NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2020–2021 Winter Reliability Assessment

November 2020

Table of Contents

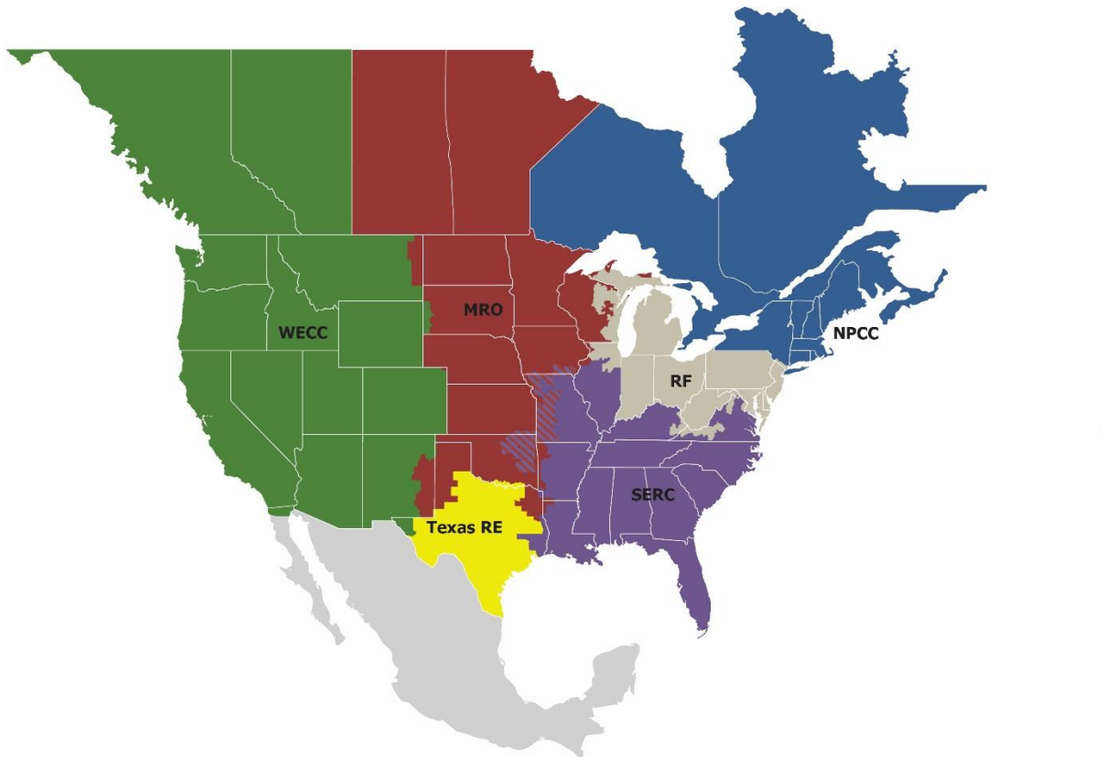
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), 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 and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners/Operators participate in another.



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

About this Assessment

NERC's *2020–2021 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 as well as 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 Regional Entities, and NERC staff. This assessment reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, and regulatory bodies so they are better prepared to take necessary actions to ensure BPS reliability. The assessment also provides an opportunity for the industry to discuss their plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

NERC's annual WRA covers the upcoming three-month (December–February) 2020–2021 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 key 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:

- **Sufficient capacity resources are expected to be in-service for the upcoming winter:** In all areas, the Anticipated Reserve Margin meets or surpasses the Reference Margin Level,[1] indicating that existing and planned resources in these areas are adequate to manage risk of a capacity deficiency under normal conditions (i.e., normal demand forecasts[2]).
- **Fuel supply and energy assurance risk remains a reliability concern in New England and California:** While Anticipated Reserve Margins indicate adequate resources are in service throughout North American, fuel assurance risk remains a reliability concern in some assessment areas. For natural gas, demand is growing as a generator fuel source and for traditional winter space heating needs. However, generating units that lack alternate fuel sources and/or firm contracts for natural gas supply and transportation may not be able to deliver their dispatched energy production profiles.
    - New England generation continues to be limited by the availability of natural gas. While even under abnormally cold conditions that can limit the delivery of natural gas to electric power generators, the operational risk scenarios in this assessment show firm load can still be served. However, under a more severe and prolonged winter event—similar to what was observed in January 2018[3]—limited oil inventories can lead to the eventual loss of generation and firm load shed. ISO-New England continues to enhance processes in support of fuel assurance that it began in 2018. Activities include routine generator fuel surveys and a *21-Day Energy Assessment Forecast and Report* to provide market participants with early indications of potential fuel scarcity conditions and inform fuel procurement decisions.[4] Enhanced coordination with the regional natural gas sector continues as necessary.
    - California and the southwest area in the Western Interconnection rely on natural-gas-fired generation capacity for over 60% of their on-peak demand. However, the area has limited natural gas storage and lacks redundancy in supply infrastructure. As a result, electric generators face risk of fuel supply curtailment or disruption from extreme events that impact natural gas supplies. Examples include natural gas pipeline disruption or freezing temperatures at natural gas production well-heads that reduce the flow of natural gas into the area. Because most on-peak demand is served by natural-gas-fired generation, impacts to fuel supplies can result in energy emergencies on the BPS with a potential for load impacts.[5]
- **Extreme weather continues to pose risk to BPS reliability during the winter season:** Extreme winter weather can challenge system operators and limit the availability of resources (e.g., wind generation blade icing, frozen coal piles, curtailment of natural gas pipelines). Harsh conditions characterized by extreme or prolonged cold temperatures over a large area of North America, such as those experienced during the cold snaps in January 2018 and 2019, create special challenges in maintaining grid reliability in many parts of the North American BPS.[6] Increased demand caused by frigid temperatures, higher generator forced outage rates, and derated output of some generation resources in susceptible areas could create conditions that lead system operators to take emergency operating actions that may result in energy emergencies. NERC's operational risk assessment, which is presented in detail in the **Risk Highlights for Winter 2020–2021** section, identifies BPS resource deficiencies in parts of North America that could occur during extreme winter weather. An operational risk assessment for each assessment area is located in the **Regional Assessment Dashboards**:

[1] The Reference Margin Level is typically based on load, generation, and transmission characteristics for each assessment area. In some cases, the Reference Margin Level is a requirement implemented by the respective state(s), provincial authorities, ISO/RTO, or other regulatory bodies. See **Data Concepts and Assumptions** section.

[2] Electricity demand projections, or load forecasts, are provided by each assessment area. Demand projections are based on normal weather (50/50 distribution) and are provided on a coincident basis; 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.

[3] *ISO-New England 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/

[4] ISO-New England posts the *21-Day Energy Assessment Forecast and Report* on their Operations Reports web page: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results

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

[6] See the FERC and NERC staff report: *January 2018 South Central United States Cold Weather Bulk Electric System Event FERC NERC Report*: https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

- Under studied conditions, grid operators would need to employ operating mitigations or energy emergency alerts (EEAs) to obtain resources necessary to meet extreme peak demands. Potential extreme generation resource outages and peak loads that can accompany extreme winter weather may result in reliability risks in MISO, Maritimes, ERCOT, and WECC-NWPP & RMRG. Furthermore, limitations with the energy infrastructure that supports generator fuel supplies in WECC-CA/MX and NPCC New England could pose risk to BPS reliability during extreme events (see **Figure 1**). More extreme weather than the studied scenarios, though rare, can cause EEAs in other areas.
- Widespread and prolonged periods of cold temperatures can reduce the availability of capacity/energy transfers that can lead to operating risk in areas experiencing internal resource shortfalls. NPCC-Maritimes and NPCC-Québec anticipate that electricity imports would be needed to meet extreme peak demands, as does a portion of SERC-East. Furthermore, any of the assessment areas that are identified in **Figure 1** may need resource assistance in the form of transfers during EEAs. Wide-area winter weather extending over multiple assessment areas carries risk that additional emergency imports may not be available. Reliability risk may also arise when areas reach transmission transfer capacity limitations. Transfer agreements generally include provisions that allow the exporting entity to prioritize serving native load; therefore, even firm transfers may be recalled in some extreme conditions. In January 2018, extreme winter weather in the South Central United States resulted in season-high loads and increased generator outages over a nine-state area. MISO required transfer assistance using neighboring systems to assist with generation shortages in portions of its system. Detailed analysis on transfer affecting operations is shown in the **Transfers in a Wide-Area Cold Snap** section.

- **Impacts from the ongoing pandemic:** The ongoing pandemic is causing increased uncertainty in electricity demand projections and presents cybersecurity and operating risks. No specific threats or degradation to the reliable operation of the BPS are identified for this assessment period. Protecting system and power-plant operators as well as field crews and mitigating heightened cyber risks will continue to be the areas of focus. BPS owners are managing the backlog in generator and transmission maintenance impacted by pandemic in addition to normal winter preparations. Generator maintenance scheduling and outage coordination in the beginning of the winter season must be closely monitored. If maintenance is not able to be performed, forced outages may escalate. Pandemic impacts can affect the accuracy of demand projections in the near term and have the potential to either exacerbate or alleviate planning reserve shortfalls in areas that are below or near Reference Margin levels.
- **Post 2020 hurricane season restoration efforts may continue into the winter season:** The active 2020 hurricane season could have lasting impacts into the winter season. Restoration in Arkansas, Texas, and North Louisiana is complete. Restoration activities continue to focus on the Southwest Louisiana area, primarily in and around the city of Lake Charles.

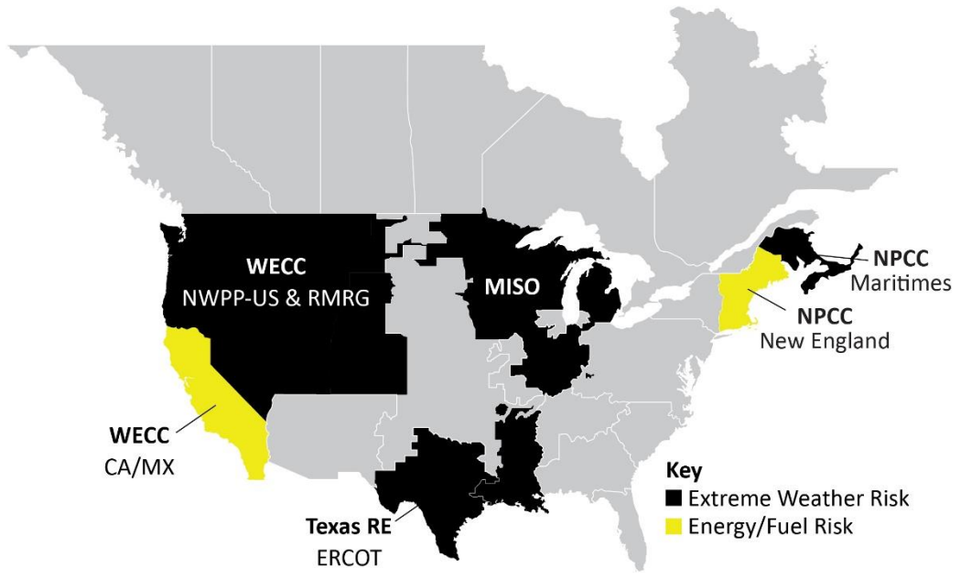


Figure 1: Areas with Reliability Risks during Extreme Weather Events and/or Fuel Supply Disruptions

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.[7] 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 2020–2021 winter as shown in **Figure 2**. 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 occur in early morning hours or other times of darkness in many areas, 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.

