BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-26:
Wash. Dep't of Commerce Summary of Utilities' 2024 IRPs (Dec. 1, 2025)

Washington State Electric Utility Resource Planning

2024 Report

December 2025

Report to the Legislature

Director Joe Nguyễn

ENERGY POLICY OFFICE

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Table of contents

Executive summary

Overview

Chapter 19.280 RCW requires electric utilities develop resource plans to assess their specific future load and resource requirements. The Department of Commerce is tasked with collecting and analyzing the utility resource plans and creating a summary report for the Legislature.[1]

This report is required biennially per RCW 19.280.060, which states:

> The department shall review the plans of consumer-owned utilities and investor-owned utilities, and data available from other state, regional, and national sources, and prepare an electronic report to the legislature aggregating the data and assessing the overall adequacy of Washington's electricity supply. The report shall include a statewide summary of utility load forecasts, load/resource balance, and utility plans for the development of thermal generation, renewable resources, conservation and efficiency resources, and an examination of assessment methods used by utilities to address overgeneration events. The commission shall provide the department with data summarizing the plans of investor-owned utilities for use in the department's statewide summary. The department shall submit any reports it receives of existing and potential combined heat and power facilities as reported by utilities to the Washington State University extension energy program for analysis. The department may submit its report within the biennial report required under RCW 43.21F.045.

Key findings

This report collects and summarizes data from Washington state utilities' 2024 resource plans. The 2024 Utility Resource Plan Report summarizes the findings of Washington state load and resource information for a 10-year planning cycle — with most utilities using 2023 as the base year. This report does not reflect state or federal policy changes post-2024. Key findings of the 2024 Utility Resource Plan report are:

- Utilities plan to reduce their use of coal-fired electricity generation and market purchases serving Washington retail customers in the forecast periods, and to increase their use of hydropower, wind power, and utility-scale solar. Hydropower will remain the dominant source of electric for Washington utilities over the 10-year forecast period.
- Following successive years of stagnant or declining load forecasts, many utilities anticipate modest load growth driven by population growth and transportation and building electrification over the next five to ten years. In addition, the Mid-Columbia utilities (Grant, Douglas, and Chelan public utility districts) forecast significant load growth from data centers.
- Utilities anticipate a decline in savings potential from energy efficiency and conservation compared to past resource plans due to building and appliance codes and standards, market saturation of efficient technologies, and load growth from electrification.

Most utilities plan to meet load requirements in the lowest-cost, least-risk way by renewing Bonneville Power Administration contracts (for slice or block products or shifting to a load-following product), pursuing new renewable resources, and maximizing energy conservation measures. While several consumer-owned utilities plan to remove natural gas from their resource portfolios in the next five and ten years, investor-owned utilities plan to maintain relatively steady amounts of natural gas in their resource portfolio.

[1] Section 19.280.060, Department's duties—Report to the legislature. (2025). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.060.

Assessments of resource adequacy from regional experts conclude the Northwest has adequate resources to meet current demand for electricity and does not face a significant risk of outages in the near term. However, these assessments assume the industry will be able to execute their planned capacity expansions. Confidence in these assessments is also limited by the increasing level of uncertainty that planners face about future demand for electricity. The sources of this uncertainty include the added volatility of our weather, the pace of consumer conversion to electricity for transportation, heating and other end uses, changing federal and state policies, and the growing energy demands of data centers.

The Clean Energy Transformation Act (CETA), Washington's 100% clean electricity law, includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance. While resource adequacy is an obligation of each electric utility serving end use customers in the state, it also is a shared responsibility of the overall electric power system and the entities that operate, plan, regulate, design, and fund the generation, transmission, and delivery of that system. As utilities reduce reliance on coal-fired and gas-fired power plants and add variable renewable energy such as wind and solar, new approaches and resources will be required to maintain resource adequacy to ensure reliable service to customers. It is equally important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outage risks.

Introduction

Background

Washington consumers and businesses depend on electricity service from more than 60 electric utilities operating in this state. These utilities vary greatly in size, geographic scope, history and governance, but each is responsible for ensuring an adequate supply of an essential resource.

Washington law requires each utility to plan for the future by examining the projected amounts of electricity that will be required by customers in the coming decade and identifying the power resources that will be used to meet those demands.[2] Each utility must prepare a report every two years and submit it to Commerce. Commerce reviews the utility reports and submits a summary to the Legislature. This is the ninth report since the Legislature enacted the resource planning law in 2006. This report collects and summarizes data from Washington state utilities' 2024 resource plans. Data collection was completed in early 2025.

Depending on their size and power sources, utilities submit either a resource plan (RP) or an integrated resource plan (IRP). The RP is a short-form report of load[3] and resources and may be submitted only if the utility has fewer than 25,000 customers or is a full requirements customer"[4] of Bonneville Power Administration. The IRP is a more detailed plan and must incorporate a number of specific requirements identified in statute.

Purpose

Utilities develop resource plans to assess their future load and resource situations. This report aggregates the individual utility submittals to provide an assessment at the statewide level of whether utilities are planning for adequate supplies, and what resources are expected to meet any growth in electric power demand. The Legislature has asked Commerce to provide this review and oversight of the resource planning process so that they can understand and assist in meeting the state's electricity needs.

This report summarizes the electricity loads and resources reported by Washington utilities in their 2024 reports to Commerce. It compares them to estimated summaries of previous years. Resources proposed to meet load are categorized by generating fuel type and source type, i.e. "hydropower" or "market purchase." An imbalance of loads and resources may indicate either a resource surplus or deficit.

The information collected for this report is limited to the identification of loads and resources and their associated aggregate quantities. It does not attempt to evaluate specific goals or outcomes for resource acquisition strategies used by utilities.

This report provides information on utilities' energy efficiency and renewable energy resources. It does not analyze issues related to the energy efficiency and renewable energy requirement of, or compliance with, the Energy Independence Act (Chapter 19.285 RCW) or the Clean Energy Transformation Act (Chapter 19.405 RCW). It also does not evaluate the impacts of new state or federal policies after 2024 which may contradict the assumptions utilized in the utility resource plans, regional resource adequacy assessments, or regional forecasts summarized in this report.

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[2] Chapter 19.280 Electric Utility Resource Plans. (2025). Retrieved from Revised Code of Washington

[3] As used in the statute and this report, "load" means the amount of electric energy demanded by a utility's customers during a defined period.

[4] Full requirements customer as defined in Section 19.280.020(7) means an electric utility that relies on the Bonneville Power Administration for all power needed to supply its total load requirement other than that served by nondispatchable generating resources totaling no more than six megawatts or renewable resources.

Utility reporting

The utility resource planning statutes (Chapter 19.280 RCW) require that each utility prepare a resource plan (RP) and submit it to Commerce by Sept. 1 of each even-numbered year. Commerce received reports from 61[5] utilities. The individual reports are presented in Appendix A: Utility cover sheets. A summary of electricity sales to customers is presented in Appendix B: Washington utility customer count, revenue, sales, and average price. A glossary of terms is provided in Appendix C: Glossary of terms.

Electric utilities in Washington vary significantly in size and the scope of operations. This is reflected in the way utilities approach resource planning and forecasting. Larger utilities typically use multiple sources of electricity supply to meet their customers' requirements and engage in sophisticated assessments of risks and benefits in evaluating alternative sources of new energy. Many smaller utilities rely on the Bonneville Power Administration, which undertakes the complex planning and forecasting exercise that leads to a resource plan.

The resource planning statute reflects this difference in approaches. As mentioned previously, it requires that larger utilities prepare and submit IRPs, which are the product of a thorough assessment of future needs and alternatives for meeting those needs through both demand-side and supply-side resources. Smaller utilities are allowed to prepare and submit a simplified assessment of loads and resources.

Interpretation of base year, five-year and 10-year data

The resource plan summary submitted to Commerce includes load and resource information for three points in a 10-year planning cycle. These points are the base year, five-year and 10-year plans. In 2024, most utilities used 2023 as the base year, and the five-year and 10-year points are 2028 and 2033, respectively. However, utilities vary in their planning cycles, and some utilities use an earlier or later set of years in their reporting; the base year ranges from 2022 to 2024. For purposes of the statewide summary, Commerce aggregates all base-year data into a single value (2023) and does likewise for the five-year (2028) data and 10-year data (2033).

Interpretation of conservation and load data

An important principle of integrated resource planning is that all resources should be evaluated on a consistent basis. This includes different generating resources, such as wind and natural gas, as well as energy conservation measures and demand response resources. With energy conservation measures and demand response being analyzed and compared to supply-side options, utilities determine whether customers are better served by increasing energy efficiency, demand reduction, or energy supply. Consequently, energy conservation measures are sometimes portrayed as a reduction in the utility's load and sometimes portrayed as resources available to meet load. This can lead to confusion in interpreting utility plans.

Here is how this potential confusion is resolved:

> Utilities report a base year load amount that reflects whatever conservation has occurred in the past. For the five-year and 10-year values, utilities are directed to report the load that they would expect to serve in the absence of any additional conservation savings, demand response, and behind-the-meter solar (BTM solar). The report separately lists the conservation resources, demand response, and BTM solar that the utility expects during the five-year and 10-year periods.

[5] Commerce did not receive a resource plan coversheet from Consolidated Irrigation District #19 for 2024.

In summary, the amounts reported as load for the five-year and 10-year intervals are based on an assumption of no new conservation, demand response, or BTM solar. The actual loads at these future time points are likely to be lower by the amount of energy conservation, demand response, and BTM solar identified by each utility.

Results

The 2024 resource plans submitted to Commerce are summarized in Table 1-4 and Figures 1-2.

Table 1 presents utility report information in units of average-Megawatts (aMW)[6] on statewide annual utility load and resources, including imports and exports, for the base year (2023), and the five and 10-year forecasts. The right two columns in the table illustrate the difference between the base year and the five and 10-year forecasts. Table 1 also presents the composition of electric generation resources for the base year, and the five and 10-year forecasts. Table 1 shows the five and 10-year forecast for load growth is nearly double the amount presented from two years ago, most of which comes from data center load growth in Chelan, Grant, and Douglas counties.

In this year of reporting, Commerce asked utilities to disaggregate "other renewable resources." We can see that the use of biomass and utility-scale solar was nearly equal in the base year (55 and 56 aMW respectively), but utilities are expecting substantial growth in utility-scale solar in the next five to 10 years as the use of biomass resources remains steady.

Table 1: Washington's projected requirements and resources - annual energy aMW

Requirements	Base Year	5-year Forecast	10-year Forecast	5-year Change	10-year Change
Loads	10,189	11,316	12,245	1,128	2,057
Exports	746	513	423	(234)	(323)
Energy Conservation Measures	No data	(336)	(790)	(336)	(790)
Demand Response	No data	(42)	(57)	(42)	(57)
BTM Solar	0	(26)	(52)	(26)	(52)
Total Net Requirements	**10,935**	**11,425**	**11,770**	**490**	**835**

Resources	Base Year	5-year Forecast	10-year Forecast	5-year Change	10-year Change
Total BPA	4,511	4,844	4,985	333	474
Hydro	3,044	3,513	3,878	469	834
Thermal Natural Gas	1,101	1,206	855	105	(246)
Market Purchases	934	327	132	(607)	(802)
Thermal Coal	450	No data	No data	(450)	(450)
Other	850	196	161	(654)	(689)
Wind	811	1,059	1,625	248	814
Imports	237	259	301	22	64
Cogeneration	2	2	2	No data	No data
Biomass	55	62	62	7	7

[6] aMW, or average megawatt, is an amount of electric energy equal to one megawatt-hour per hour for an entire year, or 8,760 megawatt-hours.

Resources	Base Year	5-year Forecast	10-year Forecast	5-year Change	10-year Change
Utility-scale Solar	56	363	499	307	443
Other Distributed Renewables	25	25	25	(0)	(0)
Geothermal	2	2	102	(0)	99
Landfill Gas	1	7	9	6	8
Undecided	No data	175	94	175	94
FTM Distributed Solar	No data	1	1	1	1
Nuclear	No data	No data	24	No data	24
Biogas	No data	No data	No data	No data	No data
Total Resources	12,079	12,446	13,654	367	1,575
Load Resource Balance	1,144	1,021	1,884	(123)	740

Figure 1 presents the composition of electric generation resources for the five-year and 10-year forecasts. Table 1 and Figure 1 show that utilities plan to continue relying mostly on Bonneville Power Administration (BPA), hydroelectric generation, and thermal natural gas plants to meet electricity demand. The BPA resource is a blended resource and is typically 85% hydropower, 11% nuclear, and 4% unspecified market purchases.

While several consumer-owned utilities plan to remove natural gas from their resource portfolios in their five-year forecast, all the investor-owned utilities forecast relatively steady amounts of natural gas in their resource portfolios. For the first time since reporting started, Washington utilities forecast that wind power will surpass thermal natural gas plants in meeting their 10-year resource need.

