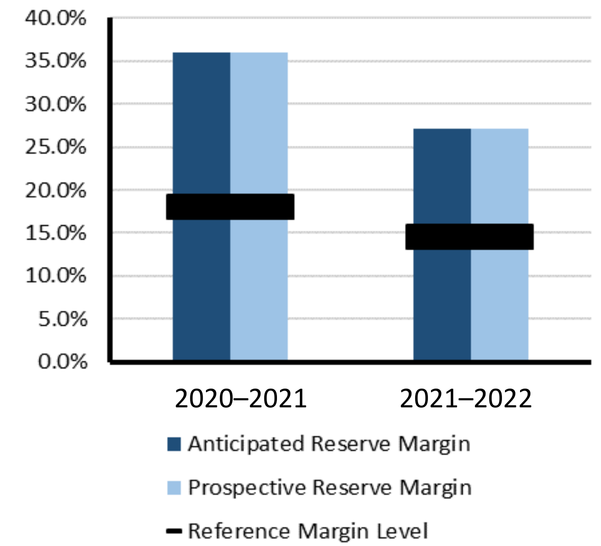
On-Peak Fuel Mix



Highlights

WECC's modeling indicates that its assessment areas and all zones within the footprint will meet or exceed their respective Reference Margin Level given expected peak demand and expected resource availability as well as most low resource availability and extreme peak demand scenarios, maintaining resource adequacy on-peak through the 2021–2022 winter season. However, with NOAA predicting colder temperatures across the Pacific Northwest along with the continued drought, there are some scenarios that will be monitored closely, such as in the NWPP.

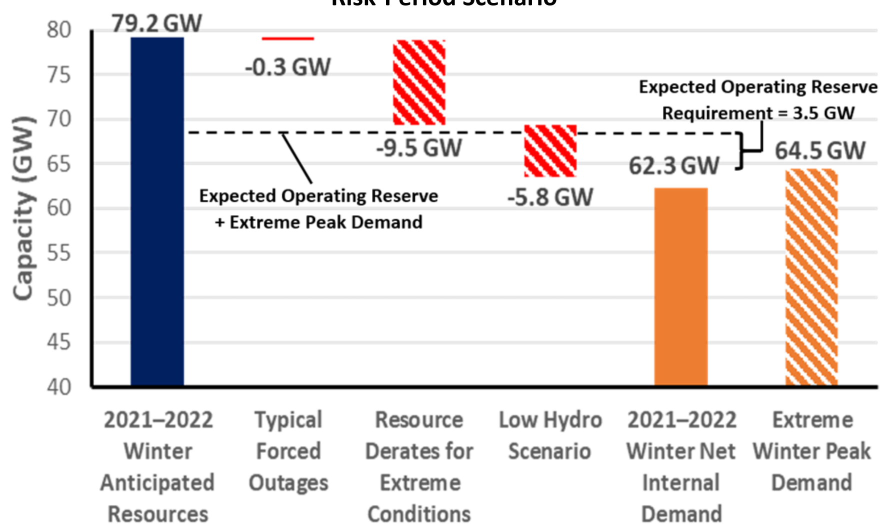
On-Peak Reserve Margins



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 to employ operating mitigations (i.e., demand response and transfers) and EEAs, including load shed, may be needed under extreme peak demand and outage scenarios studied.

Risk-Period Scenario



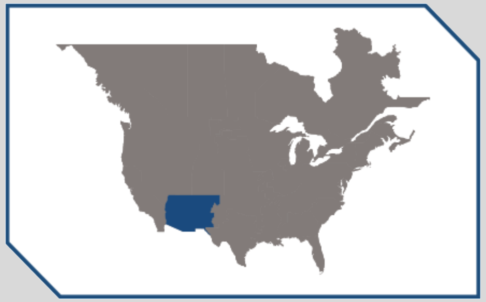
Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

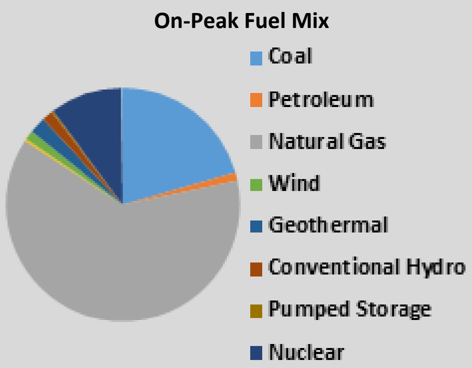


WECC-SRSG

WECC-SRSG (Southwest Reserve Sharing Group) is an assessment area in the WECC RE. It includes Arizona, New Mexico, and part of California and Texas.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 39 Balancing Authorities, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse RE.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