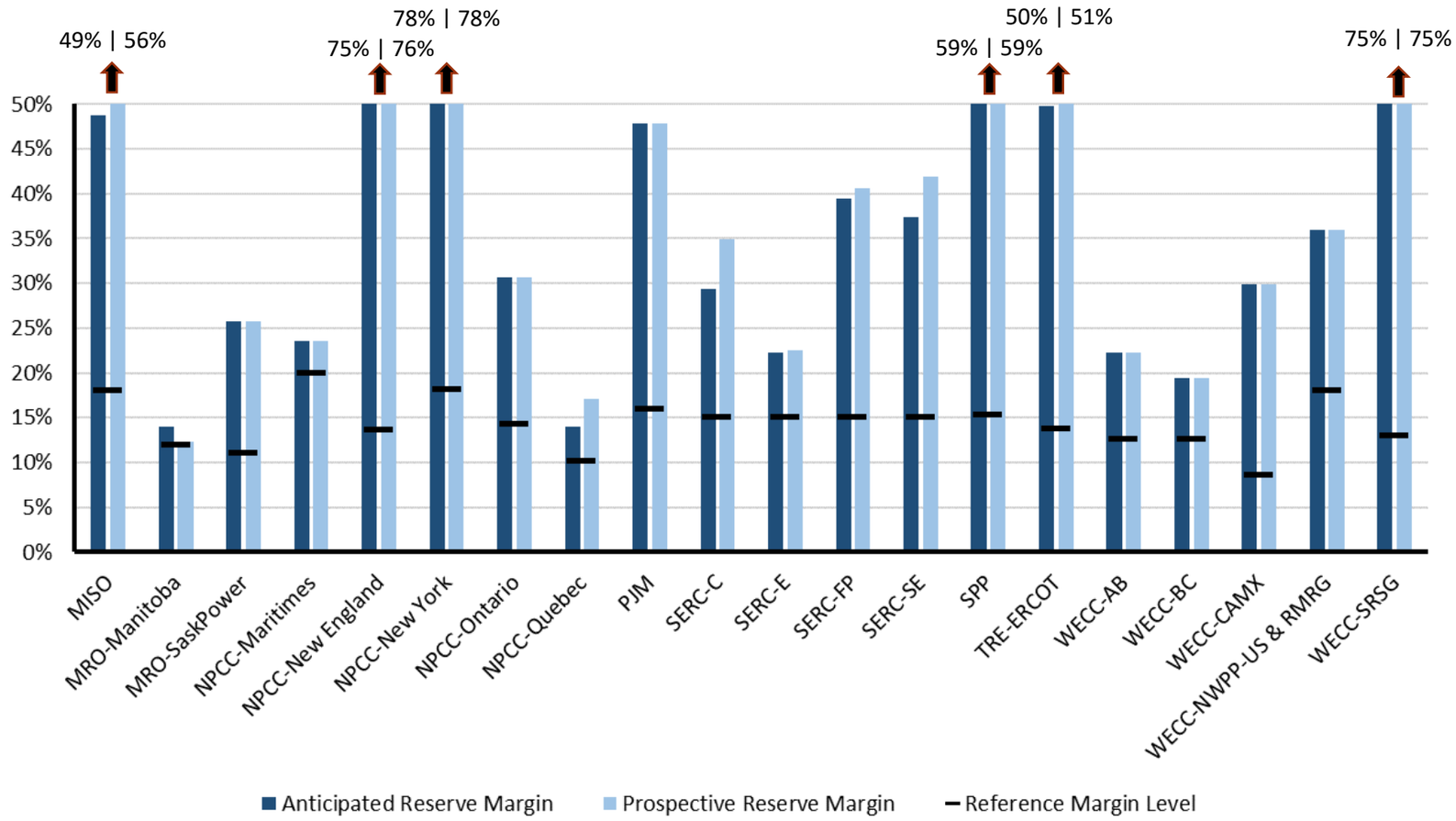


Figure 2: Winter 2020–2021 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[7] 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 3 provides the relative change in the forecast Anticipated Reserve Margins from the 2019–2020 winter to the 2020–2021 winter. A significant decline can indicate potential operational issues that emerge between reporting years. The areas of MRO-Manitoba and SERC-Call had noticeable reductions in Anticipated Reserve Margins between the 2019–2020 winter and the 2020–2021 winter. The lower Anticipated Reserve Margins for MRO-Manitoba and SERC-C result from increased exports on peak for this upcoming winter. No comparison is provided for the assessment area of WECC-NWPP & RMRG as the two areas merged since the *2019-2020 Winter Reliability Assessment*. Additional details are provided in the Data Concepts and Assumptions section.

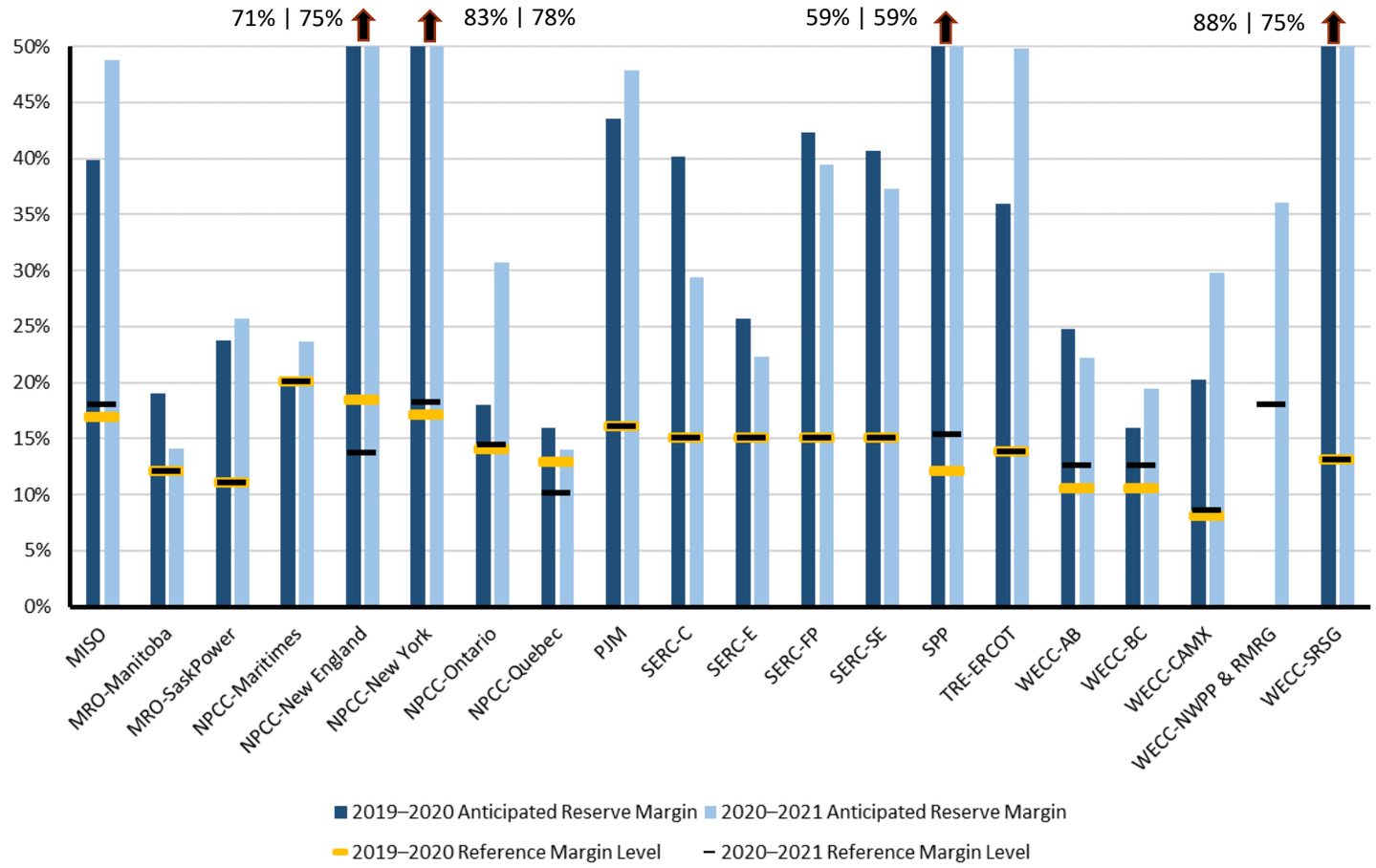


Figure 3: Winter 2019–2020 and Winter 2020–2021 Anticipated Reserve Margins Year-to-Year Change[8]

[8] WECC-NWPP and WECC-RMRG merged in 2020, so an Anticipated Reserve Margin or a Reference Margin Level was not produced for the 2019 assessment year for comparison.

Risk Highlights for Winter 2020–2021

About the Seasonal Risk Assessment

The operational risk analysis shown in Figure 4 provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to anticipated capacity, such as 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 winter reserve margins.

Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The effects from low-probability, extreme events are also factored in through additional resource derates or extreme resource scenarios and extreme winter peak load conditions. Because the seasonal risk scenario shows the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low. An analysis similar to the ISO-NE seasonal risk scenario in Figure 4 can be found for each assessment area in the

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, and 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 4 shows an example seasonal risk assessment for the ISO-New England area that was developed using data from NPCC and ISO-New England. A description of resource and demand variables for Figure 4 is found in Table 1.

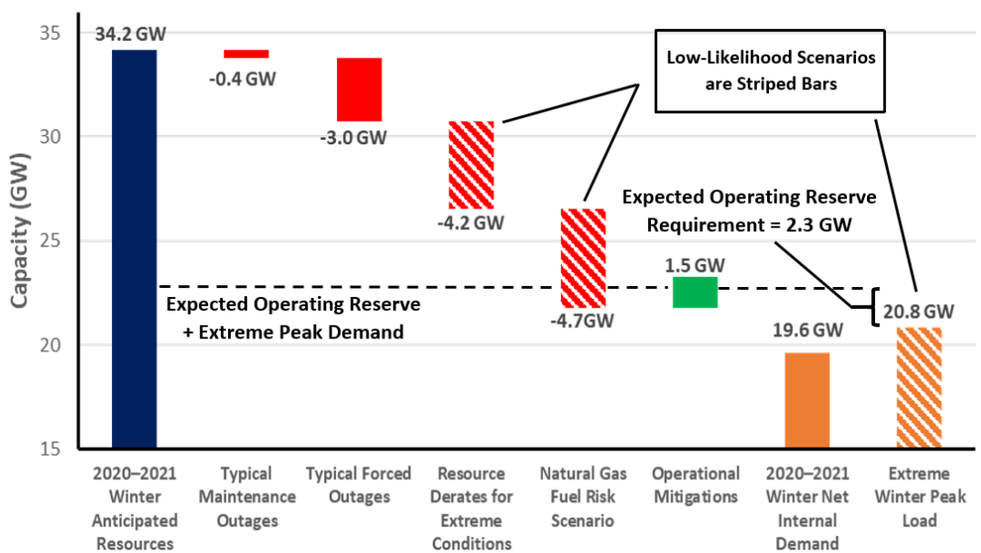


Figure 4: ISO-NE Area Seasonal Risk Assessment at Extreme Peak Demand

The seasonal risk assessment for ISO-New England shows that resources are available to meet extreme conditions; however, energy security challenges remain a concern. 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. However, the seasonal risk assessment may 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.

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.
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.
Resource Derates for Extreme Conditions (Low-likelihood)	A low-likelihood, high forced outage scenario is used to analyze the effect of extreme weather-driven generation outages. The assumed forced outage for this scenario is based on the sum of the unplanned outages plus the natural-gas-fired generation at risk of not having fuel during 90/10 peak load conditions.
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 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 peak hour 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 4 is the maximum.
Operational Mitigations	An estimated combination of load relief 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 Balancing Authority (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).
Demand Scenarios	
2020–2021 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	A seasonal load adjustment is added to the 2020–2021 net internal demand based on a 90/10 statistical extreme load forecast.

Seasonal Risk Assessments for Other Areas

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessment Dashboards** section. The resource adequacy data table and seasonal risk scenario chart in each dashboard provide potential winter peak demand and resource condition information. The table on the right side of the dashboard page presents a standard seasonal assessment and comparison to the previous year's assessment. The seasonal risk scenario chart presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario chart. See the **Data Concepts and Assumptions** for more information about this chart. Potential extreme generation resource outages and peak loads that can accompany extreme winter weather may result in reliability risks in MISO, ERCOT, and WECC-NWPP & RMRG areas as well as the Canadian Maritime provinces. Some parts of the system within the WECC area could also experience resource shortfalls in low-likelihood resource

derate scenarios. Under studied conditions for these areas, grid operators would need to employ operating mitigations or EEAs to obtain resources necessary to meet extreme peak demands. Table 2 describes the various EEA levels and the circumstances for each.