Figure 1: Forecast available resources

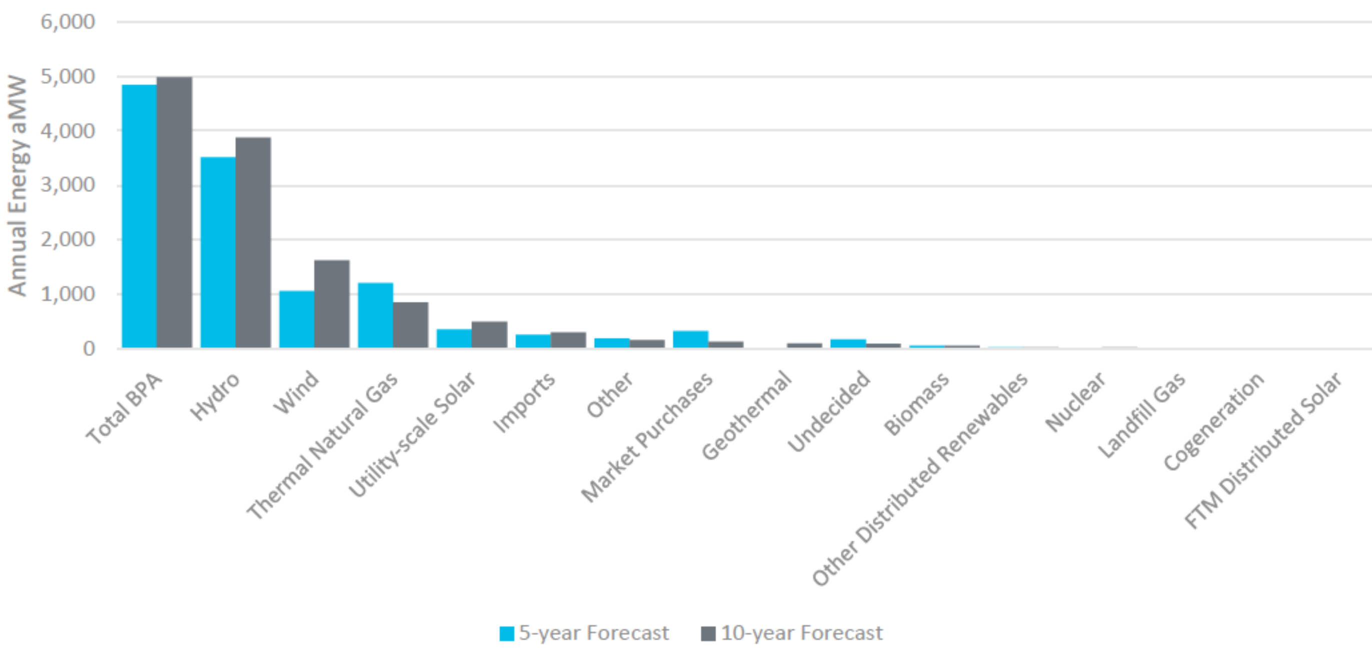


Table 2 presents in average-megawatts the differences between the 2022 and 2024 resource reports on statewide annual utility load and resources and the five and 10-year forecasts. Table 2 shows a diminished contribution from coal-fired electricity generation and natural gas-fired generation in the forecast period, and an increased reliance on BPA resources, hydropower, wind, imports, and other renewables.

Table 2: Difference between 2024 and 2022 requirements and resources — annual energy aMW

Requirements	Base Year	5-year Forecast	10-year Forecast
Loads	(14)	499	882
Exports	520	295	233
Energy Conservation Measures	No data	(70)	(26)
Demand Response	No data	18	24
BTM Solar	No data	26	52
Total Net Requirements	**507**	**819**	**1,066**

Resources	Base Year	5-year Forecast	10-year Forecast
Total BPA	151	352	316
Hydro	363	197	325
Thermal Natural Gas	(1,591)	(1,357)	(1,578)
Market Purchases	718	249	18
Other	(266)	(44)	(19)
Wind	173	(11)	599
Thermal Coal	(275)	(156)	(67)
Imports	148	203	250
Other Renewables	(29)	91	127
Distributed Generation	20	39	57
Cogeneration	(13)	(13)	(13)
Undecided	No data	174	82
Nuclear	No data	No data	24
Total Resources	(454)	28	685
Load Resource Balance	(961)	(791)	(380)

The shift in electric generation resources suggests progress towards meeting the requirements of the Clean Energy Transformation Act (CETA). CETA prohibits utilities from using coal generation after 2025.[7] CETA requires all retail sales of electricity to Washington be greenhouse gas neutral by 2030[8] and 100% non-emitting by 2045.[9]

[7] Section 19.405.030(1) Coal-fired resources-Depreciation schedule-Penalties. (2025). Retrieved from Revised Code of Washington.
[8] Section 19.405.040(1) Greenhouse gas neutrality-Responsibilities for electric utilities-Energy transformation project criteria-Penalties. (2025). Retrieved from Revised Code of Washington.
[9] Section 19.405.050(1) Clean energy implementation-Hydroelectric facilities-Special contracts. (2025). Retrieved from Revised Code of Washington.

Table 3 presents utilities' aggregated report information for their highest estimated one-hour load during the winter season,[10] including imports and exports, for the base year (2023), and the five and 10-year forecasts. In the past, utilities forecasted more reliance on market purchases to meet peak demand, but utilities are increasingly aiming to decrease their reliance on short-term wholesale electricity markets (market purchases). The availability of dispatchable generation resources is declining and market power prices and volatility is increasing, especially during peak demand periods when prices can be high and supply uncertain.[11] Utilities are exploring various solutions, including demand response programs, energy efficiency measures, and new generation resources.

Table 3: Washington projected requirements and resources — winter capacity MW

Requirements	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Loads	14,584	15,976	17,224	1,391	2,640
Exports	1,093	802	741	(291)	(352)
Energy Conservation Measures	No data	(404)	(896)	(404)	(896)
Demand Response	No data	(387)	(526)	(387)	(526)
BTM Solar	0	(12)	(16)	(12)	(16)
Total Net Requirements	15,678	15,975	16,526	297	848

Resources	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Hydro	5,171	6,195	6,750	1,024	1,578
Total BPA	4,334	4,725	4,808	391	474
Thermal Natural Gas	3,182	3,008	3,001	(174)	(181)
Other	1,878	1,300	1,340	(578)	(538)
Market Purchases	1,598	225	200	(1,373)	(1,398)
Wind	770	1,420	1,953	649	1,183
Imports	654	526	584	(128)	(70)
Thermal Coal	596	No data	No data	(596)	(596)
Biomass	59	66	66	7	7
Other Distributed Renewables	26	26	26	No data	No data
Utility-scale Solar	20	527	544	507	524
Cogeneration	5	90	90	85	85
Landfill Gas	2	8	11	6	9
Geothermal	2	2	102	(0)	100
Undecided	No data	80	No data	80	No data
Nuclear	No data	No data	30	No data	30
FTM Distributed Solar	No data	0	0	0	0
Biogas	No data	No data	No data	No data	No data

[10] Table 1 expressed in energy units of aMW, Table 3 in capacity units of MW.
[11] Puget Sound Energy. (2023, Chapter 1, p. 5). Electric Progress Report.

Resources	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Total Resources	18,297	19,000	20,943	703	2,646
Load Resource Balance	2,619	3,025	4,417	405	1,798

Most Washington utilities experience their annual peak load during the winter months; however, due to climate change, utilities anticipate less heating required in the winter and more cooling required during the summer. Table 4 presents utilities' aggregated report information for their highest estimated one-hour load during the summer season, including imports and exports, for the base year (2023), and the five and 10-year forecasts.

Warmer average summer temperatures and more frequent and intense heat waves are leading to increased demand for air conditioning and cooling, directly driving up electricity consumption during summer peak hours. For instance, Puget Sound Energy (PSE) noted that incorporating climate change data into their demand forecast resulted in increased summer peak temperatures and thus, increased summer demand.[12] Avista anticipates needing to prepare for a near-term future as a dual summer and winter peaking utility due to these trends.[13]

Table 4: Washington projected requirements and resources - summer Capacity MW

Requirements	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Loads	11,996	13,911	15,517	1,915	3,520
Exports	1,427	1,385	1,295	(42)	(133)
Energy Conservation Measures	No data	(392)	(854)	(392)	(854)
Demand Response	No data	(400)	(539)	(400)	(539)
BTM Solar	0	(83)	(122)	(83)	(122)
Total Net Requirements	13,424	14,421	15,296	998	1,872

Resources	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Hydro	5,392	6,262	6,509	870	1,117
Total BPA	3,301	3,421	3,582	120	281
Thermal Natural Gas	2,681	2,515	2,508	(166)	(173)
Other	1,541	1,249	1,248	(292)	(293)
Market Purchases	1,778	248	200	(1,530)	(1,578)
Wind	547	1,216	1,759	669	1,212
Imports	282	222	280	(60)	(2)
Thermal Coal	595	No data	No data	(595)	(595)
Biomass	59	66	66	7	7
Other Distributed Renewables	22	22	22	No data	No data
Utility-scale Solar	84	966	1,022	882	938

[12] Puget Sound Energy. (2023, Chapter 3, p. 14). Electric Progress Report.
[13] Avista. (2023, Chapter 2, p. 21). Electric Integrated Resource Plan.

Resources	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Cogeneration	4	4	89	No data	85
Landfill Gas	2	9	11	7	9
Geothermal	2	2	102	(0)	100
Undecided	No data	128	No data	128	No data
Nuclear	No data	No data	31	No data	31
FTM Distributed Solar	No data	1	2	1	2
Biogas	No data	No data	No data	No data	No data
Total Resources	16,290	17,206	18,946	916	2,656
Load Resource Balance	2,866	2,784	3,649	(82)	783

Figure 2 shows Washington utilities' 10-year (2033) projected resources by utility ownership type. Most consumer-owned utilities (public utility districts, municipal, and cooperatives) rely predominantly on BPA resources and hydropower; however, municipal utilities forecast a higher use of wind power and energy conservation measures than other consumer-owned utilities. Investor-owned utilities plan to rely on baseload natural gas generation for approximately 20% of their 10-year projected resources; however, they plan to reduce their natural gas generation by approximately 16% compared to the base year of 2023.

Figure 2: Washington 10-year projected resources by utility ownership type

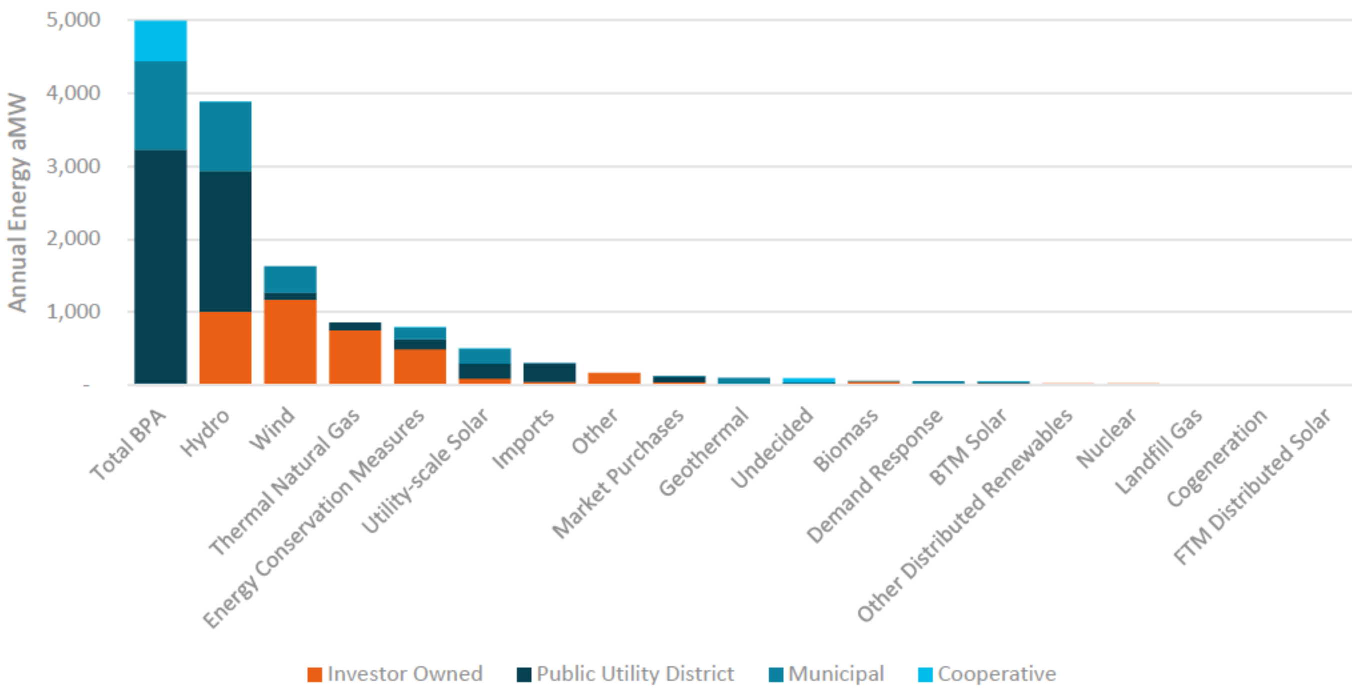


Table 5 presents a time series of Commerce Utility Resource Plans. The information in the table presents aggregated annual utility loads (base year, five-year and 10-year) for the 2008 through 2024 Commerce reports. The forecast loads do not include the energy conservation measure (ECM) forecast by utilities. Figure 3 presents the information in Table 5 in a graphical format. Table 6 and Figure 4 present the aggregated annual utility loads (base-year, five-year and 10-year) and include energy conservation measures (ECM), demand response (DR), and behind-the-meter (BTM) solar forecasts by utilities.