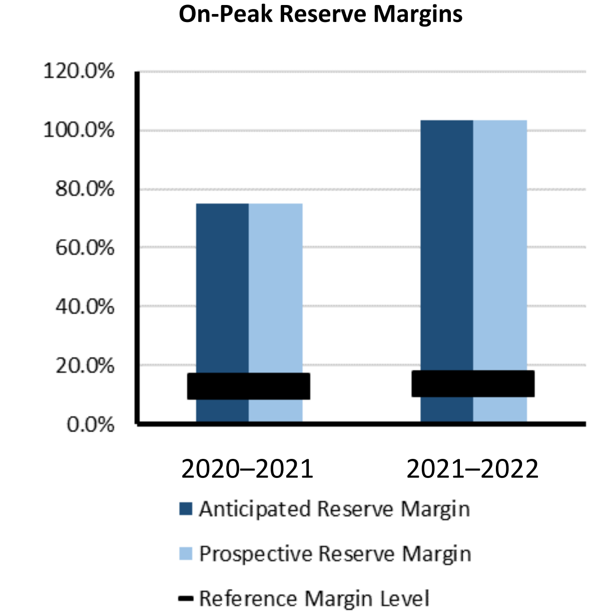


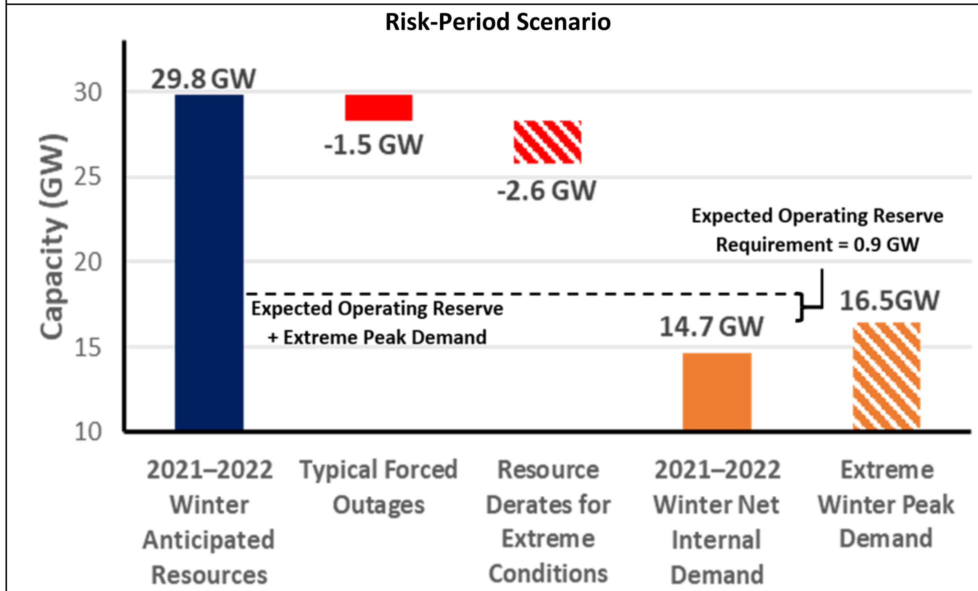
Highlights

WECC's modeling indicates that its assessment areas and all zones within the footprint will meet or exceed their respective Reference Margin Level given expected peak demand and expected resource availability as well as most low resource availability and extreme peak demand scenarios, maintaining resource adequacy on-peak through the 2021–2022 winter season.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description (See [Data Concepts and Assumptions](#))

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

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

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the 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.
• *2021 Long-Term Reliability Assessment* data has been used for most of this 2021–2022 assessment period augmented by updated load and capacity data.
• 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[18] or total internal demand for the summer and winter of each year.[19]
• Total internal demand projections are based on normal weather (50/50 distribution[20]) and are provided on a coincident[21] 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.

[18] *Glossary of Terms* used in NERC Reliability Standards

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

[20] 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.

[21] 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: 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 Reference Margin Level 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 a Reference Margin Level 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, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately 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. Further, 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 Anticipated Reserve Margin, 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.[22] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2021–2022 winter as shown in **Figure 9**. The Canadian winter peaking systems of NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. The potential limited availability of local stored fuel supplies can result in additional generator outages due to depleted fuel inventories. Variable energy resources, such as wind and solar, often contribute significantly less of their installed capability at the period of peak demand in winter. Winter peaks in many areas occur in early morning hours or other times of darkness, resulting in little or no electrical resource output. Consequently the capacity contribution of variable energy resources to an area's anticipated resources may be a fraction of installed capability in winter.