Table 2: 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.

Transfers in a Wide-Area Cold Snap

When extreme weather extends over a wide area, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Some assessment areas expect imports from other areas to be available to meet periods of peak demand and have contracted for firm transfer commitments. A summary of area firm on-peak imports and exports is shown in Table 3. Firm resource transactions, such as these, are accounted for in all assessment area anticipated resources and reserve margins. Areas with net imports show a positive transfer amount, and areas with net exports show a negative transfer amount. Only areas that contained transfers for the previous or upcoming winter seasons are shown in Table 3. NOTE: The Table 3 data is sourced from the data adequacy tables in the Regional Assessment Dashboards.

Table 3: 2019–2020 and 2020–2021 Transfers

Assessment Area	2019–2020 Winter Transfers (MW)	2020–2021 Winter Transfers (MW)	Year-to-Year Change
MISO	-383	1,405	N/A
MRO-Manitoba	-108	-270	149.9%
MRO-SaskPower	25	125	400%
NPCC-Maritimes	-110	42	N/A
NPCC-New England	1,017	1,025	1%
NPCC-New York	678	496	-27%
NPCC-Ontario	-500	-500	0%
NPCC-Quebec	202	-541	N/A
PJM	830	-687	N/A
SERC-C	355	-938	N/A
SERC-E	530	266	-50%

Table 3: 2019–2020 and 2020–2021 Transfers			
Assessment Area	2019–2020 Winter Transfers (MW)	2020–2021 Winter Transfers (MW)	Year-to-Year Change
SERC-FP	1,257	1,071	-15%
SERC-SE	-1,905	-895	-53%
SPP	-378	-36	-90%
TRE-ERCOT	50	210	320%
WECC-NWPP-US and RMRG	700	0	-100%

In the unlikely event that multiple assessment areas are experiencing energy emergencies as could occur in a wide-area cold snap, some transfers may be at risk of not being fulfilled. Transfer agreements may include provisions that allow the exporting entity to prioritize serving native load. Loss of transfers could exacerbate resource shortages that occur from outages and derates. Below are operational risk scenarios showing how a loss of transfers during periods of extreme peak demand and high outage rates could affect the areas of ISO-NE and SERC-E. These areas are selected because capacity transfers can be an important resource contribution toward meeting operating reserves shown in Figure 5 and Figure 6.

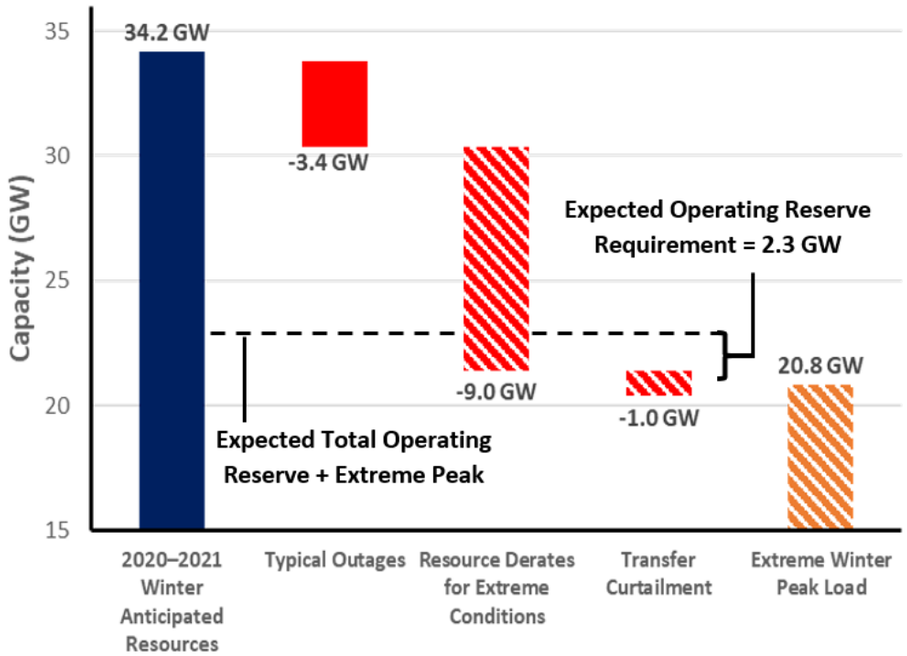


Figure 5: ISO-NE Transfer Curtailment Extreme Scenario

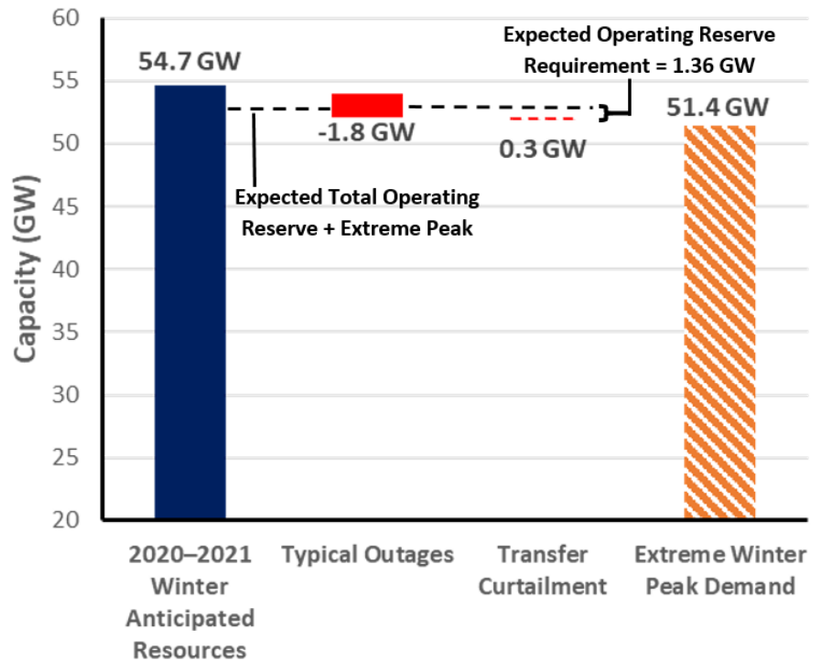
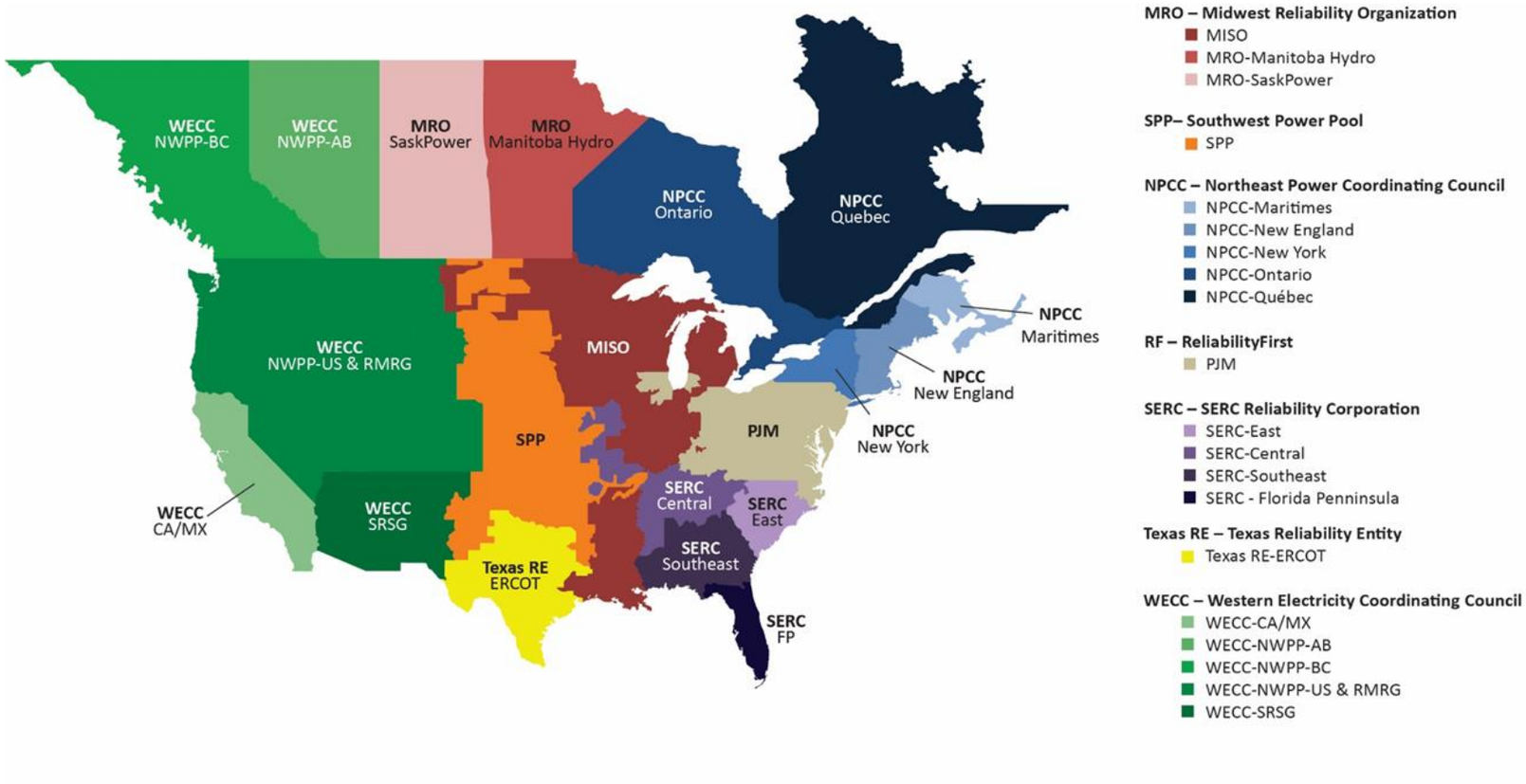


Figure 6: SERC-E Transfer Curtailment Extreme Scenario

Regional Assessment Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the REs on an assessment area basis.

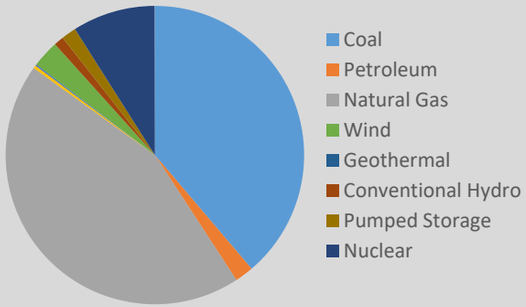


Seasonal risk scenarios for each assessment area are presented in following pages of this section. The resource adequacy data table and seasonal risk scenario chart in each dashboard provide potential winter peak demand and resource condition information. The table on the right side of the dashboard page presents a standard seasonal assessment and comparison to the previous year's assessment. The seasonal risk scenario chart presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario chart; see the **Data Concepts and Assumptions** section for more information about this chart. Fuel mix charts for each assessment area show the on-peak capacity of each resource type. For variable energy resources, such as wind and solar, this may be significantly less than the installed capability.