Table 5 and 6 and Figure 3 and 4 show load growth forecasts by utilities for the five and 10-year points which have typically trended down with each successive report; however, this year, the forecasts do not follow the trend. This is due to new high load growth rates from factors, such as data center growth, population growth, and electrification.

The Mid-Columbia utilities, Grant, Chelan, and Douglas PUDs, are forecasting high load growth rates due to the growth of data centers, computing demand, cryptocurrency mining, and industrial load.

Chelan County PUD forecasts a very high average annual growth rate of 31.71%, 31.88%, and 32.23% for High Density Loads[14], cryptocurrency processing, and large loads during the planning period.[15]

For Grant County PUD, over the past the twenty years, industrial class load growth has made up an ever-increasing portion of their total retail load, and data centers have grown to dominate load growth in that sector. Industrial loads have transitioned from a 28% share twenty years ago to a 47% share of total Grant PUD load today.[16]

Over the last decade, Douglas PUD experienced a load growth of 76% principally due to large loads.[17] Douglas PUD expects elevated levels of load growth to continue. Douglas PUD reports it has instituted a number of policies to curb risk associated with data loads. One of these policies requires large contract customers to enter into special contracts that mitigate risk associated with transmission and distribution build-out by requiring customers to pay for all required infrastructure upgrades upfront.[18]

Other utilities are also predicting increasing load growth (though not at the very high rates from data centers, computing demand, cryptocurrency mining, and industrial and manufacturing growth) due to electrification of buildings and transportation and population growth. Clark Public Utilities (CPU) projects an average year-over-year load growth of 1.98%, with a high scenario reaching 3.12% for 2025-2044. The load forecast in CPU's study incorporates additional load growth due to building and vehicle electrification beyond what has been seen historically. Over the study period, CPU shifts from a predominantly winter-peaking utility to a summer-peaking utility. CPU is currently forecast to have sufficient resources available to meet average energy demand through 2035. However, on a capacity basis, CPU is currently at a deficit and is projected to grow that deficit to roughly 750 MW of summer capacity and 500 MW of winter capacity by the end of the study period absent additional resource procurement. That deficit is partially exacerbated by the additional capacity required to comply with the Western Resource Adequacy Program (WRAP), which is modeled to take effect in November 2027.[19] Moreover, Puget Sound Energy (PSE) primarily serves residential and commercial customers, and it expects energy demand to grow an average rate of 1.8 percent annually from 2024-2045.[20] Rising customers and electric vehicle counts drive most of the growth in energy demand for PSE. This demand growth is partially, but not entirely, offset by decreasing residential heating energy demand — a consequence of adopting trended normal temperatures consistent with climate change impacts.

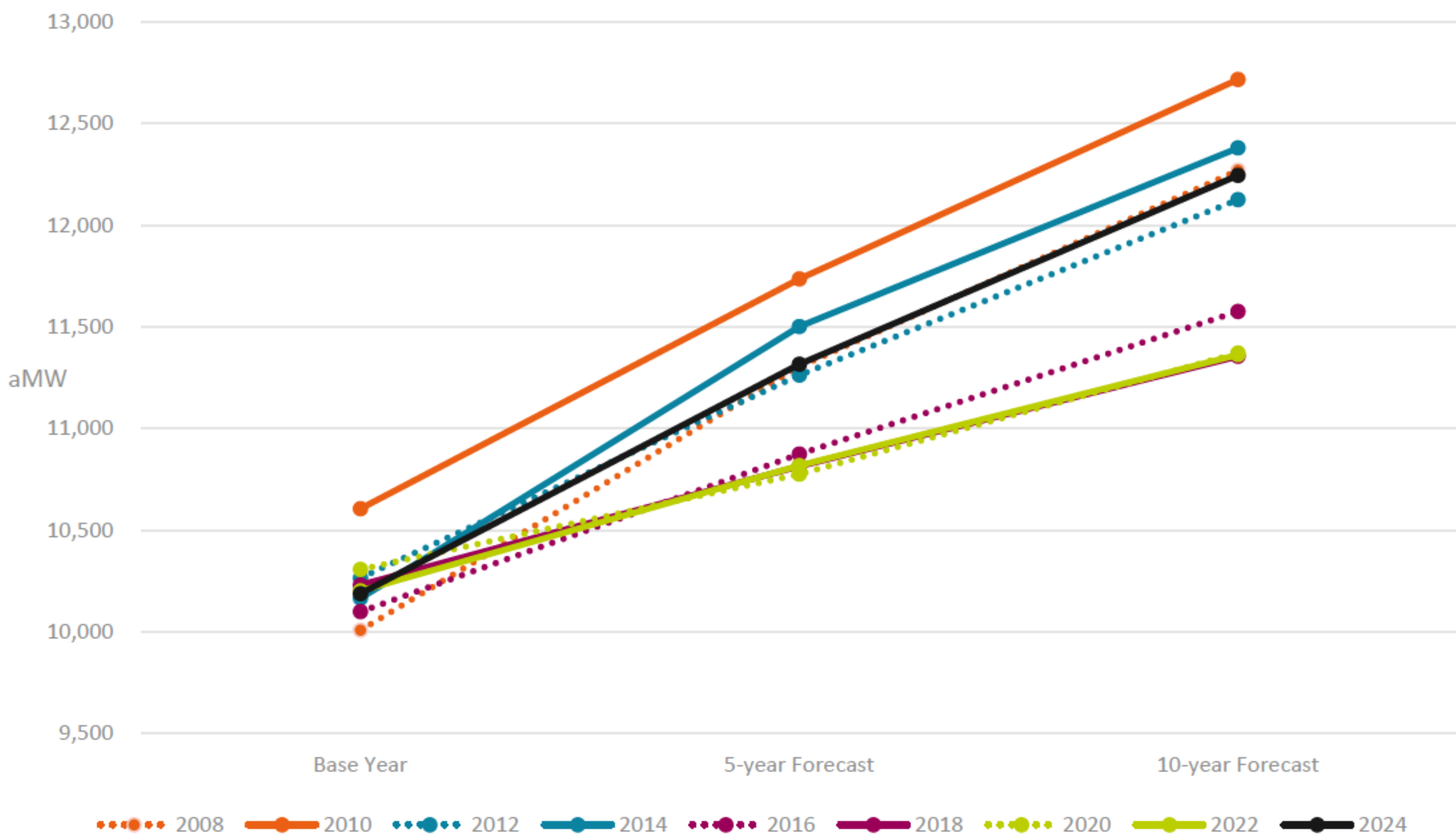
Table 5: Utility report time series — base year and forecast loads without ECM

Utility Report Year	Base Year	Base Year, aMW	5-year Est.	5-year Est. aMW	10-year Est.	10-year Est. aMW
2008	2007	10,008	2012	11,304	2017	12,270

[14] These are typically server farms and similar technological operations.
[15] Chelan PUD. (2023, p. 15-16). Integrated Resource Plan Progress Report.
[16] Grant PUD. (2024, p. 54). Integrated Resource Plan.
[17] Douglas PUD. (2024, p. 6). Integrated Resource Plan Update.
[18] Douglas PUD. (2024, p. 7). Integrated Resource Plan Update.
[19] Clark Public Utilities. (2024, p. 6). Integrated Resource Plan.
[20] Puget Sound Energy. (2023, Chapter 6, p. 1). Electric Progress Report.

Utility Report Year	Base Year	Base Year, aMW	5-year Est.	5-year Est. aMW	10-year Est.	10-year Est. aMW
2010	2009	10,606	2014	11,737	2019	12,717
2012	2011	10,265	2016	11,264	2021	12,126
2014	2013	10,166	2018	11,502	2023	12,380
2016	2015	10,099	2020	10,875	2025	11,576
2018	2017	10,231	2022	10,816	2027	11,356
2020	2019	10,307	2024	10,775	2029	11,372
2022	2021	10,202	2026	10,818	2031	11,363
2024	2023	10,189	2028	11,316	2033	12,245

Figure 3: Utility report time series — base year and forecast loads without ECM



By comparing, Table 5 and 6 as well as Figure 3 and 4 it is evident that utility conservation programs significantly reduce aggregate load growth.

Table 6: Utility report time series — base year and forecast loads with ECM, DR, and BTM solar

Utility Report Year	Base Year	Base Year, aMW	5-year Est.	5-year Est. aMW	10-year Est.	10-year Est. aMW
2008	2007	10,008	2012	10,890	2017	11,524
2010	2009	10,555	2014	11,145	2019	11,691
2012	2011	10,265	2016	10,692	2021	11,107
2014	2013	10,166	2018	11,017	2023	11,423
2016	2015	10,099	2020	10,347	2025	10,629
2018	2017	10,231	2022	10,345	2027	10,582
2020	2019	10,307	2024	10,272	2029	10,548
2022	2021	10,202	2026	10,389	2031	10,514
2024	2023	10,189	2028	10,912	2033	11,347

Figure 4: Utility report time series — base year and forecast loads with ECM, DR, and BTM solar

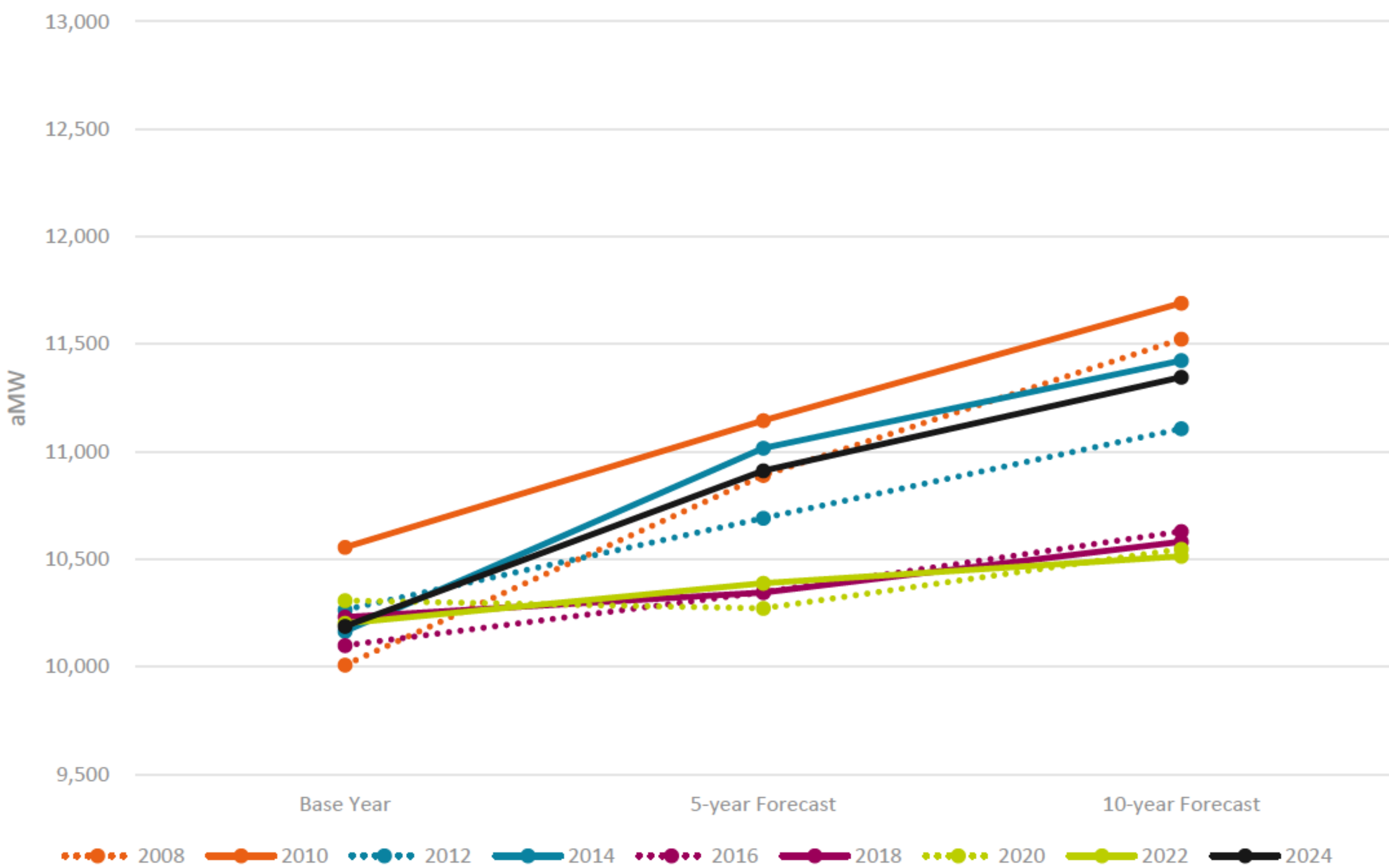


Table 7 presents the individual utility growth forecasts and the percentage of load growth anticipated to be met by energy conservation measures. The average load growth with no conservation across utilities has more than doubled compared to the 2022 resource plan report. The average 5-year load growth with no conservation increased from 3.2% in 2022 to 8.5% in 2024, and the average 10-year load growth with no conservation increased from 6.2% in 2022 to 15.5% in 2024. Most of this load growth comes from data centers, computing demand, and cryptocurrency mining in the service territories of Chelan County PUD, Douglas County PUD, and Grant County PUD.