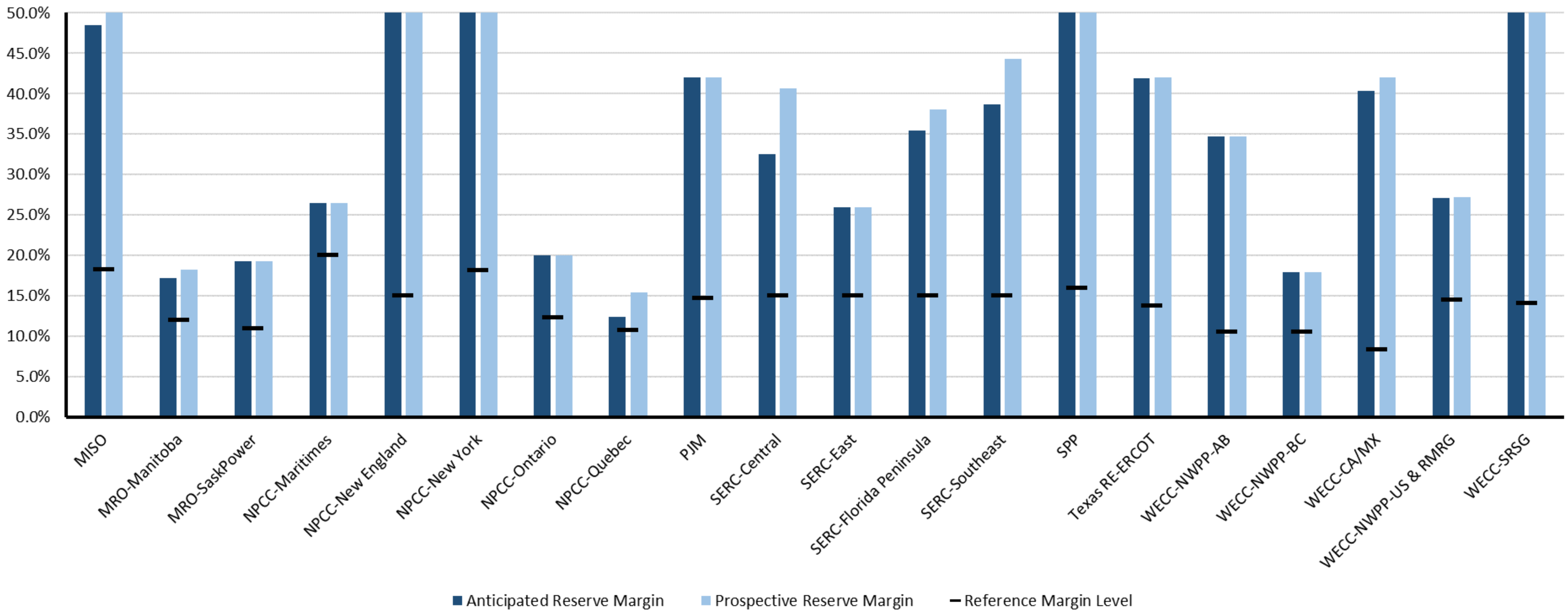
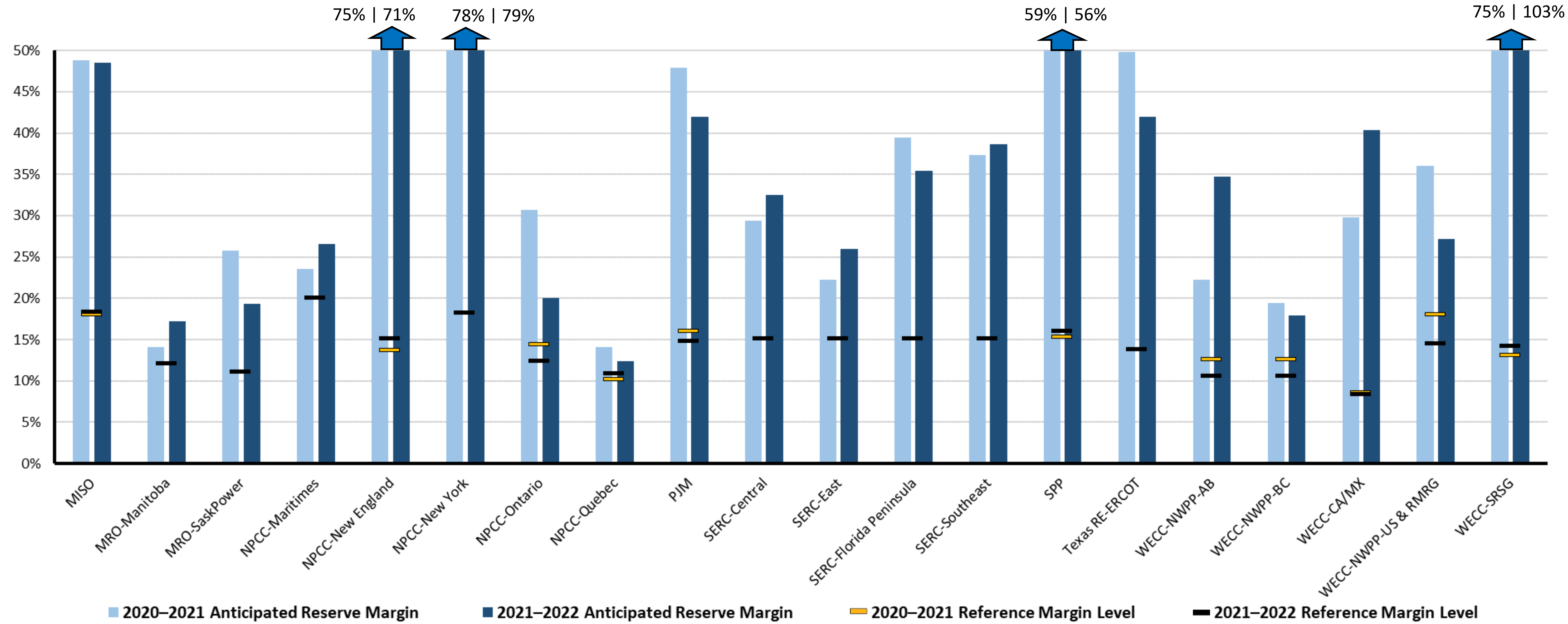