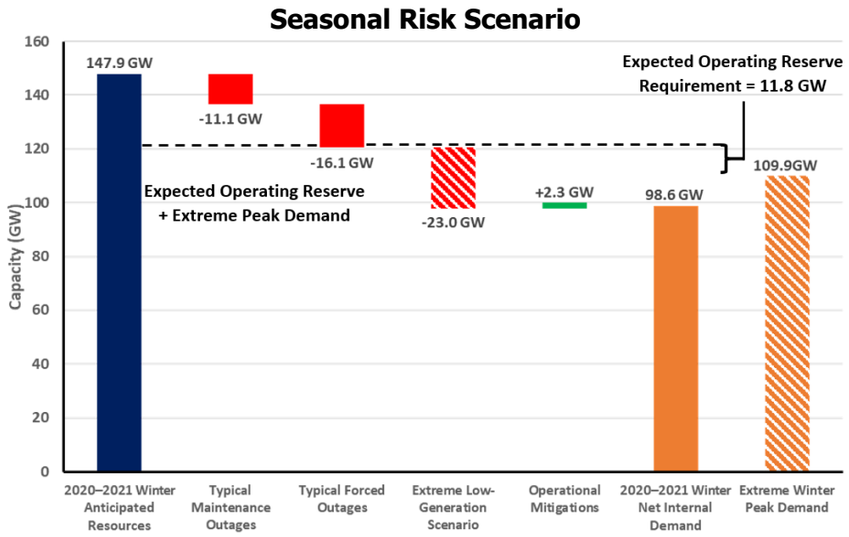
MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering 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 Balancing Authorities and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in 3 NERC Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.



On-Peak Generation Fuel Mix



Risk Scenario Summary

Operating mitigations or EEAs may be needed under extreme peak demand and outage scenarios studied.

Scenario Assumptions

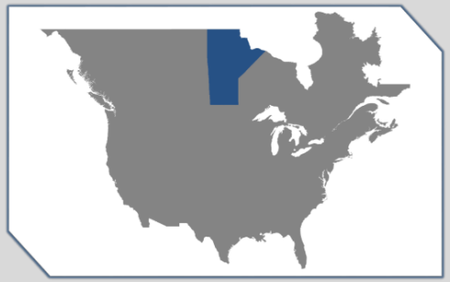
- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Average from highest peak hour over the past five winters
- **Extreme Generation Scenario:** Additional outages corresponding to maximum generation outages observed at highest peak hour in past five years
- **Operational Mitigations:** Derived from required deployable contingency reserves.

MISO Resource Adequacy Data

Demand, Resource, and Reserve Margins	2019–2020 WRA	2020–2021 WRA	2019–2020 vs. 2020–2021 WRA
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	103,841	103,167	-0.6%
Demand Response: Available	3,822	4,536	18.7%
Net Internal Demand	100,019	98,631	-1.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	139,555	144,736	3.7%
Tier 1 Planned Capacity	778	574	-26.2%
Net Firm Capacity Transfers	-383	1,405	N/A
Anticipated Resources	139,951	146,715	4.8%
Existing-Other Capacity	535	6,390	1,094.3%
Prospective Resources	140,486	153,557	9.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.9%	48.8%	8.9
Prospective Reserve Margin	40.5%	55.7%	15.2
Reference Margin Level	16.8%	18.0%	1.2

Highlights

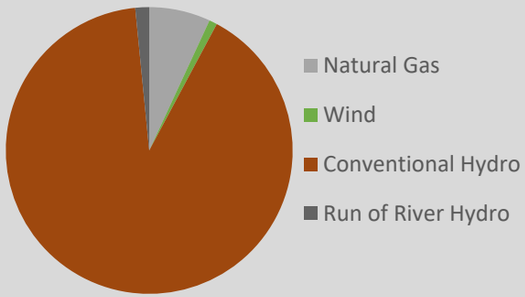
- MISO does not anticipate resource availability issues for the upcoming 2020–2021 winter season. Based on prior winter readiness and fuel deliverability surveys, appropriate measures have been taken, making readying units for potential severe winter weather, and fuel deliverability is robust.
- Generator maintenance outages that were deferred from spring of this year due to the pandemic look to be on track for completion in fall. Extreme warm fall weather may impact scheduled maintenance outages, but there is no indication that these will be pushed into the peak of the winter season.



MRO-Manitoba Hydro

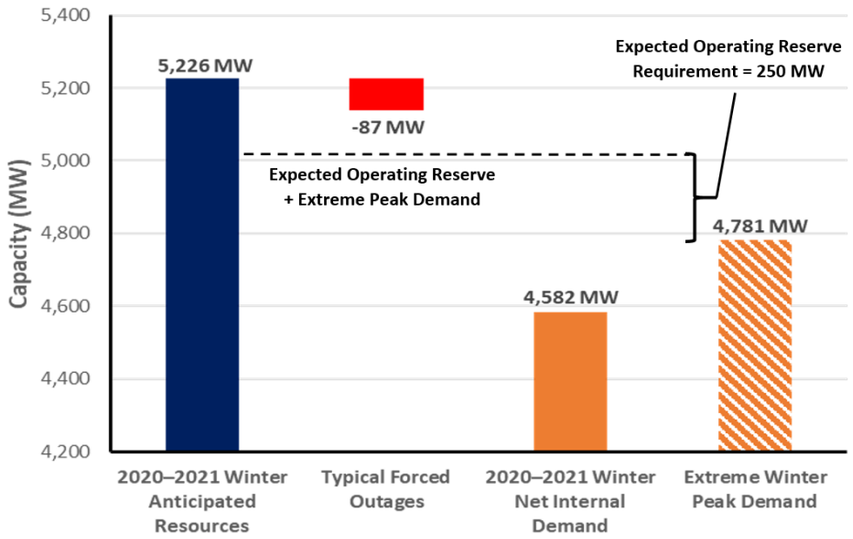
Manitoba Hydro is a provincial crown corporation that provides electricity to about 580,000 customers throughout Manitoba and natural gas service to about 282,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million in an area of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

Seasonal Risk Scenario



MRO-Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2019–2020 WRA**	**2020–2021 WRA**	**2019–2020 vs. 2020–2021 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,505	4,582	1.7%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,505	4,582	1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,469	5,422	-0.9%
Tier 1 Planned Capacity	0	180	0.0%
Net Firm Capacity Transfers	-108	-270	149.9%
Anticipated Resources	5,361	5,226	-2.5%
Existing-Other Capacity	53	38	-28.3%
Prospective Resources	5,414	5,146	-4.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.0%	14.1%	-4.9
Prospective Reserve Margin	20.2%	12.3%	-7.9
Reference Margin Level	12.0%	12.0%	0.0

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

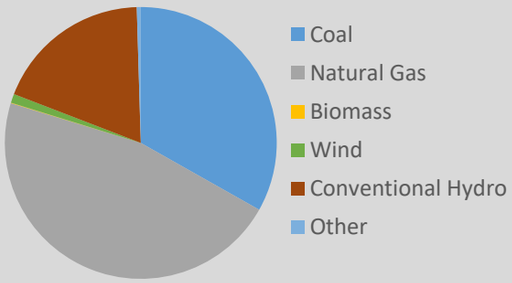
- **Extreme Peak Demand:** Exceeded only 1 hour in 10 years, considering historical hourly weather and load analysis and internal demand resources
- **Maintenance Outages:** Removal of the largest hydro unit
- **Forced Outages:** Based on historical operating experience

Highlights

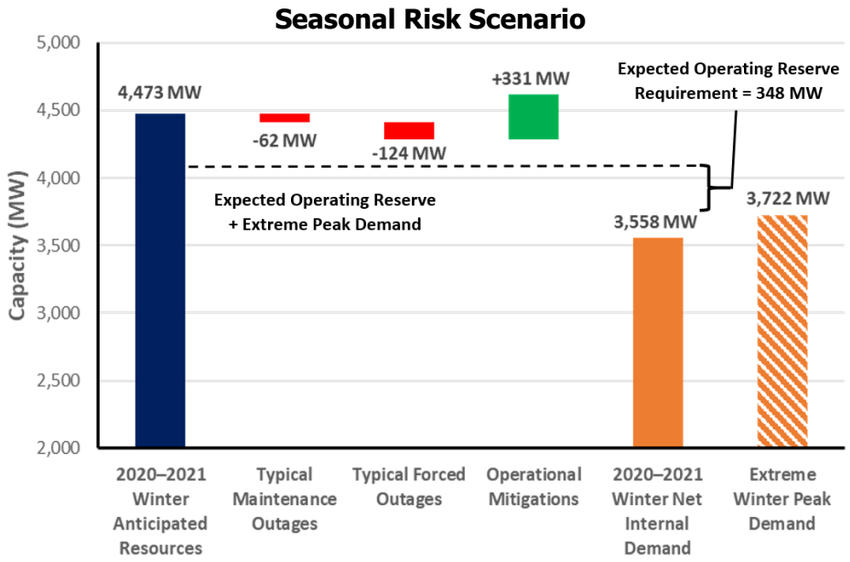
- The winter Anticipated Reserve Margin does not fall below the Reference Margin Level of 12%.
- The effect of the pandemic on the winter peak demand cannot be reliably assessed. Using the load forecast that was prepared prior the pandemic is considered a reasonable, conservative assumption.
- Two of the seven Keeyask hydro station generating units (90 MW per unit) are expected to be operational by December. Work continues to proceed as scheduled.
- The status of the 126 MW winter capacity Selkirk natural gas generating station will be changed from an unconfirmed retirement to a confirmed retirement once the Keeyask units come on-line.
- The newly operational Manitoba–Minnesota 500 kV transmission line provides additional reliability for the Manitoba Hydro system through increased firm import capacity.

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 people. 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 and its interconnections.



On-Peak Generation Fuel Mix



MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2019–2020 WRA**	**2020–2021 WRA**	**2019–2020 vs. 2020–2021 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,803	3,618	-4.9%
Demand Response: Available	85	60	-29.4%
Net Internal Demand	3,718	3,558	-4.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,222	4,348	3.0%
Tier 1 Planned Capacity	353	0	0.0%
Net Firm Capacity Transfers	25	125	400.0%
Anticipated Resources	4,600	4,473	-2.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	4,600	4,473	-2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.7%	25.7%	2.0
Prospective Reserve Margin	23.7%	25.7%	2.0
Reference Margin Level	11.0%	11.0%	0.0

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

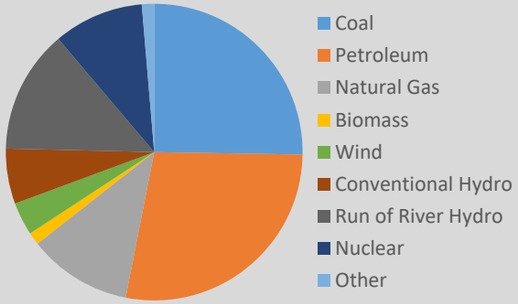
- **Extreme Peak Load:** Peak demand with lighting and all large consumer loads
- **Maintenance Outages:** Estimated based on the difference between average maintenance outages for past three winters and average of estimation for outages for upcoming 2020–2021 winter
- **Forced Outages:** Estimated using SaskPower forced outage model
- **Extreme Derates:** None applied; all derates are included in winter anticipated capacity
- **Operational Mitigations:** Estimated average based on import capability

Highlights

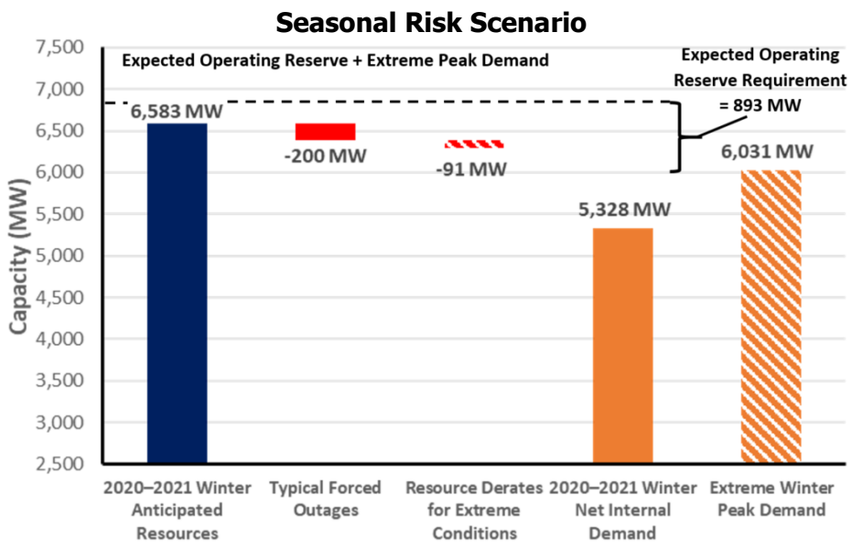
- Saskatchewan experiences peak load in winter as a result of extreme cold weather.
- SaskPower conducts an annual winter joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of an operating reserve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

NPCC-Maritimes

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



On-Peak Generation Fuel Mix



NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2019–2020 WRA**	**2020–2021 WRA**	**2019–2020 vs. 2020–2021 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	5,528	5,621	1.7%
Demand Response: Available	243	293	20.6%
Net Internal Demand	5,285	5,328	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,663	6,541	-1.8%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-110	42	N/A
Anticipated Resources	6,553	6,583	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,553	6,583	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.5%	23.6%	3.1
Prospective Reserve Margin	20.5%	23.6%	3.1
Reference Margin Level	20.0%	20.0%	0.0

Risk Scenario Summary

Operating mitigations or EEAs may be needed in an extreme peak demand scenario.