Table 7: Individual utility load forecasts without conservation and with conservation

Utility Name	5-year load growth change % without conservation	10-year load growth change % without conservation	5-year load growth change % met by conservation	10-year load growth change % met by conservation
Asotin County PUD No. 1	6.01%	6.20%	0.00%	0.00%
Avista	6.12%	12.81%	47.63%	45.71%
Benton County PUD No. 1	-0.95%	2.34%	-239.74%	194.86%
Benton Rural Electric Assn	2.84%	7.27%	0.00%	0.00%
Big Bend Electric Cooperative	9.16%	11.60%	3.81%	3.01%
Blaine, City of	34.09%	46.81%	0.21%	0.15%
Centralia, City of	7.94%	9.23%	0.00%	0.00%
Chelan County PUD No.1	72.93%	140.13%	4.98%	6.36%
Cheney, City of	3.63%	7.19%	3.39%	1.71%
Chewelah, City of	-0.49%	-0.45%	-80.35%	-87.70%
Clallam County PUD No. 1	3.33%	8.13%	134.19%	109.77%
Clark Public Utilities	3.62%	12.50%	0.00%	0.00%
Columbia REA	0.74%	4.86%	0.00%	0.00%
Coulee Dam, Town of	1.02%	3.47%	0.00%	0.00%
Cowlitz County PUD No. 1	31.61%	32.21%	0.00%	0.00%
Douglas County PUD No. 1	106.98%	171.13%	0.00%	0.00%
Eatonville, Town of	0.00%	0.00%	0.00%	0.00%
Ellensburg, City of	8.29%	9.79%	5.76%	4.88%
Elmhurst Mutual Power and Light Company	0.72%	2.35%	150.00%	46.15%
Ferry County PUD	-1.07%	1.15%	-9.46%	8.79%
Franklin County PUD No. 1	23.87%	32.56%	0.00%	0.00%
Grant County PUD No. 2	37.89%	54.16%	2.50%	4.21%
Grays Harbor County PUD No. 1	9.33%	7.40%	0.00%	0.00%
Inland Power and Light	11.24%	21.75%	0.00%	0.00%
Jefferson County PUD No. 1	1.59%	2.84%	31.05%	17.35%

Utility Name	5-year load growth change % without conservation	10-year load growth change % without conservation	5-year load growth change % met by conservation	10-year load growth change % met by conservation
Kalispel Tribal Utilities	25.31%	32.70%	0.00%	0.00%
Kittitas County PUD No. 1	10.87%	21.01%	2.00%	1.03%
Klickitat County PUD No. 1	-3.44%	3.23%	0.00%	0.00%
Lakeview Light & Power	1.83%	2.86%	21.82%	13.95%
Lewis County PUD No. 1	2.93%	8.07%	0.00%	0.00%
Mason County PUD No. 1	2.26%	4.20%	0.00%	0.00%
Mason County PUD No. 3	7.82%	16.30%	21.08%	10.42%
McCleary, City of	4.47%	5.83%	0.00%	0.00%
Milton, City of	-0.06%	0.16%	-775.00%	281.82%
Modern Electric	-0.20%	2.14%	-126.68%	11.88%
Nespelem Valley Electric Coomprative	4.99%	7.09%	0.00%	0.00%
Ohop Mutual Light Company	3.22%	7.95%	14.03%	5.68%
Okanogan County Electric Cooperative	9.41%	16.15%	0.00%	0.00%
Okanogan County PUD No. 1	4.73%	8.45%	0.00%	0.00%
Orcas Power and Light Cooperative	6.34%	8.82%	0.00%	0.00%
Pacific County PUD No. 2	2.75%	5.23%	50.00%	21.05%
PacifiCorp	9.82%	15.91%	72.64%	80.89%
Parkland Light and Water Company	1.42%	2.39%	10.47%	6.23%
Pend Oreille PUD	-58.45%	-56.90%	0.00%	0.00%
Peninsula Light	-4.67%	-4.14%	-14.62%	-16.50%
Port Angeles, City of	5.02%	6.70%	28.51%	43.42%
Puget Sound Energy	1.68%	4.61%	369.23%	363.55%
Richland, City of	11.05%	16.16%	26.78%	66.31%
Seattle City Light	8.62%	19.37%	52.69%	44.02%
Seattle, Port of	2.53%	23.11%	31.90%	3.50%
Skamania County PUD No. 1	5.62%	9.05%	1.05%	0.65%
Snohomish County PUD No. 1	9.56%	25.45%	42.27%	40.96%
Steilacoom, Town of	4.75%	7.01%	5.71%	3.87%
Sumas, City of	4.85%	4.85%	11.11%	11.11%
Tacoma Power	-2.78%	1.99%	-154.95%	478.49%
Tanner Electric	18.69%	21.78%	0.89%	0.77%
Vera Water and Power	3.52%	7.02%	4.93%	2.47%
Wahkiakum County PUD No. 1	8.10%	11.96%	0.00%	0.00%
Whatcom County PUD No. 1	10.51%	47.71%	0.00%	0.00%

Utility Name	5-year load growth change % without conservation	10-year load growth change % without conservation	5-year load growth change % met by conservation	10-year load growth change % met by conservation
Yakama Power	4.71%	6.01%	5.88%	4.61%
Average	**8.47%**	**15.46%**	**-4.07%**	**30.59%**

Energy efficiency and conservation (also referred to as energy conservation measures) is a fundamental resource for utilities in their long-term planning, but utilities are anticipating energy efficiency and conservation to contribute less towards meeting load growth. Projected load growth across utilities is also greater than prior resource plans due to the incorporation of new load growth projections due to building and transportation electrification. For instance, Avista anticipates that energy conservation measures will meet a significant portion of future load growth, although the percentage may be lower than in previous forecasts due to factors like electric transportation, building electrification, and market saturation of efficient technologies. Energy conservation measures meet more than 27% of all future load growth for Avista, where prior IRP forecasts found energy conservation measures met nearly 70% of future load growth.[21]

Several utilities are actively exploring and implementing demand response programs, specifically targeting large load customers, including data centers and cryptocurrency miners, to manage peak demand. For instance, Grant PUD is currently operating a pilot demand response program aimed at high load factor customers, including cryptocurrency miners. They are also considering direct load curtailment for irrigation customers. Grant PUD anticipates these programs can help reduce near-term capacity shortfalls and compete with storage and peaking assets. They estimate 30 to 50 MW could be available through these DR programs by 2026.[22] Tacoma Power is testing demand response as a potential resource option under scenarios where they anticipate capacity shortfalls. They have considered generic demand response resources that either shift usage or are called upon during peak events, equivalent to approximately 20 to 30 MW by the late 2030s.[23] In 2024, Clark Public Utilities (CPU) launched an industrial demand response incentive pilot program allowing qualified customers to nominate load reductions during a demand response event. CPU plans to continue expanding demand response programs as they become more cost-effective and with the adoption of Advanced Metering Infrastructure (AMI). [24]

Overgeneration

In 2013, the Legislature amended the resource planning statute to address concerns about the potential for "overgeneration" events.[25] The legislation required that utilities consider this potential in their planning "if applicable to the utility's resource portfolio," and required that Commerce include in this report an assessment of utility approaches to overgeneration.

The statute defines an overgeneration event as:

[21] Avista. (2023, Chapter 9, p. 7). Electric Integrated Resource Plan.
[22] Grant PUD. (2024, p. 77). Integrated Resource Plan.
[23] Tacoma Power. (2024, p. 39-40). Integrated Resource Plan.
[24] Clark Public Utilities. (2024, p. 74). Integrated Resource Plan.
[25] Section 19.280.060 Department's duties—Report to the legislature. (2025). Retrieved from Revised Code of Washington.

> An event within an operating period of a balancing authority when the electricity supply, including generation from intermittent renewable resources, exceeds the demand for electricity for that utility's energy delivery obligations and when there is a negatively priced regional market.

Overgeneration is also referred to as oversupply. It might occur when high river flows and high wind volumes coincide with low load. It might also occur when the hours of solar generation misalign with peak electricity demand. The capacity of the hydroelectric system to store extra river flow is limited, and even the option of spilling water over the dams is restricted by fish mortality concerns. In these circumstances, the regional power system may have more electric generation from hydroelectric, wind, and solar resources than what is required to meet regional loads and export opportunities. This oversupply results in negatively priced spot market prices. The consequence is that a utility must pay another entity to take unwanted power or generation is curtailed. Many wind generators receive federal incentive credits and/or payments based upon their wind production, and they can sell the RECs from this generation. Thus, these generators can withstand some degree of negative pricing and still make a profit.[26]

Since 2013, the Bonneville Power Administration has adopted an Oversupply Management Protocol, providing tools for the operators of the hydroelectric system and transmission grid to manage oversupply situations.[27] In the Northwest, the BPA has business practices that push the burden of oversupply back to the market and away from themselves. These practices include not selling at negative prices until spilled water reaches dissolved gas limits, holding renewable generators to a fixed schedule, not accepting unplanned surplus, and canceling transmission loss returns.[28] The implementation of this protocol has generally shifted the overgeneration issue from a planning concern to an operational concern.

In many cases, utilities did not find it necessary in their 2022-2024 resource plans to address overgeneration, or generation curtailment, as an issue separate from the more general assessment of generating resource alternatives.

Resource adequacy

Most utilities plan to meet load requirements in the lowest-cost, least-risk way by renewing BPA contracts (for slice or block products or shifting to a load following product), maximizing energy conservation measures, and implementing new demand and response programs.

Many consumer-owned utilities already have 80% or more renewable generation, and they plan to comply with CETA requirements between 2030 and 2045 using clean energy credits. With the emergence of the Western Resource Adequacy Program (WRAP) and increased reliance on regional markets for power, some utilities, such as Snohomish PUD and Benton PUD, are moving to BPA load-following customers to rely on BPA to ensure resource adequacy.

Other strategies utilities reported considering include:

- Developing WRAP
- Investigating dispatchable, renewable and non-emitting resources, such as batteries, hydrogen, geothermal and small modular nuclear reactors
- Diversifying the geographic location of their renewable resources

[26] Chelan PUD. (2023, p. 24-25). Integrated Resource Plan Progress Report.
[27] Oversupply. (n.d.). Retrieved from Bonneville Power Administration.
[28] Chelan PUD. (2023, p. 25). Integrated Resource Plan Progress Report.

- Enhancing the capacity of their transmission lines

Regional resource adequacy forecasts

Commerce and the Utilities and Transportation Commission (UTC) regularly review regional resource adequacy assessments and other load forecasts and scenario studies,[29] and convene an annual meeting with regional resource adequacy experts, utilities, and other stakeholders per RCW 19.280.065.

The joint meeting between the UTC and Commerce in September 2024 found assessments of resource adequacy from regional experts show the Northwest has adequate resources to meet current demand for electricity and does not face a significant risk of outages in the near term.[30] However, these assessments assume the industry will be able to execute their planned capacity expansions. Confidence in these assessments is also limited by the increasing level of uncertainty that planners face about future demand for electricity. The sources of this uncertainty include the added volatility of our weather, the pace of consumer conversion to electricity for transportation, heating and other end uses, and the growing energy demands of data centers. Common themes across resource adequacy assessments and other regional load forecasts and scenario studies include:

- Participation of utilities in WRAP is crucial for the future of regional resource adequacy
- Limited transmission capacity is a key binding constraint that once addressed would enable utilities to more efficiently access a diverse set of cost-effective resources from across the West, mitigate weather disruptions, and enhance regional resource adequacy
- Demand-side management and virtual power plants have significant potential to shave peak load and maintain resource adequacy
- Traditional battery storage technologies can help enable the smooth integration of intermittent renewables onto the electric grid while emerging long duration storage technologies can support the electric grid for multiple days during potential natural gas supply or electric generation disruptions
- Emerging technologies, such as green hydrogen and enhanced geothermal, show promise as firm power supplies free of greenhouse gas emissions
- High data center load growth and lower than expected energy efficiency scenarios would place severe resource demands on the grid and put the adequacy of the electric grid at risk
- The region needs to steadfastly permit, site, and build resources to maintain current levels of resource adequacy over the medium-to-long term

Conclusion

The 2024 Washington State Electric Utility Resource Planning report reveals modest load growth increasingly met by clean energy resources. Utilities plan to cut coal and market purchases, and increase use of hydropower, wind, and solar.