Figure 9: Winter 2021–2022 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[22] 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 Reference Margin Levels.

Changes from Year-to-Year

Figure 10 provides the relative change in the forecast Anticipated Reserve Margins from the 2020–2021 winter to the 2021–2022 winter. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-SaskPower, NPCC-Ontario, and WECC-NWPP-US & RMRG have noticeable reductions in anticipated resources between the 2020–2021 winter and the 2021–2022 winter but remain above their Reference Margin Levels for 2021–2022 winter. The lower Anticipated Reserve Margins for MRO-SaskPower, NPCC-Ontario, and WECC-NWPP-US & RMRG do not result in reliability concerns on peak for this upcoming winter. Additional details are provided in the Data Concepts and Assumptions section.



Note: The areas that only have one bar have the same Reference Margin Level for both years.

Figure 10: Winter 2020–2021 and Winter 2021–2022 Anticipated Reserve Margins Year-to-Year Change

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below (in alphabetical order).

MISO Resource Adequacy Data

Demand, Resource, and Reserve Margins	2020–2021 WRA	2021–2022 WRA	2020–2021 vs. 2021–2022 WRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	103,167	100,812	-2.3%
Demand Response: Available	4,536	3,480	-23.3%
Net Internal Demand	98,631	97,332	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	144,736	138,535	-4.3%
Tier 1 Planned Capacity	574	3738	551.1%
Net Firm Capacity Transfers	1,405	2,283	62.5%
Anticipated Resources	146,715	144,556	-1.5%
Existing-Other Capacity	6,390	0	-100.0%
Prospective Resources	153,557	147,182	-4.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	48.8%	48.5%	-0.3
Prospective Reserve Margin	55.7%	51.2%	-4.5
Reference Margin Level	18.0%	18.3%	0.3

MRO-SaskPower Resource Adequacy Data

Demand, Resource, and Reserve Margins	2020–2021 WRA	2021–2022 WRA	2020–2021 vs. 2021–2022 WRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,618	3,798	5.0%
Demand Response: Available	60	60	0.0%
Net Internal Demand	3,558	3,738	5.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,348	4,321	-0.6%
Tier 1 Planned Capacity	0	13	-
Net Firm Capacity Transfers	125	125	0.0%
Anticipated Resources	4,473	4,459	-0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,473	4,459	-0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.7%	19.3%	-6.4
Prospective Reserve Margin	25.7%	19.3%	-6.4
Reference Margin Level	11.0%	11.0%	0.0

MRO-Manitoba Hydro Adequacy Data

Demand, Resource, and Reserve Margins	2020–2021 WRA	2021–2022 WRA	2020–2021 vs. 2021–2022 WRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,582	4,497	-1.9%
Demand Response: Available	0	0	-
Net Internal Demand	4,582	4,497	-1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,422	5,438	0.3%
Tier 1 Planned Capacity	180	279	55.0%
Net Firm Capacity Transfers	-270	-446	65.1%
Anticipated Resources	5,226	5,271	0.9%
Existing-Other Capacity	38	46	21.3%
Prospective Resources	5,146	5,318	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	17.2%	3.1
Prospective Reserve Margin	12.3%	18.3%	6.0
Reference Margin Level	12.0%	12.0%	0.0

NPCC-Maritimes Resource Adequacy Data

Demand, Resource, and Reserve Margins	2020–2021 WRA	2021–2022 WRA	2020–2021 vs. 2021–2022 WRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	5,621	5,616	-0.1%
Demand Response: Available	293	317	8.2%
Net Internal Demand	5,328	5,299	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,541	6,584	0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	42	121	188.1%
Anticipated Resources	6,583	6,705	1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	6,583	6,705	1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.6%	26.5%	2.9
Prospective Reserve Margin	23.6%	26.5%	2.9
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,166	20,349	0.9%
Demand Response: Available	579	587	1.3%
Net Internal Demand	19,587	19,762	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,166	32,668	-1.5%
Tier 1 Planned Capacity	0	14	-
Net Firm Capacity Transfers	1,025	1,134	10.7%
Anticipated Resources	34,191	33,816	-1.1%
Existing-Other Capacity	215	184	-14.4%
Prospective Resources	34,422	34,000	-1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	74.6%	71.1%	-3.5
Prospective Reserve Margin	75.7%	72.0%	-3.7
Reference Margin Level	13.6%	15.0%	1.4