Scenario Assumptions

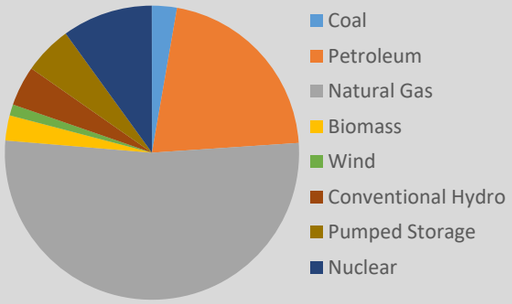
- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** Based on ambient temperature thermal unit reduced capacity and extreme case involving total loss of wind capacity

Highlights

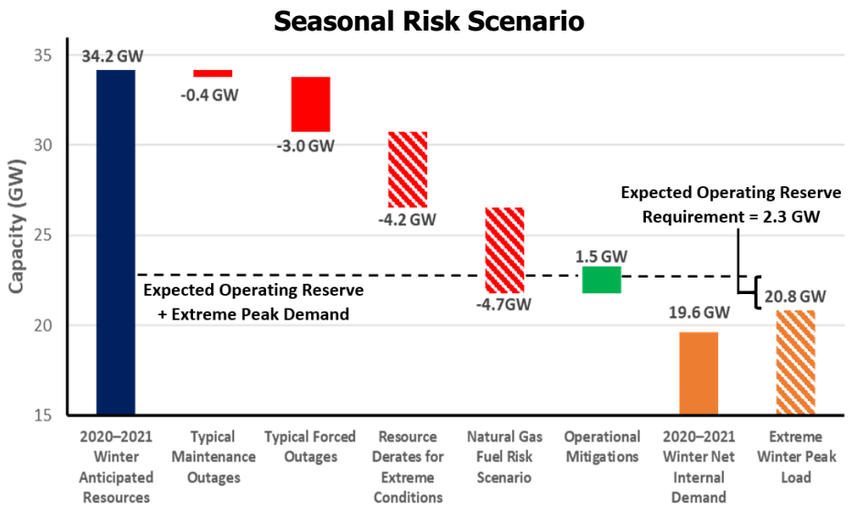
- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for winter.
- The Maritimes 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 pandemic on load patterns, energy usage, and peak demand will continue to be evaluated as the pandemic evolves.

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 bulk power system (BPS). The New England BPS serves approximately 14.5 million customers over 68,000 square miles.



On-Peak Generation Fuel Mix



NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2019–2020 WRA**	**2020–2021 WRA**	**2019–2020 vs. 2020–2021 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,476	20,166	-1.5%
Demand Response: Available	497	579	16.7%
Net Internal Demand	19,979	19,587	-2.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,120	33,166	0.1%
Tier 1 Planned Capacity	12	0	-100.0%
Net Firm Capacity Transfers	1,017	1,025	0.7%
Anticipated Resources	34,149	34,191	0.1%
Existing-Other Capacity	189	215	13.8%
Prospective Resources	34,338	34,422	0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	70.9%	74.6%	3.7
Prospective Reserve Margin	71.9%	75.7%	3.8
Reference Margin Level	18.4%	13.6%	-4.8

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

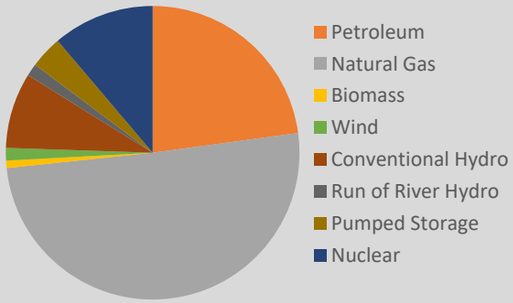
- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Based on weekly averages
- **Extreme Derates:** A low-likelihood, high forced outage scenario used to analyze the effect of extreme weather-driven generation outages
- **Extreme Natural Gas Fuel Risk Scenario:** ISO-NE calculates the amount of generation at risk due to lack of natural gas during cold weather. No natural gas generation at risk above 30°F and a reduction curve for temperatures below 30°F
- **Operating Mitigations:** Based on ISO-NE operating procedures

Highlights

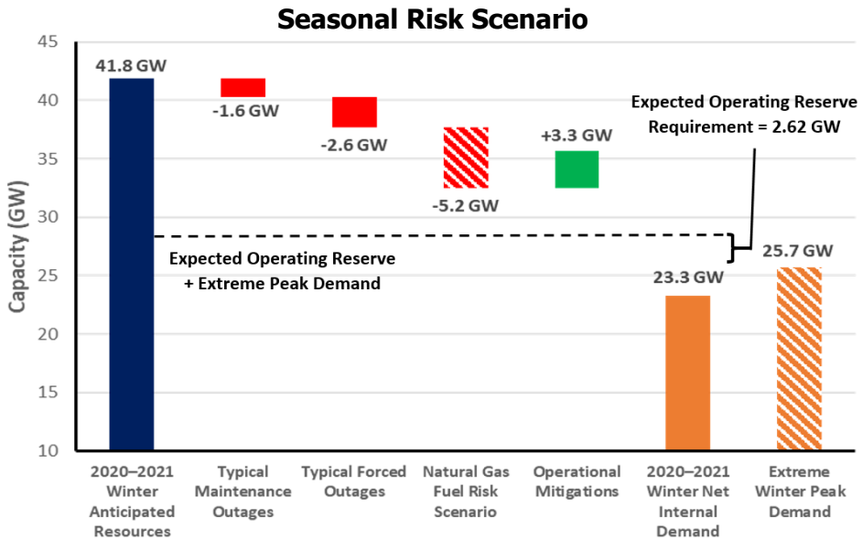
- While ISO New England (ISO-NE) expects to meet its regional resource adequacy requirements during the 2020–2021 winter, a standing concern is whether there will be sufficient electrical energy available to satisfy electricity demand while satisfying operating reserves during an extended cold spell given the existing resource mix and seasonally-constrained, fuel delivery infrastructure.
- ISO-NE continues to stay in contact with system operators in other parts of North America and the world to share pandemic operating experience and hear how it might apply in New England.
- ISO-NE is producing a weekly analysis of the impact the response to the pandemic is having on system demand; it is posted every Tuesday on its external web site. ISO-NE first observed an impact on system demand during the third week of March 2020 when a regional response to the pandemic began. Overall, loads are trending lower than normally would be expected.
- ISO-NE expects to have sufficient resources to meet the 2020–2021 extreme winter peak demand forecast of 20,806 MW for the weeks beginning January 3, January 10, and January 17, 2021.

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 Balancing Authority within the state of New York. The BPS encompasses approximately 11,000 miles of transmission lines, 760 power generation units, and serves 19.5 million customers. New York experienced its all-time peak demand of 33,956 MW in Summer 2013. The NERC 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 2020–2021 IRM at 18.2%."



On-Peak Generation Fuel Mix



NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2019–2020 WRA**	**2020–2021 WRA**	**2019–2020 vs. 2020–2021 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,123	24,130	0.0%
Demand Response: Available	853	839	-1.7%
Net Internal Demand	23,270	23,292	0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,815	40,943	-2.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	678	496	-26.9%
Anticipated Resources	42,493	41,439	-2.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,493	41,439	-2.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	82.6%	77.9%	-4.7
Prospective Reserve Margin	82.6%	77.9%	-4.7
Reference Margin Level	17.0%	18.2%	1.2

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

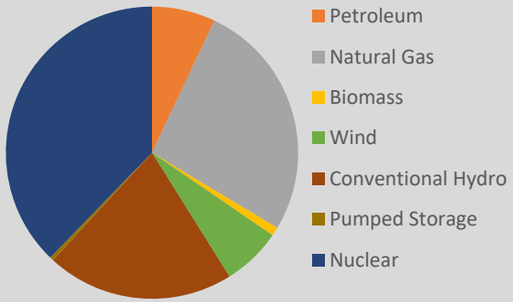
- **Extreme Peak Demand:** 90/10 load forecast with demand response adjustments
- **Maintenance Outages:** based on scheduled maintenance
- **Forced Outages:** based on 5-year averages from the Generator Availability Data System
- **Natural Gas Fuel Risk Scenario:** Extreme scenario assumes all nonfirm supply is unavailable in a period of extended cold weather
- **Operational Mitigation:** 3.3 GW of effects from emergency operating procedure

Highlights

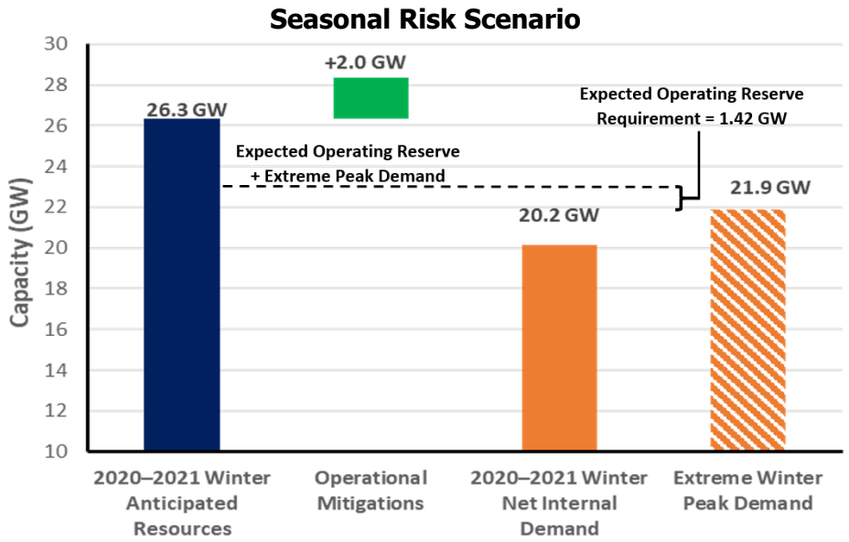
- New York is a summer-peaking area and no emerging reliability issues are anticipated during the 2020–2021 winter assessment period. Surplus capacity margins above the NYISO's operating reserve requirements are projected.

NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority 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 Generation Fuel Mix



NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2019–2020 WRA**	**2020–2021 WRA**	**2019–2020 vs. 2020–2021 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,115	20,837	-1.3%
Demand Response: Available	924	688	-25.6%
Net Internal Demand	20,191	20,150	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	24,298	26,695	9.9%
Tier 1 Planned Capacity	0	145	0.0%
Net Firm Capacity Transfers	-500	-500	0.0%
Anticipated Resources	23,798	26,340	10.7%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	23,798	26,340	10.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.9%	30.7%	12.8
Prospective Reserve Margin	17.9%	30.7%	12.8
Reference Margin Level	14.4%	14.3%	-0.1

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Determined from the most severe historical weather
- **Outages:** Accounted for in anticipated resources. No additional outages due to extreme conditions anticipated.
- **Extreme Derates:** None applied based on operating experience
- **Operational Mitigation:** 2,000 MW imports assessed as available from neighbors

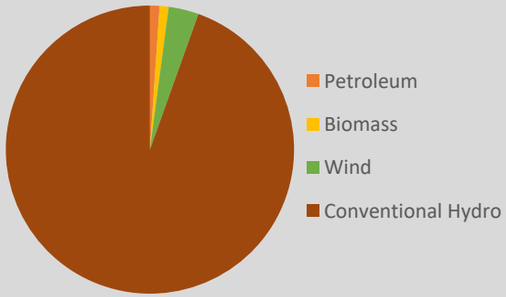
Highlights

- IESO anticipates that it will maintain reliability on its system through Winter 2020–2021.
- 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.
- Imports and exports between New York and Ontario continue to be impacted due to an ongoing interconnection equipment outage at St. Lawrence TS. This has required enhanced coordination with affected parties and more focused management of St. Lawrence area resources in real-time. Careful coordination of transmission and generation outages will continue to be required in the area.