After years of declining or stagnant load forecasts, utilities across the state project modest load growth from population increases and electrification. Alongside this general assessment, substantial load growth was forecasted by Grant, Douglas, Chelan PUDs, driven by potential data center electricity needs.

To meet these demands, consumer-owned utilities are focusing on renewing their Bonneville Power Administration (BPA) contracts, and both consumer-owned utilities and investor-owned utilities are developing new renewables

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[29] These studies include but are not limited to: the Western Electricity Coordinating Council Resource Assessment of Resource Adequacy, the Pacific Northwest Power and Conservation Council Power Supply and Adequacy Assessment; and Pacific Northwest Utilities Conference Committee Northwest Regional Forecast, the latter of which is not a resource adequacy assessment.

[30] 2024 Resource Adequacy Letter and Summary; Western Assessment of Resource Adequacy 2024.

and maximizing conservation. While many consumer-owned utilities plan to phase out natural gas, investor-owned utilities project stable usage. Wind power is notably forecasted to surpass natural gas within ten years, advancing Clean Energy Transformation Act (CETA) goals. Some utilities are preparing for dual winter and summer peaks due to increased summer temperatures and household cooling demands driven by climate change. Regional assessments indicate adequate resources to meet loads in the near term, but maintaining resource adequacy depends on successful capacity expansions and increased regional cooperation between utilities.

The 2024 report presents several other developments since the 2022 legislative report:

- Incorporation of climate change and electrification modelling: The resource plans summarized in the 2024 report more thoroughly accounted for the impacts of climate change and electrification. These changes resulted in a shift in peak demand for some utilities and modest load growth for many utilities.
- Energy conservation contribution: The 2024 report offers a more cautious outlook on the incremental contribution of energy conservation measures (ECM) to meet future load growth compared to 2022. Planned five-year ECM is 70 aMW lower than the 2022 report's anticipation for that period.
- Reduced market reliance for peak demand: The 2024 report indicates utilities have a stronger intent to reduce reliance on short-term wholesale market purchases for peak demand, a shift from earlier forecasts where such purchases were more prominent in peak capacity strategies.
- Load resource balance: The 2024 report projects a tighter (lower) load-resource balance (surplus) for base, five-year, and ten-year forecasts compared to 2022's anticipated balances, suggesting a closer but adequate margin between expected resources and requirements.

Finally, this report points to a continued need to improve clean energy siting and permitting processes and enhance transmission capacity in Washington and across the Western Interconnection. Increased deployment of demand-side management, virtual power plants, and traditional battery storage systems, accompanied by emerging technologies and utility participation in the Western Regional Adequacy Program (WRAP), are additional actions that would further resource adequacy and the clean energy transition.

Appendix A: Utility cover sheets

Washington Electric Utility Loads and Resources Estimates reported to the Department of Commerce in 2024 are available in this Excel workbook.

Appendix B: Washington utility customer count, revenue, sales, and average price[31]

Behind the Meter	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Tesla Inc.	99	$67	608	11¢
Sunnova	60	$11	64	17¢

Cooperative	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Inland Power & Light Company	44,400	$85,033	1,016,225	8¢
Peninsula Light Company	35,429	$60,993	624,171	10¢
Elmhurst Mutual Power & Light Co	16,037	$21,137	279,846	8¢
Benton Rural Electric Assn	15,962	$44,938	620,972	7¢
Orcas Power & Light Coop	15,855	$36,214	214,371	17¢
Modern Electric Water Company	10,615	$15,619	227,881	7¢
Lakeview Light & Power	10,481	$23,781	251,778	9¢
Big Bend Electric Coop, Inc	9,946	$42,454	564,937	8¢
Columbia Rural Elec Assn, Inc	6,490	$33,210	367,976	9¢
Tanner Electric Coop	5,317	$12,949	99,247	13¢
Ohop Mutual Light Company, Inc	5,017	$8,438	98,989	9¢
Parkland Light & Water Company	4,591	$9,005	117,676	8¢
Okanogan County Elec Coop, Inc	4,143	$6,798	67,139	10¢
Yakama Power	2,298	$7,004	95,343	7¢
Nespelem Valley Elec Coop, Inc	1,538	$5,535	59,863	9¢
Clearwater Power Company	1,046	$2,326	21,443	11¢
Kootenai Electric Cooperative	98	$267	2,626	10¢
Northern Lights, Inc	15	$30	252	12¢

[31] Energy Information Administration. (2023). Annual Electric Power Information Report.

Federal	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Bonneville Power Administration	10	$31,985	1,195,413	3¢

Investor owned	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Puget Sound Energy Inc	1,223,225	$2,753,519	23,436,236	12¢
Avista Corp	270,433	$610,155	5,739,294	11¢
PacifiCorp	136,363	$387,829	3,850,048	10¢

Municipal	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
City of Seattle - (WA)	503,221	$1,048,523	9,228,431	11¢
City of Tacoma - (WA)	196,833	$410,927	4,552,573	9¢
City of Richland - (WA)	27,048	$77,437	997,726	8¢
City of Port Angeles - (WA)	11,018	$27,557	396,839	7¢
City of Centralia - (WA)	10,701	$26,675	265,359	10¢
City of Ellensburg - (WA)	10,582	$19,101	221,650	9¢
City of Cheney - (WA)	6,007	$8,359	148,111	6¢
Town of Steilacoom	3,782	$4,335	38,733	11¢
City of Blaine - (WA)	3,766	$7,244	83,974	9¢
City of Milton - (WA)	3,593	$5,964	55,110	11¢
City of Chewelah	1,363	$2,115	24,088	9¢
Town of Eatonville - (WA)	1,278	$2,302	28,247	8¢
City of McCleary - (WA)	1,194	$3,752	31,649	12¢
City of Sumas - (WA)	1,028	$2,582	31,283	8¢
Town of Ruston - (WA)	622	$1,368	10,382	13¢
City of Coulee Dam - (WA)	602	$1,243	16,701	7¢
PUD No 1 of Asotin County	3	$14	245	6¢

Political subdivision	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
PUD No 1 of Snohomish County	377,261	$668,410	6,794,876	10¢
PUD No 1 of Clark County - (WA)	235,481	$392,180	4,785,718	8¢
PUD No 1 of Benton County	57,263	$134,664	1,838,441	7¢
PUD No 2 of Grant County	55,012	$269,355	5,958,946	5¢
PUD No 1 of Cowlitz County	53,155	$232,091	4,104,045	6¢
PUD No 1 of Chelan County	49,579	$67,197	1,876,426	4¢
PUD No 1 of Grays Harbor County	45,223	$106,199	930,270	11¢
PUD No 3 of Mason County	35,985	$80,923	695,379	12¢
PUD No 1 of Lewis County	34,809	$81,808	964,301	8¢
PUD No 1 of Clallam County	33,931	$72,147	665,293	11¢
PUD No 1 of Franklin County	29,428	$87,670	1,103,231	8¢
PUD No 1 of Okanogan County	22,018	$53,592	633,607	8¢
PUD No 1 of Jefferson County	20,873	$42,250	391,951	11¢
PUD No 2 of Pacific County	18,338	$27,693	315,430	9¢
PUD No 1 of Douglas County	17,364	$53,512	1,345,707	4¢
PUD No 1 of Klickitat County	14,111	$38,965	441,885	9¢
Vera Irrigation District #15	13,509	$20,325	239,014	9¢
PUD No 1 of Pend Oreille County	10,008	$53,256	695,193	8¢
PUD No 1 of Skamania Co	6,571	$15,873	137,082	12¢
PUD No 1 of Mason County	5,610	$10,251	83,748	12¢
PUD No 1 of Ferry County	3,783	$7,784	80,287	10¢
PUD No 1 of Kittitas County	3,771	$12,800	112,794	11¢
PUD No 1 of Wahkiakum County	2,776	$4,638	46,164	10¢
PUD No 1 of Whatcom County	1	$10,206	229,343	4¢

Retail power marketer	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Shell Energy North America (US), L.P.	3	$33,821	486,097	7¢
BP Energy Company	2	$82,247	830,991	10¢
Brookfield Renewable Energy Marketing US LLC	1	$19,697	361,074	5¢
Avangrid Renewables	1	$1,019	32,879	3¢
Calpine Energy Solutions, LLC	1	$970	8,012	12¢

Appendix C: Glossary of terms

Average annual energy: one megawatt is equal to one million watts. One million watts delivered continuously 24 hours a day for a year (8,760 hours) is called an average megawatt. The maximum amount of power a generating plant is capable of producing over the course of an average year is called its generating capability or average annual energy, expressed in average megawatts.

Behind-the-meter (BTM) solar: refers to customer-sited solar energy panels. BTM solar includes the expected generating capability that is customer-owned, utility-owned, and third-party owned.

Cogeneration: the sequential production of electricity and useful thermal energy from a common fuel source.

Demand response: the voluntary and temporary reduction in consumers' use of electricity when the power system is stressed. It includes voluntary demand response, demand response with paid incentives, time-of-use, and demand voltage reduction programs.

Distributed generation: an eligible renewable resource where the facility or any integrated cluster of generating units has a generating capacity of not more than five megawatts.

Duration value at risk (VaR Duration): longest shortfall event for the 97.5th worst simulation year. VaR Duration sets a limit for shortfall duration during rare (once per 40 year) events. To calculate this metric, the duration of the longest shortfall event for each simulation year is recorded (or zero if there is no shortfall). The Duration VaR97.5 is the 97.5th highest duration from that record. Choosing the 97.5th percentile limits the risk of an excessively long shortfall event to no more than once per 40 years.

Energy conservation measures (also referred to as conservation and efficiency resources): any reduction in electric power consumption resulting from increases in the efficiency of energy use, production, or distribution.

Energy value at risk (VaR energy): total annual shortfall energy for the 97.5th worst simulation year. VaR Energy set limits for the big energy shortfalls during rare (once per 40 year) events.

Front-of-the-meter (FTM) distributed solar: refers to solar power that is located on the distribution system or any subsystem of the distribution system.

Loss of load probability (LOLP): traditionally, a power supply is deemed to be adequate when its annual Loss of Load Probability (LOLP) is 5% or less; that is, when the likelihood of having one or more shortfalls during an operating year is less than or equal to 5%. A 5% LOLP means that the simulated operation of the power supply yields only one year out of 20 with shortfalls.

Loss of load events (LOLEV): the expected number of shortfall events per year. A shortfall event is a set of contiguous hours of unserved demand. LOLEV is equal to the total number of shortfall events divided by the total number of simulation years.

Net short-term contracts/market purchases: refers to limited duration wholesale power purchase not to exceed one month, made by an electric utility for delivery to Washington retail electric customers for which the source of the power is not known at the time of entry into the transaction to procure the electricity.

Loads: electric loads include retail sales + line losses + utility needs. The base year includes existing conservation or demand reduction as a part of base year load. All projected electric loads (non-base year) are estimated before reductions from energy conservation measure programs or demand response program estimates. Additional future conservation and demand response are treated as resources to meet future load.

Peak energy: highest estimated one-hour load for summer and winter, normalized for weather.

Peak Value at Risk (VaR Peak): highest single-hour shortfall for the 97.5th worst simulation year. VaR Peak set limits for occurrences of big energy shortfalls during rare (once per 40 year) events.

Resource adequacy: the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components.

Renewable resources: RCW 19-280, Electricity Utility Resource Plans, defines "renewable resources" as "electricity generation facilities fueled by: (a) Water; (b) wind; c) solar energy, (d) geothermal energy, (e) landfill gas, (f) biomass energy utilizing animal waste, solid organic fuels from wood, forest or field residues or dedicated energy crops that do not include wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic; (g) by-products of pulping or wood manufacturing processes, including but not limited to bark, wood chips, sawdust, and lignin in spent pulping liquors; (h) ocean thermal, wave or tidal power; and (i) gas from sewage treatment facilities."

Utility-scale solar: refers to a large-scale solar power project that is interconnected to the transmission system.

Western Electricity Coordinating Council (WECC): WECC promotes bulk power system reliability and security in the Western Interconnection. WECC is the regional entity responsible for compliance monitoring and enforcement and oversees reliability planning and assessments. In addition, WECC provides an environment for the development of reliability standards and the coordination of the operating and planning activities of its members.

Western interconnection: the geographic area containing the synchronously operated electric grid in the western part of North America, which includes parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming and Mexico and all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington and the Canadian provinces of British Columbia and Alberta.

Western Resource Adequacy Program (WRAP): The Western Resource Adequacy Program (WRAP) is the first regional reliability planning and compliance program in the history of the West.