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,837	20,940	0.5%
Demand Response: Available	688	132	-80.8%
Net Internal Demand	20,150	20,808	3.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,695	25,403	-4.8%
Tier 1 Planned Capacity	145	63	-56.7%
Net Firm Capacity Transfers	-500	-500	0.0%
Anticipated Resources	26,340	24,966	-5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	26,340	24,966	-5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.7%	20.0%	-10.7
Prospective Reserve Margin	30.7%	20.0%	-10.7
Reference Margin Level	14.3%	12.3%	-2.0

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,130	24,025	-0.4%
Demand Response: Available	839	631	-24.7%
Net Internal Demand	23,292	23,394	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,943	40,239	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	496	1,547	212.0%
Anticipated Resources	41,439	41,786	0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	41,439	41,786	0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	77.9%	78.6%	0.7
Prospective Reserve Margin	77.9%	78.6%	0.7
Reference Margin Level	18.2%	18.2%	0.0

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	38,694	39,386	1.8%
Demand Response: Available	2,592	2,368	-8.6%
Net Internal Demand	36,102	37,017	2.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,695	42,072	0.9%
Tier 1 Planned Capacity	24	27	12.5%
Net Firm Capacity Transfers	-541	-499	-7.8%
Anticipated Resources	41,178	41,600	1.0%
Existing-Other Capacity	0	0	-
Prospective Resources	42,278	42,700	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	12.4%	-1.7
Prospective Reserve Margin	17.1%	15.4%	-1.7
Reference Margin Level	10.1%	10.8%	0.7

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	132,175	132,632	0.3%
Demand Response: Available	8,047	8,466	5.2%
Net Internal Demand	124,128	124,166	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	184,212	179,247	-2.7%
Tier 1 Planned Capacity	0	19	-
Net Firm Capacity Transfers	-687	-2,937	327.5%
Anticipated Resources	183,526	176,329	-3.9%
Existing-Other Capacity	0	0	-
Prospective Resources	183,526	176,329	-3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	47.9%	42.0%	-5.9
Prospective Reserve Margin	47.9%	42.0%	-5.9
Reference Margin Level	16.0%	14.7%	-1.3

SERC-East Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,606	44,175	-3.1%
Demand Response: Available	893	903	1.1%
Net Internal Demand	44,713	43,272	-3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,281	53,933	-0.6%
Tier 1 Planned Capacity	122	0	-100.0%
Net Firm Capacity Transfers	266	562	111.3%
Anticipated Resources	54,670	54,495	-0.3%
Existing-Other Capacity	104	0	-100.0%
Prospective Resources	54,773	54,495	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.3%	25.9%	3.6
Prospective Reserve Margin	22.5%	25.9%	3.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,170	40,320	-2.1%
Demand Response: Available	1,869	1,564	-16.3%
Net Internal Demand	39,301	38,756	-1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,782	51,271	-1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-938	99	-110.5%
Anticipated Resources	50,843	51,370	1.0%
Existing-Other Capacity	2,174	3,135	44.2%
Prospective Resources	53,017	54,505	2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.4%	32.5%	3.1
Prospective Reserve Margin	34.9%	40.6%	5.7
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,625	46,074	3.2%
Demand Response: Available	2,709	1,571	-42.0%
Net Internal Demand	41,916	44,503	6.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	57,259	57,694	0.8%
Tier 1 Planned Capacity	125	1,169	835.2%
Net Firm Capacity Transfers	1,071	1,414	32.0%
Anticipated Resources	58,455	60,277	3.1%
Existing-Other Capacity	508	1,147	125.9%
Prospective Resources	58,963	61,424	4.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.5%	35.4%	-4.1
Prospective Reserve Margin	40.7%	38.0%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,889	46,232	-1.4%
Demand Response: Available	2,157	1,682	-22.0%
Net Internal Demand	44,732	44,550	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,330	61,899	-0.7%
Tier 1 Planned Capacity	2	1,102	733.3%
Net Firm Capacity Transfers	-895	-1,218	36.1%
Anticipated Resources	61,437	61,782	0.6%
Existing-Other Capacity	2,049	2,516	22.8%
Prospective Resources	63,486	64,298	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.3%	38.7%	1.4
Prospective Reserve Margin	41.9%	44.3%	2.4
Reference Margin Level	15.0%	15.0%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,062	41,669	-0.9%
Demand Response: Available	252	211	-16.2%
Net Internal Demand	41,811	41,458	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	66,277	65,197	-1.6%
Tier 1 Planned Capacity	298	0	-100.0%
Net Firm Capacity Transfers	-36	-348	866.4%
Anticipated Resources	66,539	64,850	-2.5%
Existing-Other Capacity	0	0	-
Prospective Resources	66,539	64,820	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	59.1%	56.4%	-2.7
Prospective Reserve Margin	59.1%	56.4%	-2.7
Reference Margin Level	15.3%	16.0%	0.7