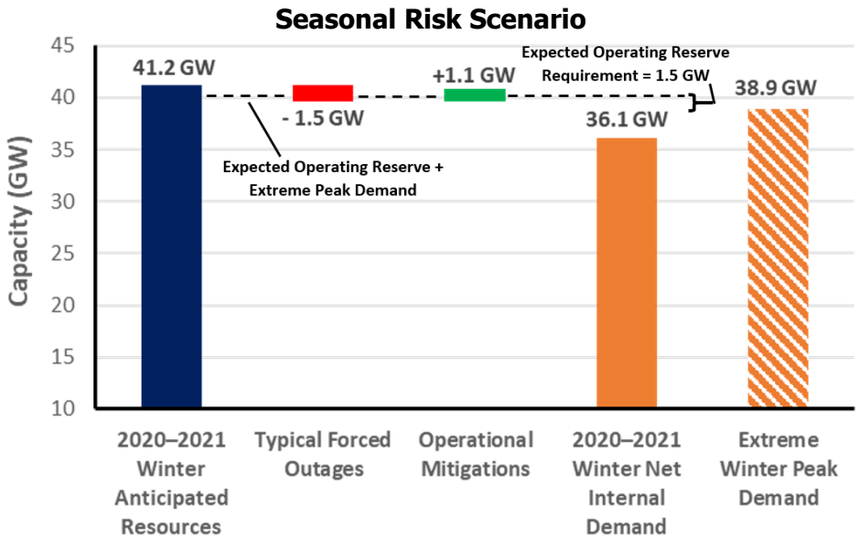
NPCC-Québec

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 4 NERC Interconnections in North America; with 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 Generation Fuel Mix



Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** based on 50/50 load forecast with two standard deviations
- **Forced Outages:** Hydro resources operating in extreme conditions without increased outage rates
- **Operational Mitigations:** 1,100 MW of non-firm imports anticipated to be available in short-term capacity purchases

NPCC- Québec Resource Adequacy Data

Demand, Resource, and Reserve Margins	2019–2020 WRA	2020–2021 WRA	2019–2020 vs. 2020–2021 WRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	38,665	38,694	0.1%
Demand Response: Available	2,284	2,592	13.5%
Net Internal Demand	36,382	36,102	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,917	41,695	-0.5%
Tier 1 Planned Capacity	0	24	0.0%
Net Firm Capacity Transfers	202	-541	N/A
Anticipated Resources	42,119	41,178	-2.2%
Existing-Other Capacity	1,100	0	0.0%
Prospective Resources	43,219	42,278	-2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.8%	14.1%	-1.7
Prospective Reserve Margin	18.8%	17.1%	-1.7
Reference Margin Level	12.8%	10.1%	-2.7

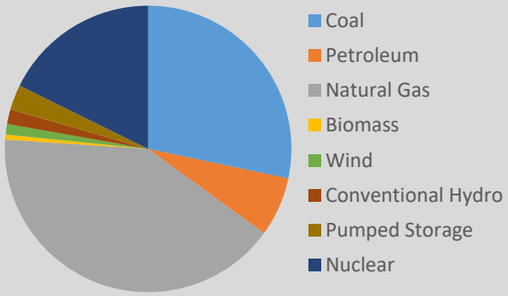
Highlights

- 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 2020–2021 winter.
- No changes have been made to the assessment area's winter preparedness programs.

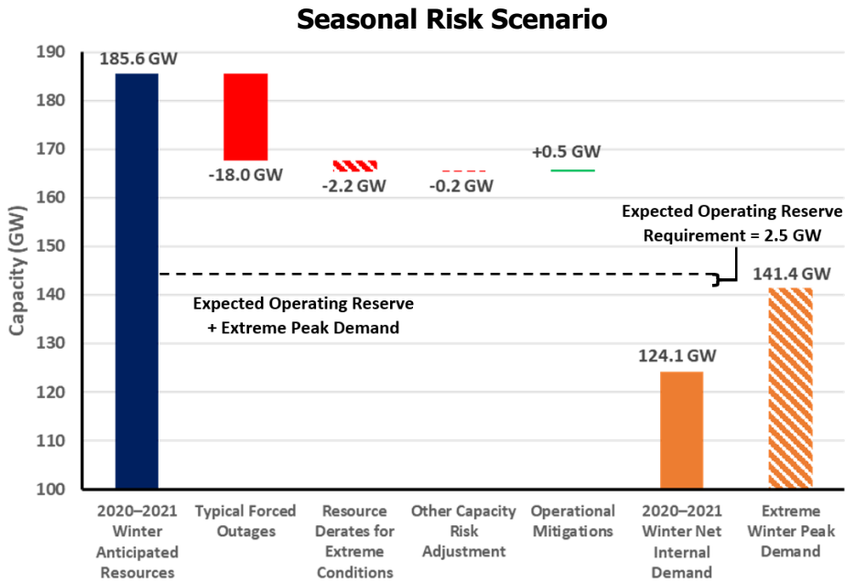
PJM

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 people 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.



On-Peak Generation Fuel Mix



Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages and Derates:** Estimated from analysis of previous winter peak periods

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2019–2020 WRA**	**2020–2021 WRA**	**2019–2020 vs. 2020–2021 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	131,148	132,175	0.8%
Demand Response: Available	965	8,047	733.9%
Net Internal Demand	130,183	124,128	-4.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	186,070	184,212	-1.0%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	830	-687	N/A
Anticipated Resources	186,899	183,526	-1.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	186,899	183,526	-1.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	43.6%	47.9%	4.3
Prospective Reserve Margin	43.6%	47.9%	4.3
Reference Margin Level	16.0%	16.0%	0.0

Highlights

- PJM is expected to serve load and meet its installed reserve requirement through the 2020–2021 winter peak period.
- PJM's Capacity Performance program continues to incent excellent performance of generation and demand-side resources.

SERC

On April 30, 2019, the Federal Energy Regulatory Commission issued an order formally approving the transfer of all registered entities in the Florida Reliability Coordinating Council (FRCC) Regional Entity to SERC by July 1, 2019. The integration of FRCC entities resulted in an additional SERC area and SERC assessment area for inclusion in NERC's reliability assessments.

SERC is a summer-peaking assessment area that covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC is divided into 4 assessment areas: SERC- E, SERC-N, SERC-SE, and SERC-FL Peninsula. The SERC Regional Entity includes 36 Balancing Authorities, 21 Planning Authorities, and 4 Reliability Coordinators.

SERC Resource Adequacy Data

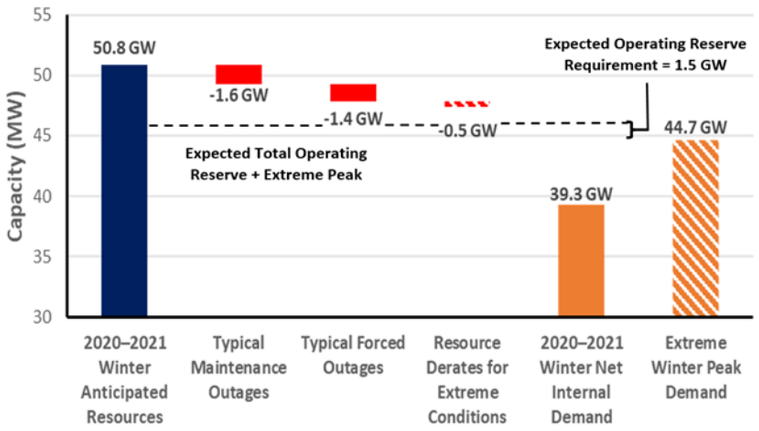
Demand, Resource, and Reserve Margins	SERC-C	SERC-E	SERC-FP	SERC-SE	2019–2020 WRA SERC Total	2020–2021 WRA SERC Total	2019–2020 vs. 2020–2021 WRA
Demand Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,170	45,606	44,625	46,889	176,066	178,290	1.3%
Demand Response: Available	1,869	893	2,709	2,157	8,141	7,628	-6.3%
Net Internal Demand	39,301	44,713	41,916	44,732	167,925	170,662	1.6%
Resource Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,782	54,281	57,259	62,330	227,325	225,653	-0.7%
Tier 1 Planned Capacity	0	122	125	2	2,516	249	-90.1%
Net Firm Capacity Transfers	-938	266	1,071	-895	237	-496	N/A
Anticipated Resources	50,843	54,670	58,455	61,437	230,078	225,405	-2.0%
Existing-Other Capacity	2,174	104	508	2,049	4,361	4,834	10.8%
Prospective Resources	53,017	54,773	58,963	63,486	234,439	230,239	-1.8%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	29.4%	22.3%	39.5%	37.3%	37.0%	32.1%	4.9
Prospective Reserve Margin	34.9%	22.5%	40.7%	41.9%	39.6%	34.9%	4.7
Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	0.0

Highlights

- SERC entities have not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities in SERC reported they have an extensive weatherization process; this includes developed procedures specific to freezing events.
- A *force majeure* was declared on a pipeline in Kentucky affecting natural gas supplied into SERC-Central assessment area. However, firm delivery supply contracts are in place for the potentially impacted power-plants.
- SERC-East states some entities have identified several significant generator outages are possible for the early winter period. The entities will rely on import capabilities to meet the expected winter peak load, should outages occur.

SERC-Central

Seasonal Risk Scenario

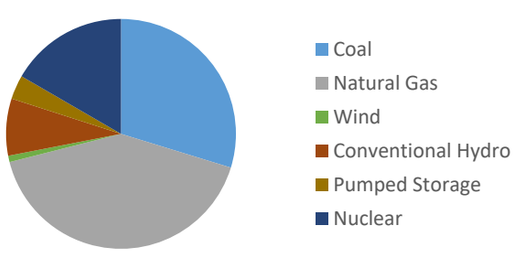


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

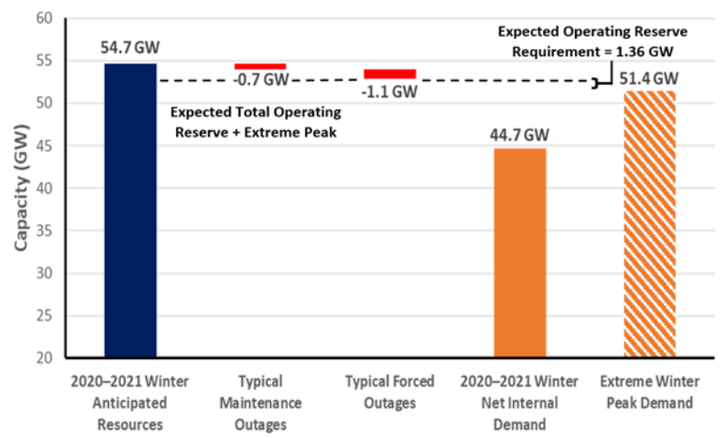
- **Extreme Peak Load:** Determined by SERC to equal or exceed 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by SERC to equal or exceed 90/10 statistical level