It will deliver a region-wide approach for assessing and addressing resource adequacy and provide an important step forward for reliability in the region.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-27:
NERC 2025 Summer Reliability Assessment

2025 Summer Reliability Assessment

May 2025

Table of Contents

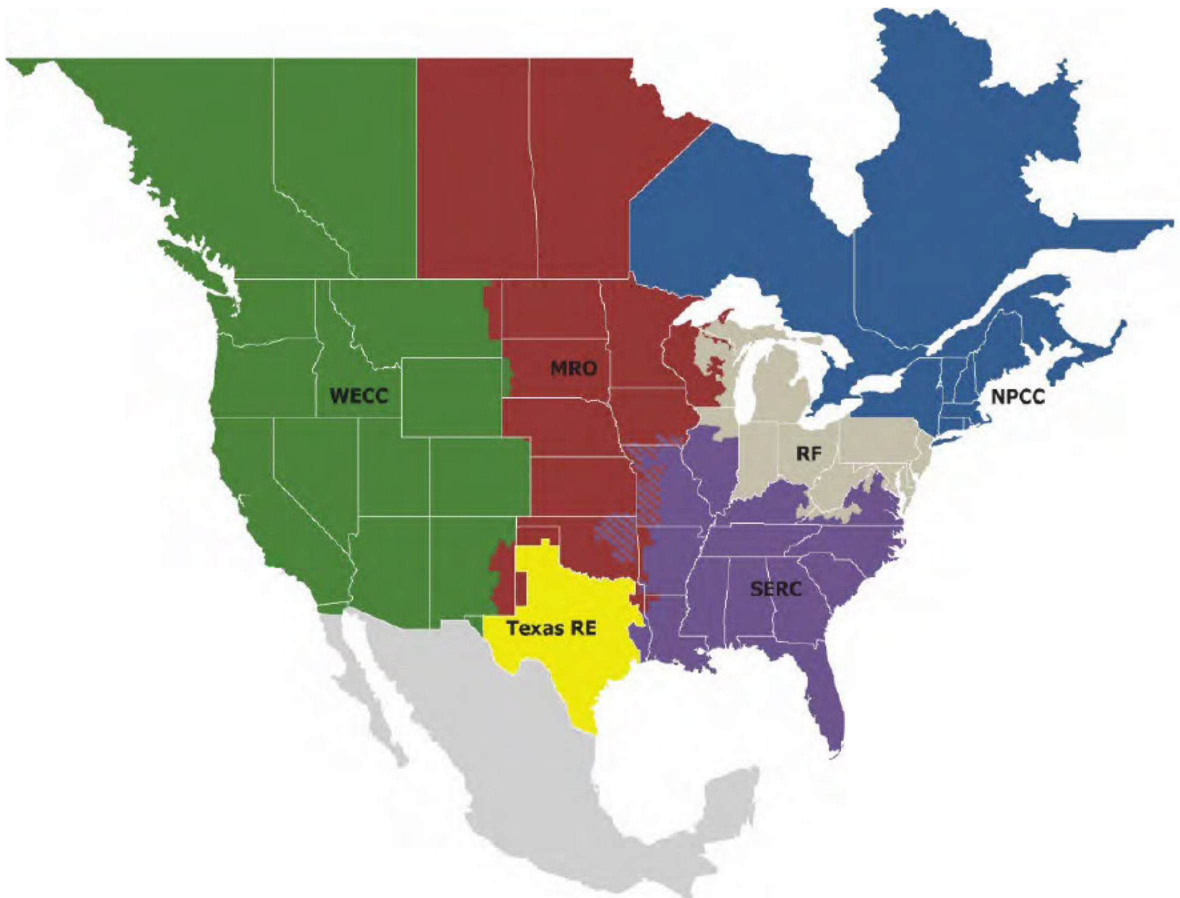
Preface

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

Reliability | Resilience | Security

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

The North American BPS is spans six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



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

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA*), which covers a 10-year horizon*,* and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

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

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

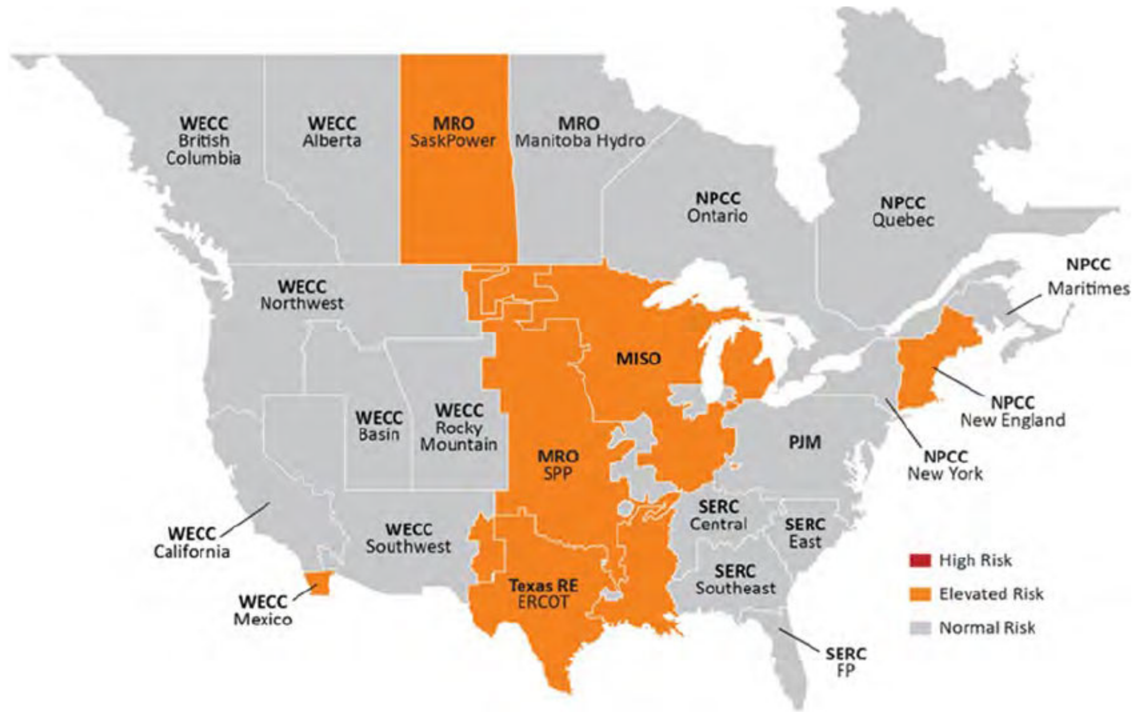


Figure 1: Summer Reliability Risk Area Summary

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

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA.* Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's 2024 *State of Reliability* report

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

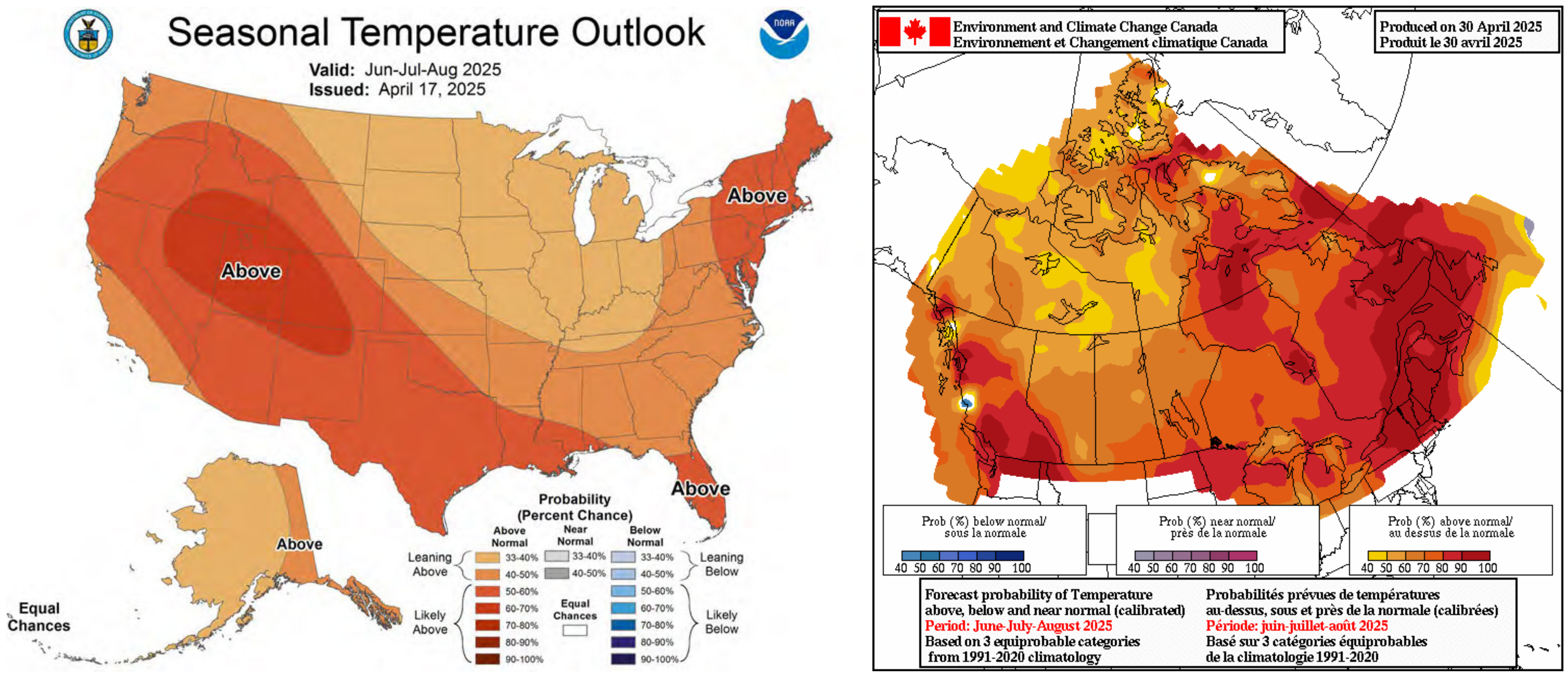


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

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

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

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

Assessment of Planning Reserve Margins and Operational Risk Analysis

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

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

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

The seasonal risk scenario charts can be expressed in terms of reserve margins: In Table 2, each assessment area's 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.

Highlighted in orange are the areas identified as having resource adequacy or energy risks for the summer in the Key Findings section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the 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.

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

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels		
EEA Level	**Description**	**Circumstances**
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	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.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

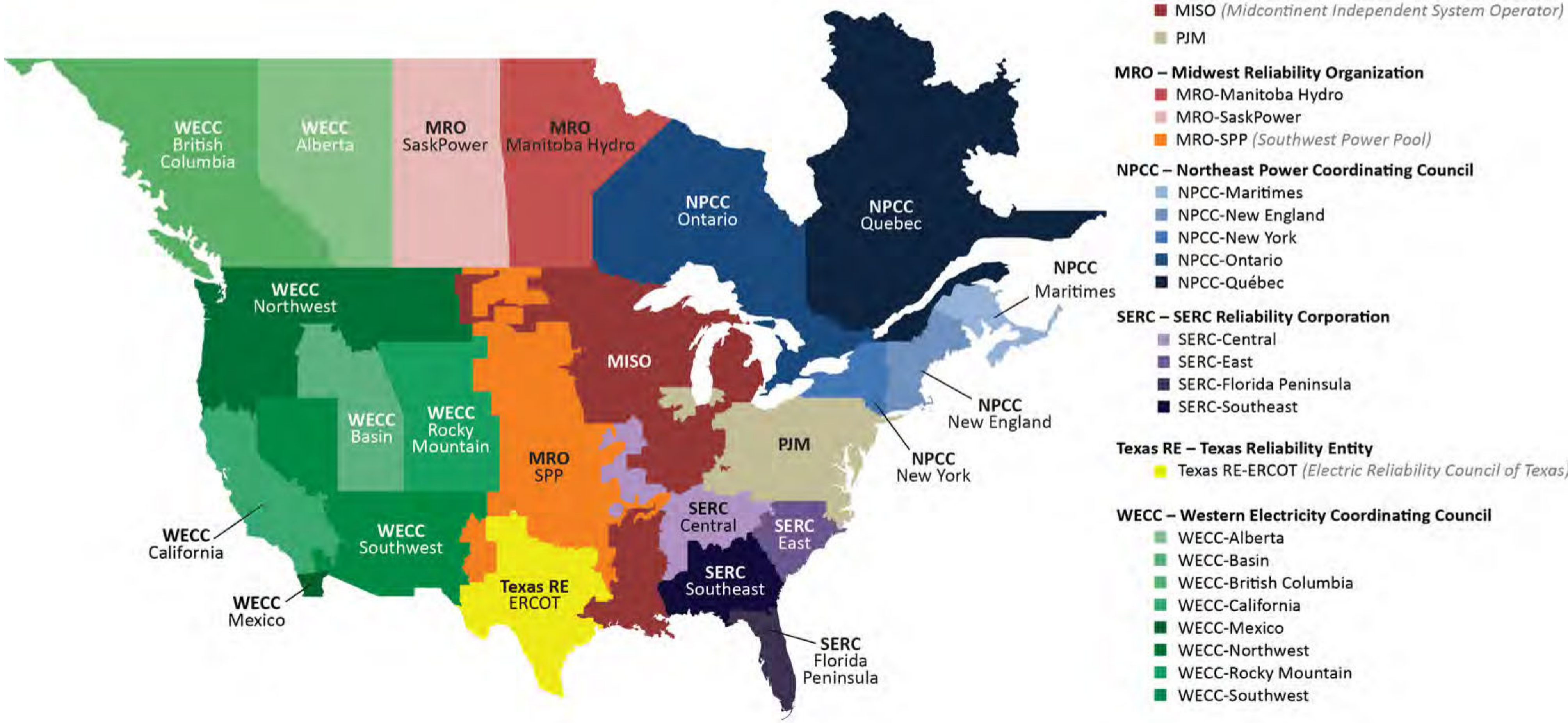
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central SERC-East SERC-Florida Peninsula SERC-Southeast	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer 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 *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