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	57,699	62,001	7.5%
Demand Response: Available	2,764	2,598	-6.0%
Net Internal Demand	54,935	59,403	8.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	80,715	81,443	0.9%
Tier 1 Planned Capacity	1,359	2,665	96.1%
Net Firm Capacity Transfers	210	210	0.0%
Anticipated Resources	82,284	84,318	2.5%
Existing-Other Capacity	614	0	-100.0%
Prospective Resources	82,898	84,382	1.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	49.8%	41.9%	-7.9
Prospective Reserve Margin	50.9%	42.1%	-8.8
Reference Margin Level	13.75%	13.75%	0.0

WECC-NWPP-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,248	11,569	-5.5%
Demand Response: Available	0	0	-
Net Internal Demand	12,248	11,569	-5.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,974	12,842	-14.2%
Tier 1 Planned Capacity	0	2,743	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	14,974	15,585	4.1%
Existing-Other Capacity	0	0	-
Prospective Resources	14,974	15,585	4.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.3%	34.7%	12.4
Prospective Reserve Margin	22.3%	34.7%	12.4
Reference Margin Level	12.5%	10.5%	-2.0

WECC-NWPP-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,151	11,213	0.6%
Demand Response: Available	0	0	-
Net Internal Demand	11,151	11,213	0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,321	13,077	-1.8%
Tier 1 Planned Capacity	0	146	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	13,321	13,223	-0.7%
Existing-Other Capacity	0	0	-
Prospective Resources	13,321	13,223	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.5%	17.9%	-1.4
Prospective Reserve Margin	19.5%	17.9%	-1.4
Reference Margin Level	12.5%	10.5%	-2.0

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	39,382	39,779	1.0%
Demand Response: Available	859	829	-3.5%
Net Internal Demand	38,523	38,950	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,018	51,996	4.0%
Tier 1 Planned Capacity	0	2,205	-
Net Firm Capacity Transfers	0	449	-
Anticipated Resources	50,018	54,650	9.3%
Existing-Other Capacity	0	0	-
Prospective Resources	50,018	55,312	10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.8%	40.3%	10.5
Prospective Reserve Margin	29.8%	42.0%	12.2
Reference Margin Level	8.5%	8.3%	-0.2

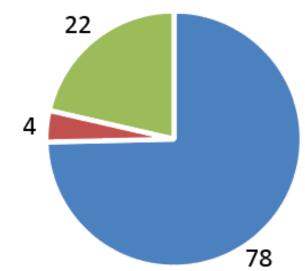
WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	16,355	14,910	-8.8%
Demand Response: Available	62	241	288.2%
Net Internal Demand	16,293	14,669	-10.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	28,522	29,446	3.2%
Tier 1 Planned Capacity	0	381	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	28,522	29,827	4.6%
Existing-Other Capacity	0	0	-
Prospective Resources	28,522	29,836	4.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	75.1%	103.3%	28.2
Prospective Reserve Margin	75.1%	103.4%	28.3
Reference Margin Level	13.0%	14.1%	1.1

WECC-NWPP-US & RMRG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020–2021 WRA**	**2021–2022 WRA**	**2020–2021 vs. 2021–2022 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,899	62,822	10.4%
Demand Response: Available	546	551	1.0%
Net Internal Demand	56,354	62,271	10.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	76,654	74,865	-2.3%
Tier 1 Planned Capacity	0	424	-
Net Firm Capacity Transfers	0	3,877	-
Anticipated Resources	76,654	79,166	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	76,654	79,205	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.0%	27.1%	-8.9
Prospective Reserve Margin	36.0%	27.2%	-8.8
Reference Margin Level	18.0%	14.5%	-3.5

Appendix A: NERC Level 2 Alert Questions and Responses

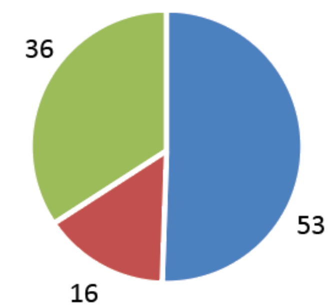
BA Question: Has your organization developed Operating Plans that are closer to real-time (2-3 days ahead), taking into account Balancing Authority Areas and RCs extreme weather capabilities and the ability to provide aid during extreme weather?

USA + Canada	Total	Pct	MRO	NPCC	RF	SERC	TRE	WECC
A) Yes	78	75%	9	7	4	28	2	28
B) No, however we intend to develop such plans	4	4%	-	-	-	1	-	3
C) No, and we do not intend to develop such plans	22	21%	5	-	7	8	-	2



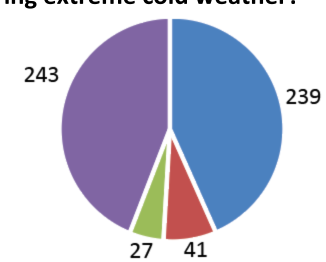
BA Question: Does your organization conduct a seasonal energy and capacity assessment for normal and extreme cold scenarios at least two months prior to the winter season?