On-Peak Generation Fuel Mix

SERC-East

Seasonal Risk Scenario

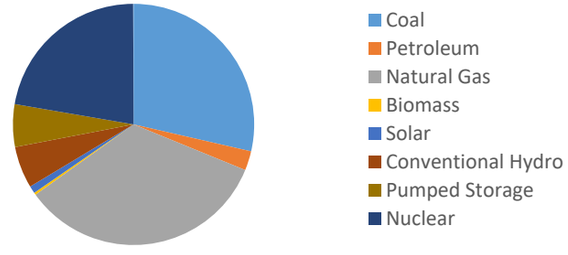


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

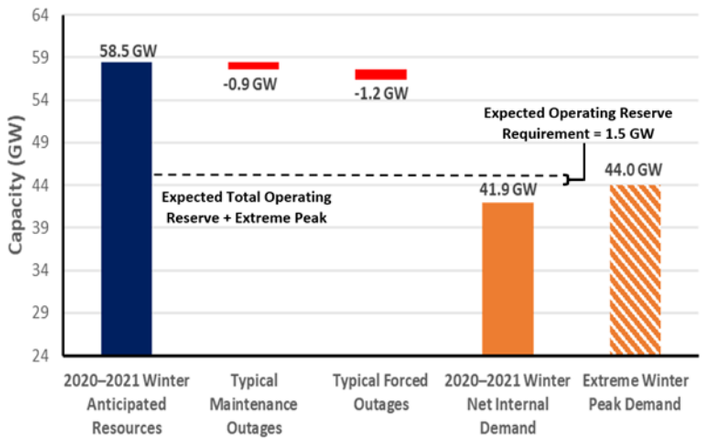
- **Extreme Peak Load:** Determined by SERC to equal or exceed 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by SERC to equal or exceed 90/10 statistical level



On-Peak Generation Fuel Mix

SERC-Florida Peninsula

Seasonal Risk Scenario

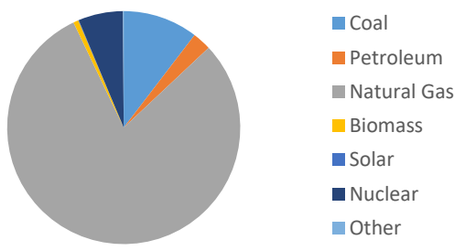


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

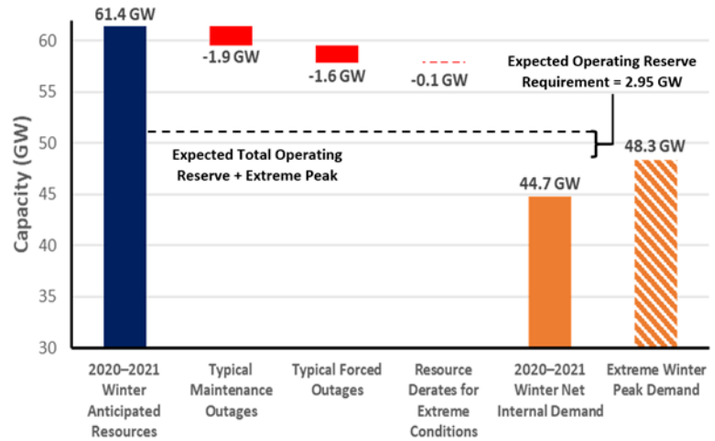
- **Extreme Peak Load:** Determined by SERC to equal or exceed 90/10 statistical level
- **Outages:** Historical average MW during winter peaks
- **Extreme Derates:** Determined by SERC to equal or exceed 90/10 statistical level



On-Peak Generation Fuel Mix

SERC-South East

Seasonal Risk Scenario

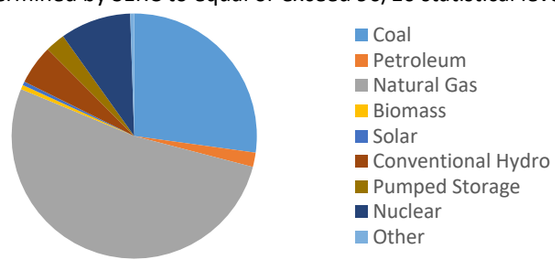


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 Forecast
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by SERC to equal or exceed 90/10 statistical level

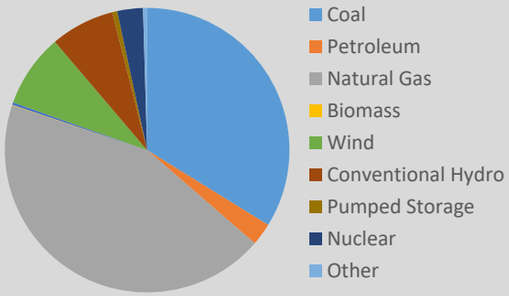


On-Peak Generation Fuel Mix

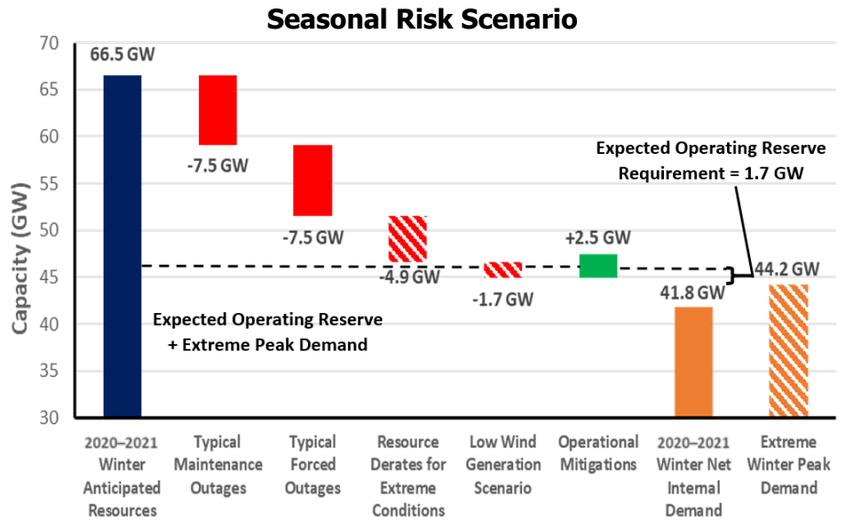
SPP

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 Regional Entity, and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.



On-Peak Generation Fuel Mix



SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2019–2020 WRA**	**2020–2021 WRA**	**2019–2020 vs. 2020–2021 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,399	42,062	-0.8%
Demand Response: Available	223	252	12.6%
Net Internal Demand	42,176	41,811	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,395	66,277	-1.7%
Tier 1 Planned Capacity	0	298	0.0%
Net Firm Capacity Transfers	-378	-36	-90.5%
Anticipated Resources	67,018	66,539	-0.7%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,972	66,539	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	59%	59.1%	0.1
Prospective Reserve Margin	58.8%	59.1%	0.3
Reference Margin Level	12.0%	15.3%	3.3

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data
- **Extreme Cold Wind Gen Outage:** 1.7 GW of wind potentially off-line when temperatures fall below their cold weather performance packages
- **Operational Mitigations:** Additional capacity from committed generation in SPP area to mitigate energy emergencies

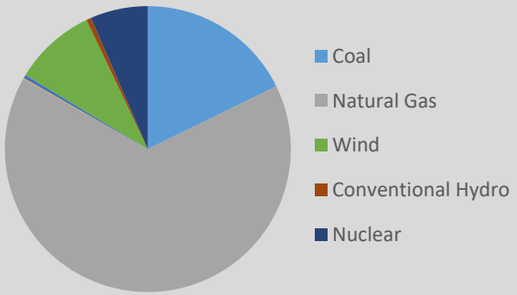
Highlights

- SPP's planning reserves are adequate for the upcoming winter season.
- SPP does not anticipate any emerging reliability issues that impact the area for the 2020–2021 winter season.
- SPP continues to work with neighboring area to address potential electric 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 meet real time reliability needs.
- SPP held its winter preparedness workshop on September 29, 2020.

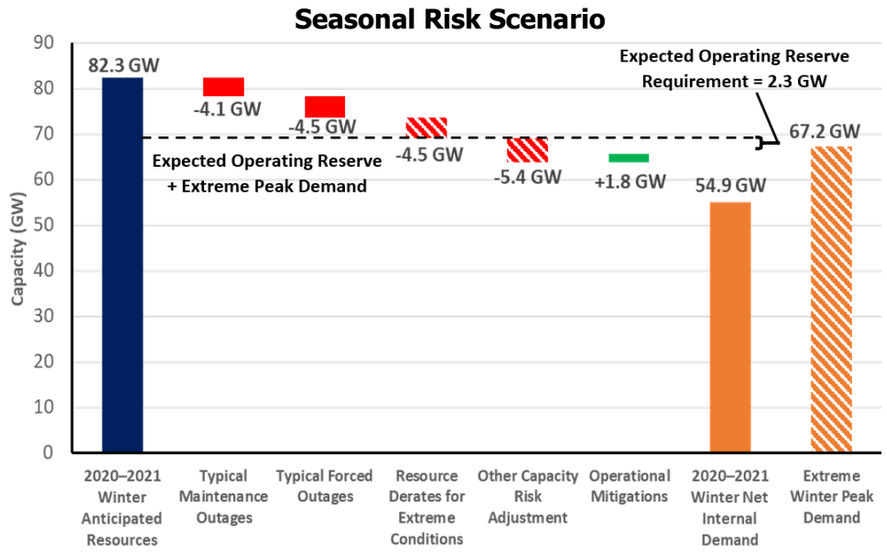
Texas RE-ERCOT

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 Balancing Authority. 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 Regional Entity that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has 650 generation units, and serves more than 25 million customers. Texas RE is responsible for the regional RE functions described in the *Energy Policy Act of 2005* for the ERCOT Regional Entity.



On-Peak Generation Fuel Mix



Risk Scenario Summary

Operating mitigations and EEAs may be needed under extreme demand and extreme resource derated conditions studied.

Scenario Assumptions

- **Extreme Peak Load:** Based on 2011 historic winter peak load
- **Typical Outages:** A capacity derate for thermal resources based on historical averages (Wind, solar, and hydro outages are accounted for in capacity contribution percentages.)
- **Derates for Extreme Conditions:** The expected amount of natural-gas-fired generator derates/outages due to natural gas curtailment at the time of an extreme peak load
- **Other Capacity Risk Adjustment:** Low wind output based on the fifth percentile of hourly wind capacity factors (hourly MW output as a percentage of installed capacity) associated with the 100 highest net load hours (load minus wind output) for the 2015/2016–2019/2020 winter peak load seasons.
- **Operational Mitigations.** Additional resources (e.g., switchable generation resources, additional imports, voltage reduction, and mothballed capacity) to support maintaining operating reserves that are not already counted in WRA reserve margins

Texas RE-ERCOT Resource Adequacy Data

Demand, Resource, and Reserve Margins	2019–2020 WRA	2020–2021 WRA	2019–2020 vs. 2020–2021 WRA
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	62,257	57,699	-7.3%
Demand Response: Available	2,685	2,764	2.9%
Net Internal Demand	59,572	54,935	-7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	79,741	80,715	1.2%
Tier 1 Planned Capacity	1,191	1,359	14.1%
Net Firm Capacity Transfers	50	210	320.0%
Anticipated Resources	80,982	82,284	1.6%
Existing-Other Capacity	509	614	20.6%
Prospective Resources	82,284	82,898	0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	35.9%	49.8%	13.9
Prospective Reserve Margin	38.1%	50.9%	12.8
Reference Margin Level	13.75%	13.75%	0.0

Highlights

- ERCOT anticipates no reliability issues for the upcoming winter season and should have sufficient generation resources available to meet system-wide peak demand. ERCOT's expected winter peak load accounts for an economic growth projection prepared in April 2020.
- ERCOT also expects to have sufficient resources under scenarios that assume low wind output as well as extreme peak load conditions with an associated increase in unit outages and derates due to weather-related natural gas supply disruptions.
- An additional 5,424 MW of planned natural gas, wind, and solar capacity is projected to be added by the start of the winter season based on developer information provided to ERCOT. This amount equates to 1,359 MW of capacity available during winter peak load periods.
- Texas RE and ERCOT conducted their ninth winter Generator Weatherization Workshop on September 3, 2020, where generator operators and plant engineers presented their experiences with recent extreme weather events and covered lessons learned, best practices, and reliability improvements.