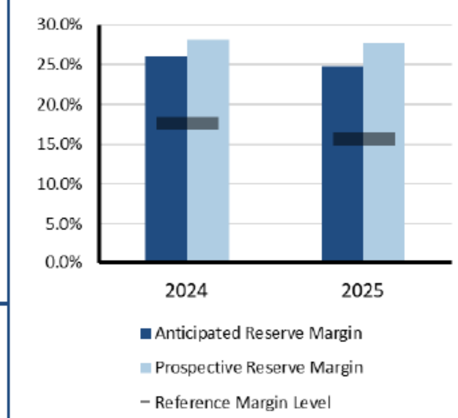
Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

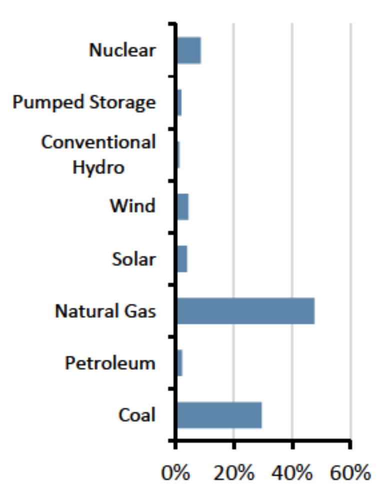
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

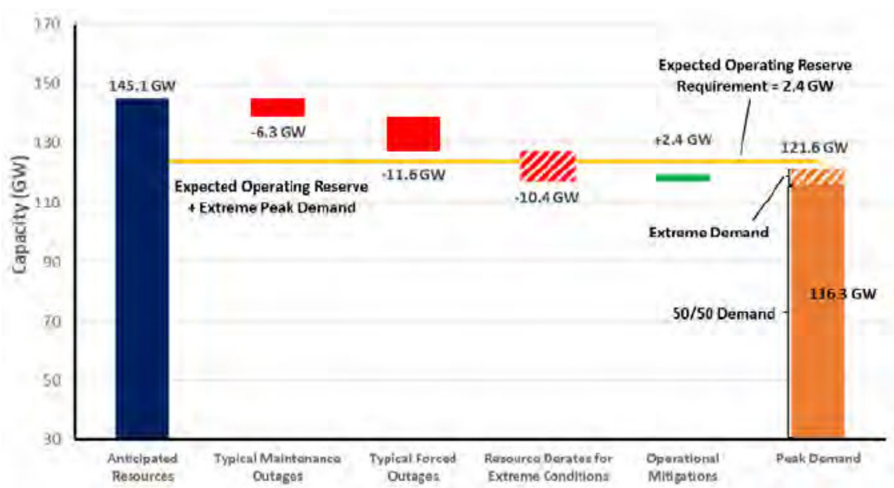
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer 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 summer average of maintenance and planned outages

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

Extreme Derates: Maximum historical generation outages

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

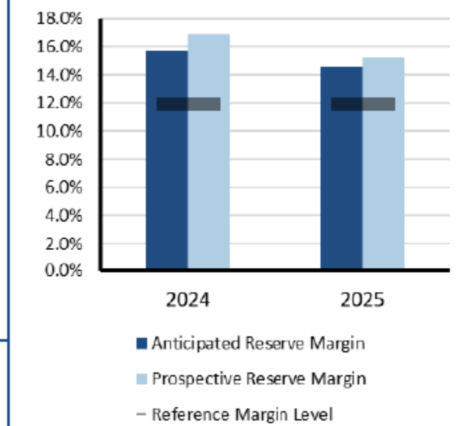
MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

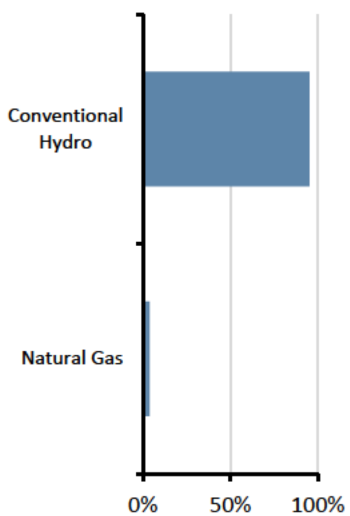
On-Peak Reserve Margin



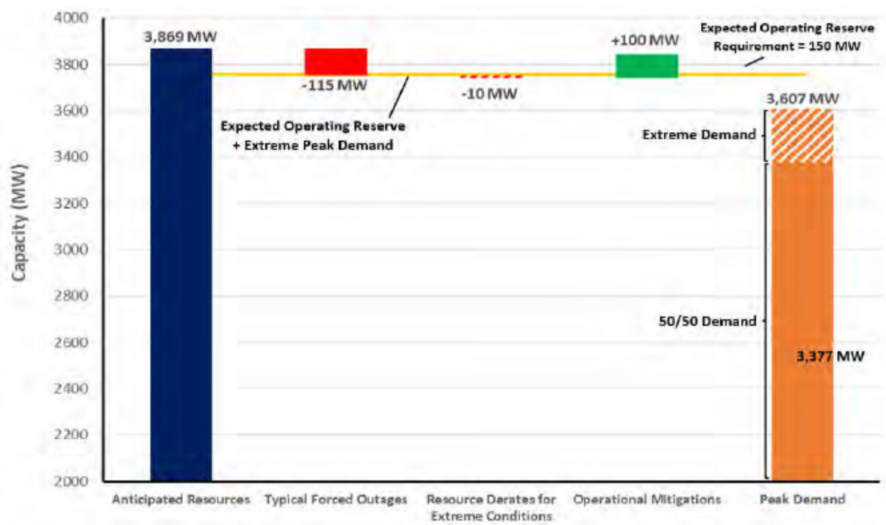
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

MRO-SaskPower

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

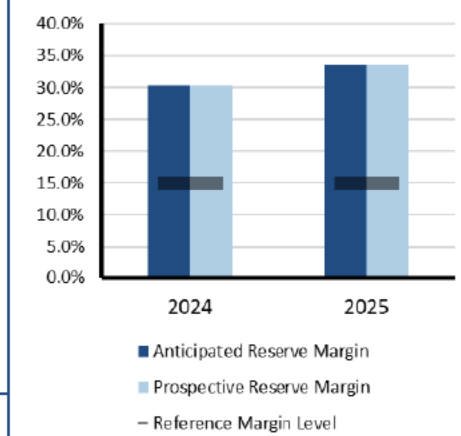
Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

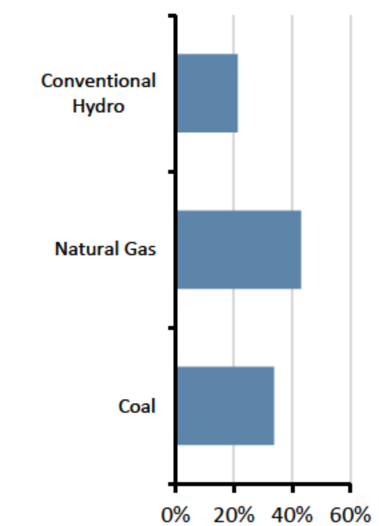
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

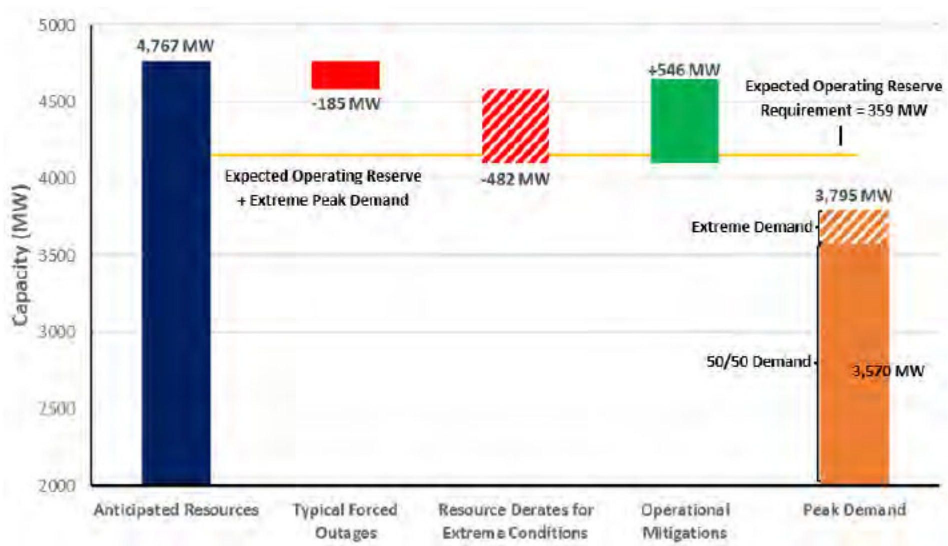
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer 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

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice

MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

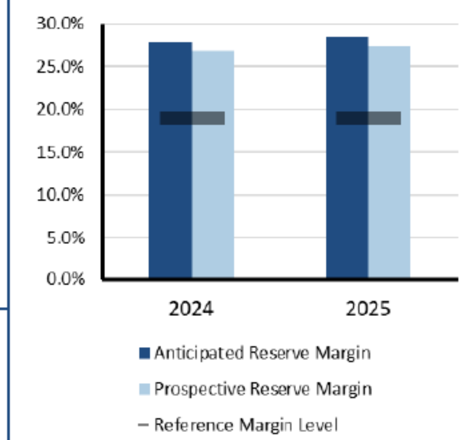
Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

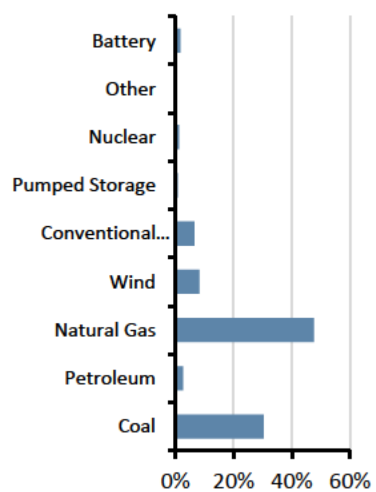
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

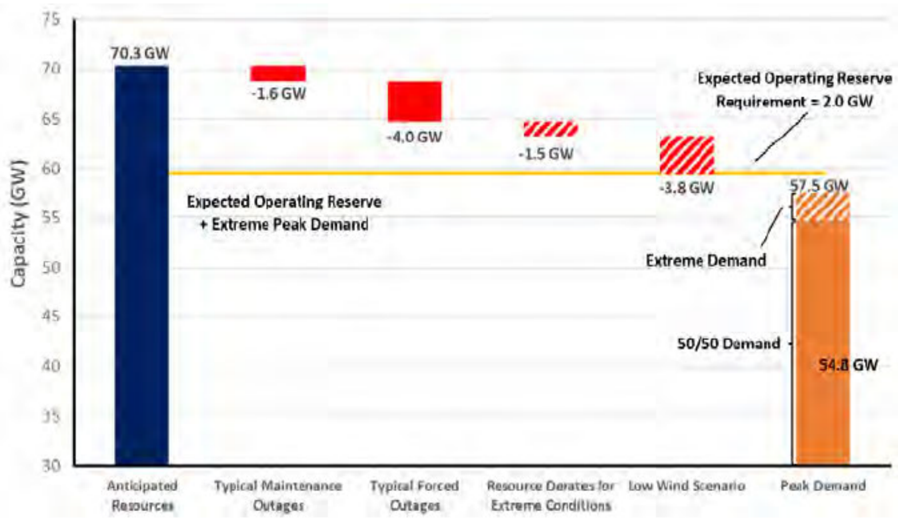
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer 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 is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