USA + Canada	Total	Pct	MRO	NPCC	RF	SERC	TRE	WECC
A) Yes	53	50%	6	5	5	22	2	13
B) No, however we plan to conduct such an assessment	16	15%	1	2	-	5	-	8
C) No, and we have no plans to conduct such an assessment	36	34%	7	-	7	10	-	12



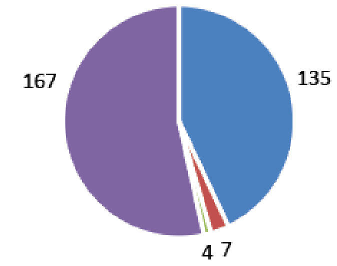
GO Question: If your organization owns fossil-fired units, do you conduct surveys with fuel suppliers for delivery of fuel during extreme cold weather?

USA + Canada	Total	Pct	MRO	NPCC	RF	SERC	TRE	WECC
A) Yes	239	43%	30	42	64	46	25	32
B) No, however, we plan to conduct such surveys	41	7%	6	6	5	5	10	9
C) We will conduct or plan to conduct such surveys for some of the assets we own but not all of them	27	5%	4	4	10	6	1	2
D) No, and we have no plans to conduct any such surveys	243	44%	22	34	45	46	26	70

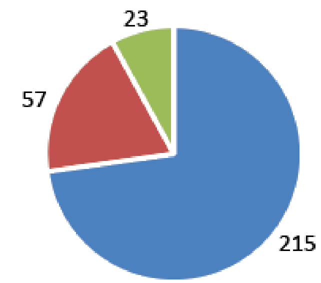


GO Question: Of those GOs who conduct fuel surveys, does your organization conduct dual fuel assessments to ensure resources can switch to the alternate fuel and monitor how much alternate fuel is on site?

USA + Canada	Total	Pct	MRO	NPCC	RF	SERC	TRE	WECC
A) Yes	135	43%	25	27	34	34	4	11
B) No, we own dual fuel units but we do not conduct such assessments	7	2%	1	5	1	-	-	-
C) We own dual fuel units and conduct such assessments for some of the units but not all of them	4	1%	1	-	1	2	-	-
D) We do not own any dual fuel units	167	53%	13	19	45	26	33	31



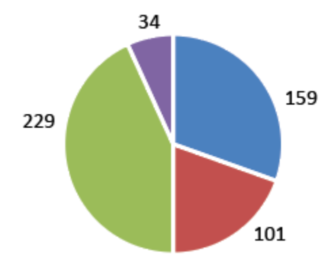
GO Question: Of those GOs who conduct fuel surveys, do (or will) the surveys include an assessment under extreme weather scenarios for supply shrinkage?



USA + Canada	Total	Pct	MRO	NPCC	RF	SERC	TRE	WECC
A) Yes	215	73%	27	34	55	46	22	31
B) No	57	19%	10	10	14	8	10	5
C) We will conduct an assessment of such supply shrinkage for some of the assets we own but not all of them	23	8%	2	6	9	2	1	3

GO Question: Has your organization communicated with natural gas providers (suppliers and pipelines) on emergency plans and implemented actions from the NERC Reliability Guideline: Gas and Electrical Operational Coordination Considerations?

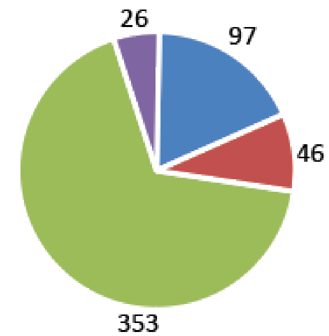
USA + Canada	Total	Pct	MRO	NPCC	RF	SERC	TRE	WECC
A) Yes	159	30%	19	26	37	39	18	20
B) No, however, we plan to connect with them	101	19%	19	12	20	14	17	19
C) No, and we have no plans to connect with them	229	44%	22	38	41	38	24	66
D) We do communicate or plan to communicate on behalf of some of the units we own but not all of them	34	7%	2	6	14	6	2	4



Entities provided an assessment of their generation capacity that will be unavailable due to extreme cold weather conditions. The assessed unavailable capacity of the 197 GOs that indicated they have no plans or partial plans to perform a survey of these factors (C or D) is 6,750 MW: MRO-2,284 MW; NPCC-581 MW; RF-200 MW; SERC-723 MW; Texas RE-330 MW; WECC-2,638 MW.

GO Question: Has your organization coordinated with the appropriate entities to identify applicable natural gas system supply chain facilities' (i.e., facilities used for production, treating, processing, pressurizing, storing or transporting)?