WECC

WECC is responsible for coordinating and promoting Bulk Electric System reliability in the Western Interconnection. WECC's 329 members, which include 38 Balancing Authorities, represent a wide spectrum of organizations with an interest in the Bulk Electric System. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is geographically the largest and most diverse of the NERC Regional Entities. 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, and all or portions of the 14 Western United States in between.

The WECC assessment area is divided into six areas: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), the Northwest Power Pool (NWPP), and the Canadian areas of Alberta (WECC AB) and British Columbia (WECC BC). These area divisions are used for this study as they are structured around reserve sharing groups that have similar annual demand patterns and similar operating practices.

WECC Resource Adequacy Data

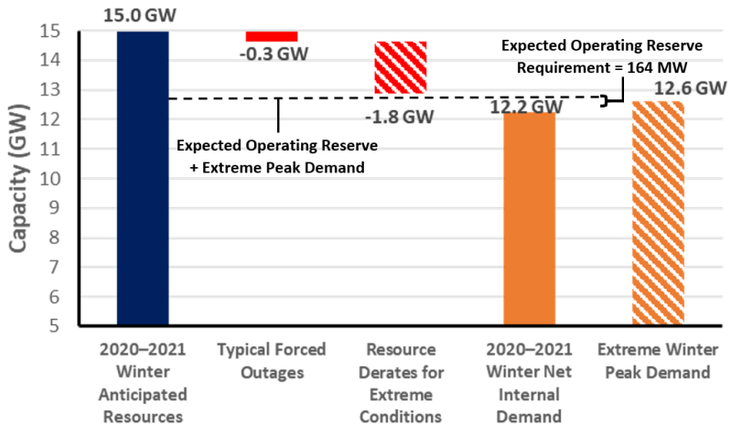
Demand, Resource, and Reserve Margins	WECC AB	WECC BC	CA/MX	NWPP & RMRG	SRSG	2019–2020	2020–2021	2019–2020 vs. 2020–2021 WRA
Demand Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**Total MW**	**Total MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,248	11,151	39,382	56,899	16,355	136,939	136,035	-0.7%
Demand Response: Available	0	0	859	546	62	1,503	1,467	-2.4%
Net Internal Demand	12,248	11,151	38,523	56,354	16,293	135,436	134,568	-0.6%
Resource Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**Total MW**	**Total MW**	**Net Change (%)**
Existing-Certain Capacity	14,974	13,321	50,018	76,654	28,522	178,476	183,489	2.8%
Tier 1 Planned Capacity	0	0	0	0	0	482	0	-100.0%
Net Firm Capacity Transfers	0	0	0	0	0	700	0	-100.0%
Anticipated Resources	14,974	13,321	50,018	76,654	28,522	179,658	183,489	2.1%
Existing-Other Capacity	0	0	0	0	0	0	0	0.0%
Prospective Resources	14,974	13,321	50,018	76,654	28,522	180,154	183,489	1.9%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	22.3%	19.5%	29.8%	36.0%	75.1%	32.7%	36.4%	3.7
Prospective Reserve Margin	22.3%	19.5%	29.8%	36.0%	75.1%	33.0%	36.4%	3.4
Reference Margin Level	12.5%	12.5%	8.5%	18.0%	13.0%	11.7%	12.9%	1.2

Highlights

- WECC anticipates that its five assessment areas and all zones within the footprint will meet or exceed their respective Reference Margin Level and maintain resource adequacy through the 2020–2021 winter season.
- Winterization techniques are implemented throughout the freezing zones to mitigate against severe weather or unexpected equipment failure. National Weather Service models predict mild temperature and precipitation conditions in the Western Interconnection.

WECC-Alberta

Seasonal Risk Scenario

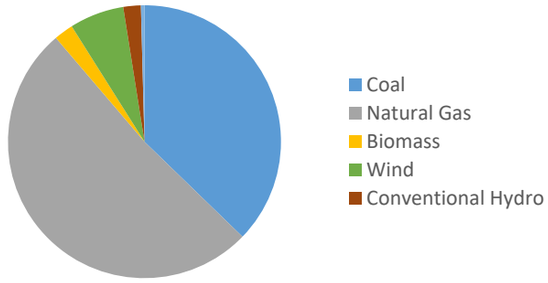


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

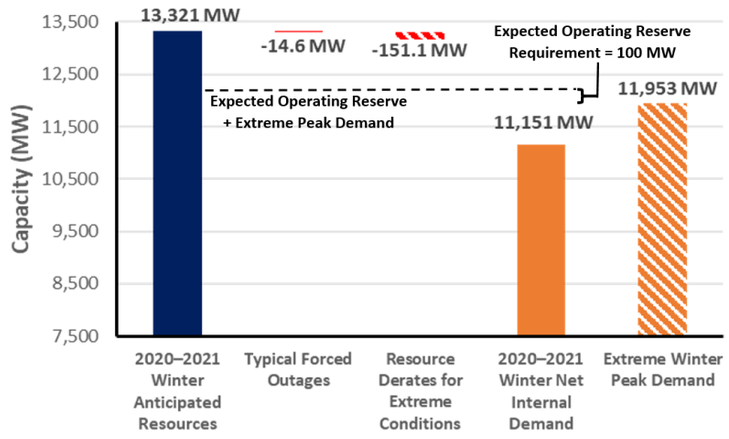
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the tenth percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



On-Peak Generation Fuel Mix

WECC-British Columbia

Seasonal Risk Scenario

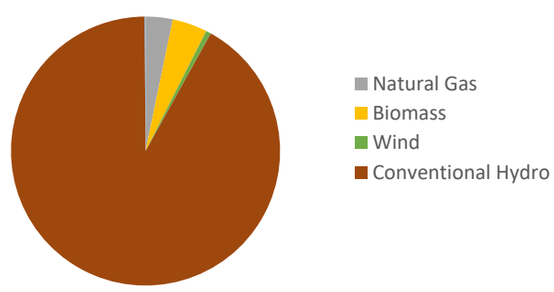


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

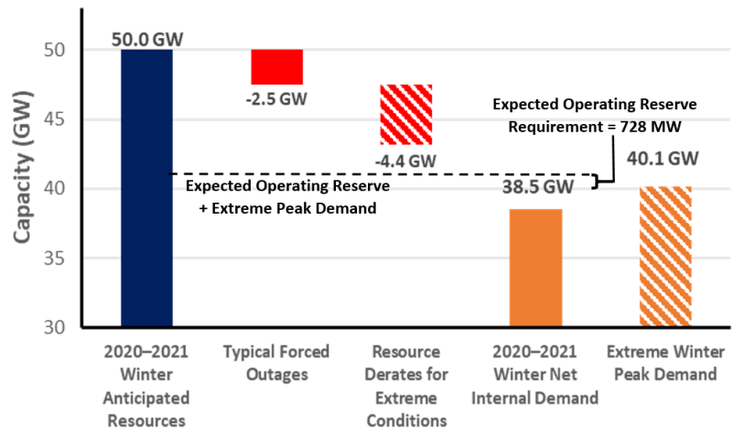
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the tenth percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



On-Peak Generation Fuel Mix

WECC-California/Mexico

Seasonal Risk Scenario

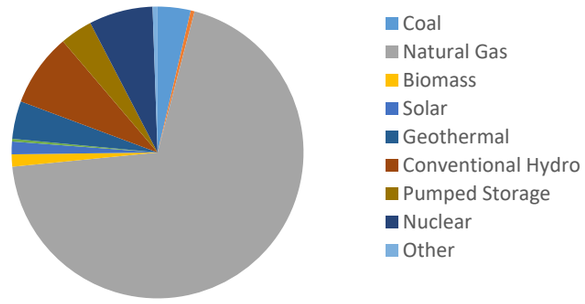


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

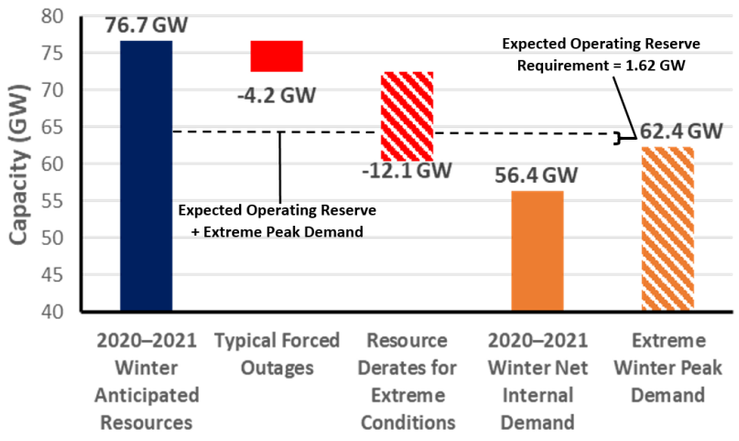
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the tenth percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



On-Peak Generation Fuel Mix

WECC- Northwest Power Pool & Rocky Mountain Reserve Sharing Group

Seasonal Risk Scenario

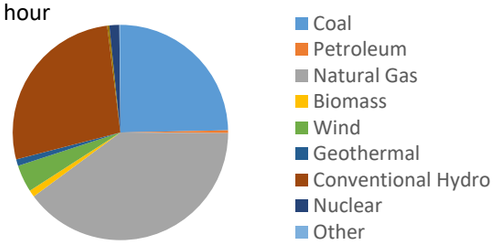


Risk Scenario Summary

Resources meet operating reserve requirements for typical outage conditions, peak load, and extreme peak loads. Extreme outages may result in insufficient resources at peak load.

Scenario Assumptions

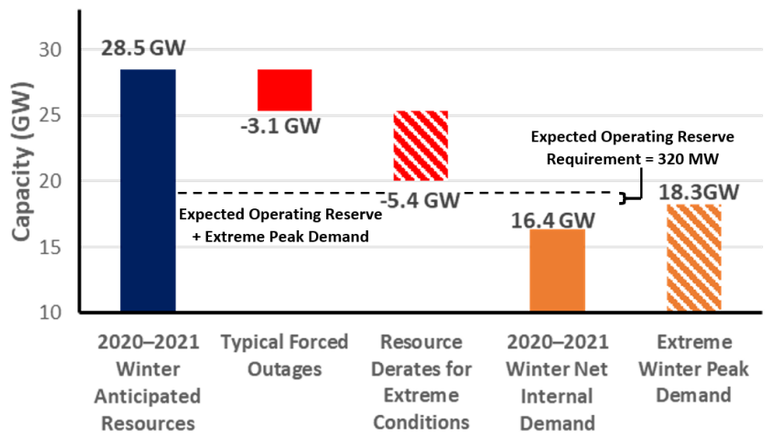
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the tenth percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



On-Peak Generation Fuel Mix

WECC-Southwest Reserve Sharing Group

Seasonal Risk Scenario

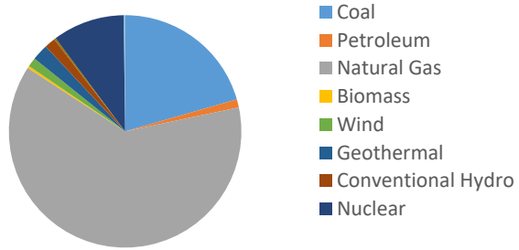


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Developed using the tenth percentile availability curves for the thermal, wind, and solar resources at the assessment area peak hour



On-Peak Generation Fuel Mix

Data Concepts and Assumptions

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

General Assumptions

- Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
  - Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
  - Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
- The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
- All data in this assessment is based on existing federal, state, and provincial laws and regulations.
- Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
- 2020 Long-Term Reliability Assessment data has been used for most of this Winter 2020–2021 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[9] or total internal demand for the summer and winter of each year.[10]
- Total internal demand projections are based on normal weather (50/50 distribution[11]) and are provided on a coincident[12] 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 following categories to provide a consistent approach for collecting and presenting resource adequacy:

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 (PPA) 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.

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

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

[11] 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.

[12] 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.

Reserve Margin Definitions

Reserve margin 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.

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 Assessment 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 (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 are distinguished with striped bars (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, 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 low-probability, extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme winter peak demand. Because such extreme scenario analysis depicts the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of this scenario is very low.