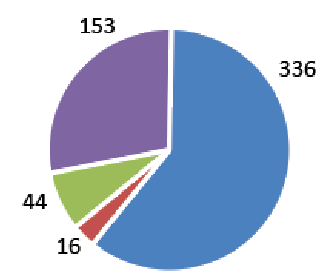
USA + Canada	Total	Pct	MRO	NPCC	RF	SERC	TRE	WECC
A) Yes	97	19%	14	15	13	28	15	12
B) No, however, we plan to coordinate with them	46	9%	6	4	14	9	2	11
C) No, and we have no plans to coordinate with them	353	68%	40	60	76	56	38	83
D) We perform this coordination for some of our natural gas assets but not all of them	26	5%	2	4	9	5	3	3



GO Question: If you own fossil-fired units, has your organization surveyed the unit weatherization and availability for the following factors:

- **Temperatures and other weather conditions that the units can operate through if on-line prior to the extreme conditions (cold, or extreme wind and precipitation)?**
- **Consider pre-seasonal unit startup tests and unit scheduling for infrequently run or off-line resources, or resources that have been off-line for prolonged period of time?**
- **Seasonal emissions/environmental surveys?**
- **Minimum alternate fuel burning procedures?**
- **Water-related vulnerabilities?**

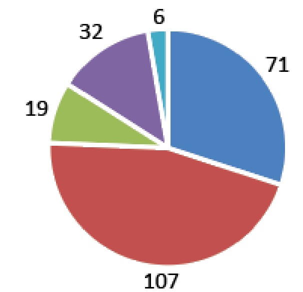
USA + Canada	Total	Pct	MRO	NPCC	RF	SERC	TRE	WECC
A) Yes	336	61%	42	49	89	60	37	59
B) No, however, we plan to survey these factors	16	3%	2	8	2	2	-	2
C) No, and we have no plans to survey these factors	44	8%	3	7	4	5	2	23
D) We have performed, or plan to perform, a partial analysis, surveying some or all of these factors, and/or including some or all of the assets in our system	153	28%	15	22	29	36	23	28



Entities provided an assessment of their generation capacity that will be unavailable due to extreme cold weather conditions. The assessed unavailable capacity of the 197 GOs that indicated they have no plans or partial plans to perform a survey of these factors (C or D) is 23,850 MW: MRO-6,526 MW; NPCC-<50 MW; RF-4,746 MW; SERC-2,595 MW; Texas RE-3,056 MW; WECC-6,877 MW.

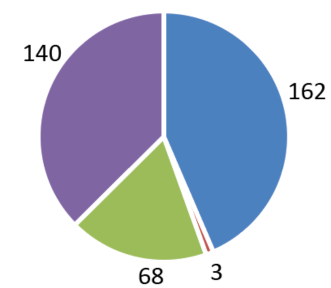
GO Question: If you own solar-powered units, has your organization surveyed the unit weatherization and availability for various following factors specified in the Level 2 Alert?

USA + Canada	Total	Pct	MRO	NPCC	RF	SERC	TRE	WECC
A) Yes, we include all of these factors	71	30%	9	2	5	11	11	33
B) Yes, we include some of these factors	107	46%	7	2	10	32	15	41
C) No, however, we plan to survey these factors	19	8%	7	1	1	1	8	1
D) No, and we have no plans to survey these factors	32	14%	2	-	4	3	2	21
E) We have collected or plan to collect this information for some of the assets that we own but not all of them	6	3%	2	-	1	-	-	3



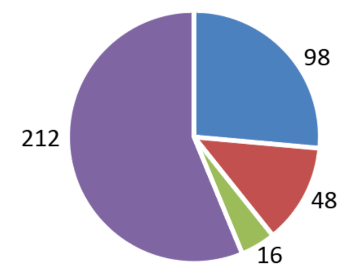
GO Question: If you own wind-powered units, are the units equipped with cold weather packages?

USA + Canada	Total	Pct	MRO	NPCC	RF	SERC	TRE	WECC
A) Yes	162	43%	52	16	32	10	24	28
B) No, however, we plan to equip our units with cold weather packages	3	1%	1	-	-	-	1	1
C) Some of our units are equipped with cold weather packages but not all of them	68	18%	20	4	10	6	17	11
D) No, and we have no plans to equip our units with cold weather packages	140	38%	24	1	7	4	77	27



GO Question: If you own wind-powered units, do you have a procedure for mitigating blade icing?

USA + Canada	Total	Pct	MRO	NPCC	RF	SERC	TRE	WECC
A) Yes	98	26%	24	4	16	7	26	21
B) No, however, we plan to develop such a procedure	48	13%	17	3	6	2	14	6
C) Some of our units have a procedure for mitigating blade icing bu	16	4%	4	2	2	3	2	3
D) No, and we have no plans to develop one	212	57%	52	12	25	9	77	37



Errata

December 2021

- Map of the six REs in the ERO Enterprise updated with correct RF and MRO boundaries (page 2)
- Nuclear generator availability data in Table 2 and Table 3 corrected (page 10)
- Map of the 20 assessment areas updated with clear labels for MISO, SPP, and PJM assessment areas (page 20)
- On-Peak Fuel Mix charts in the Regional Assessments Dashboard updated (pages 21–40)