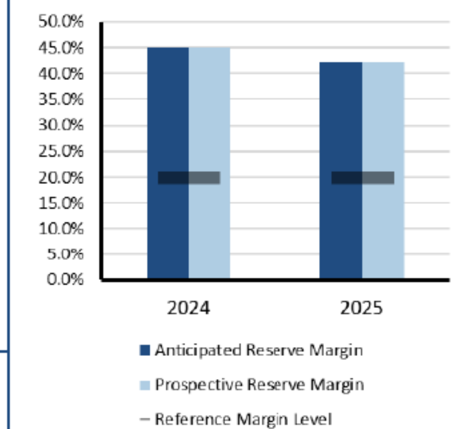
NPCC-Maritimes

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

Highlights

- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

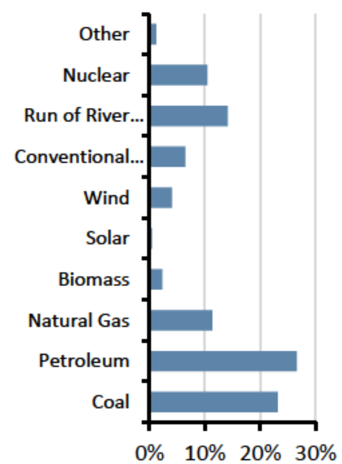
On-Peak Reserve Margin



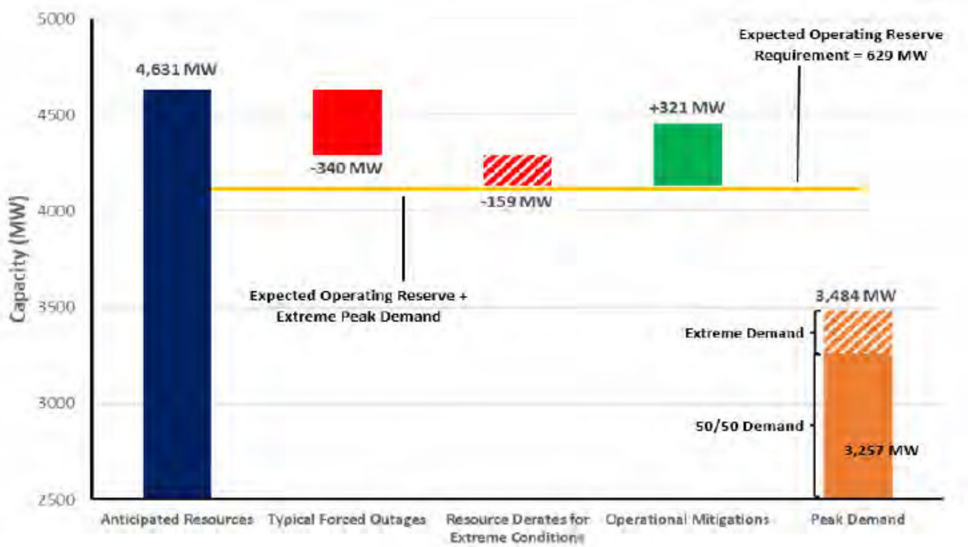
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer 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 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)

NPCC-New England

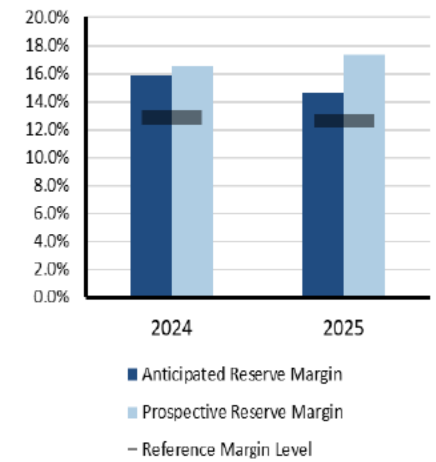
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

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

Highlights

- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

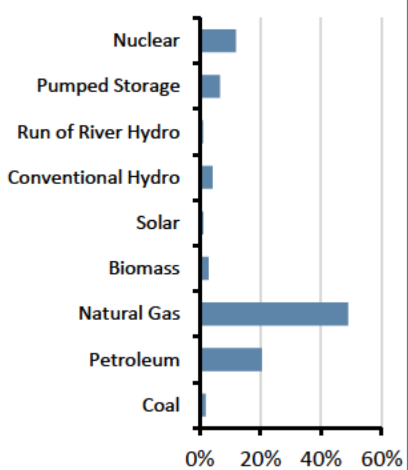
On-Peak Reserve Margin



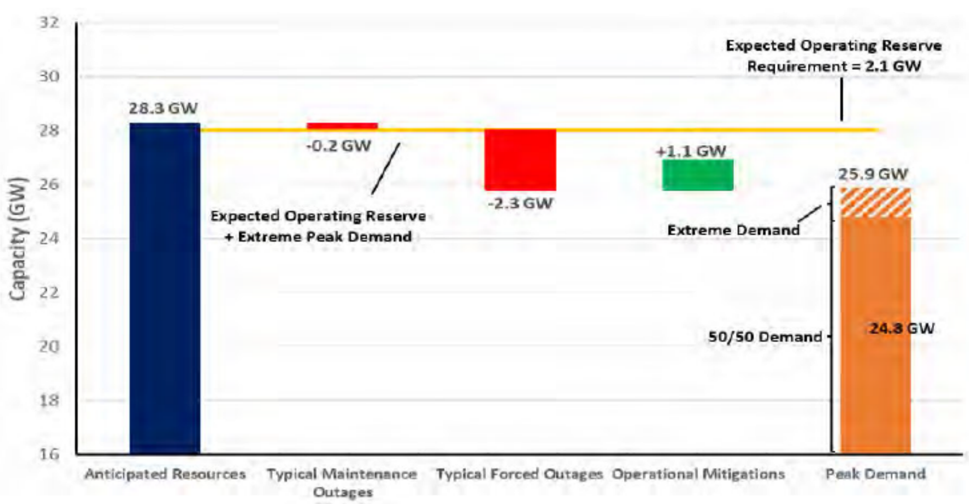
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

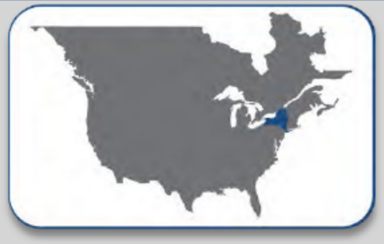
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

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

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



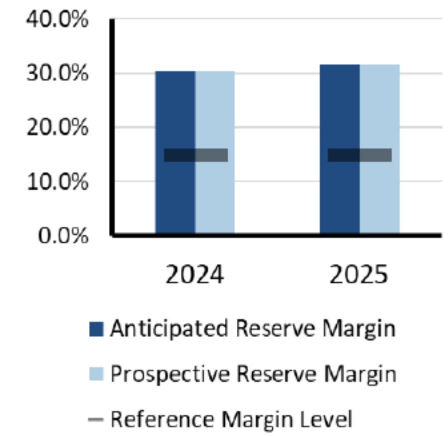
NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

Highlights

- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

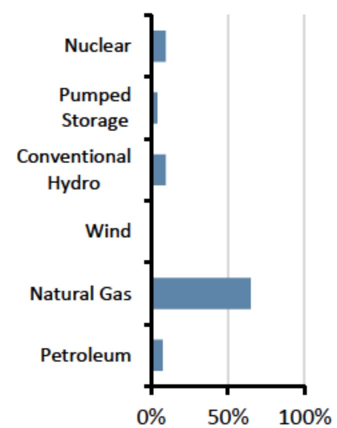
On-Peak Reserve Margin



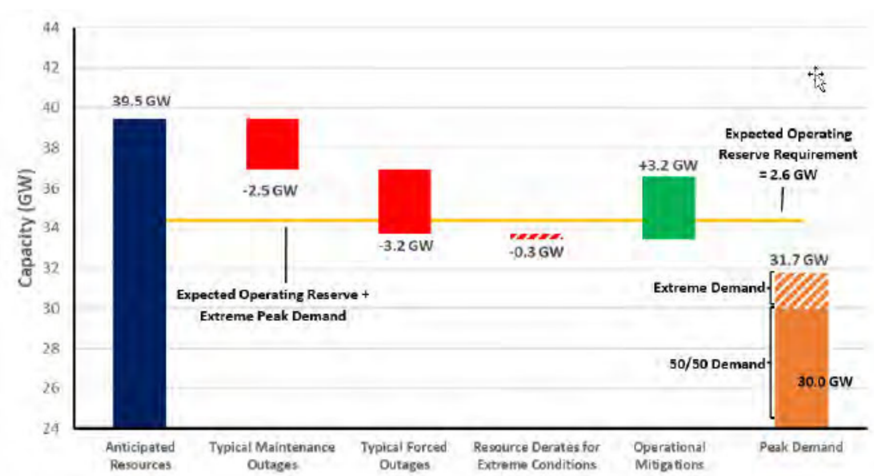
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Fuel Mix



2025 Summer 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) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual

NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

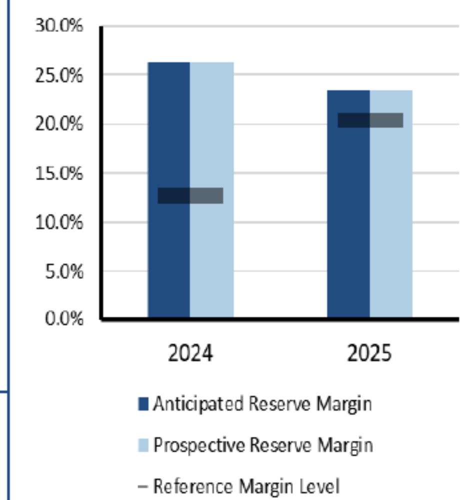
Highlights

- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

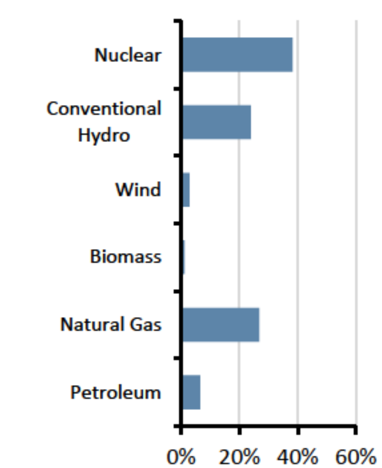
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

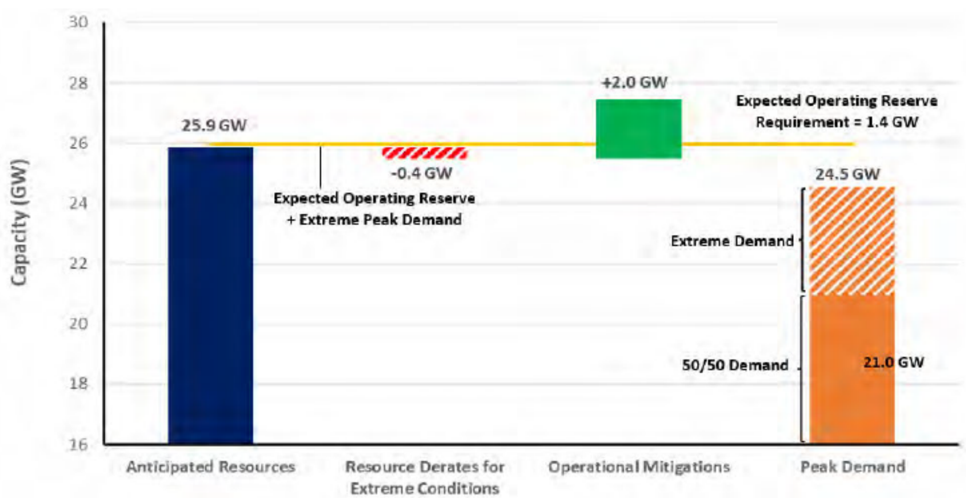
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer 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 based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.

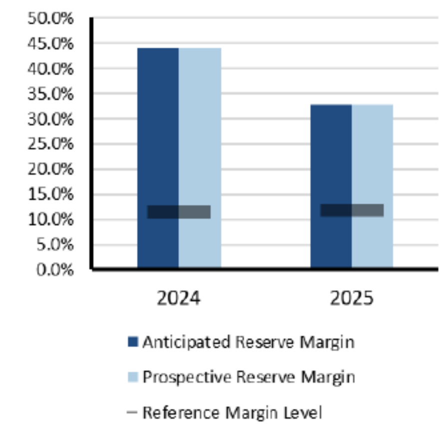
NPCC-Québec

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 high-voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

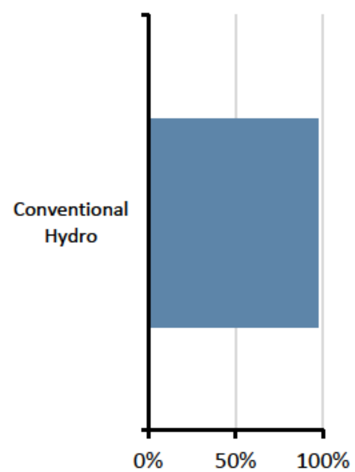
On-Peak Reserve Margin



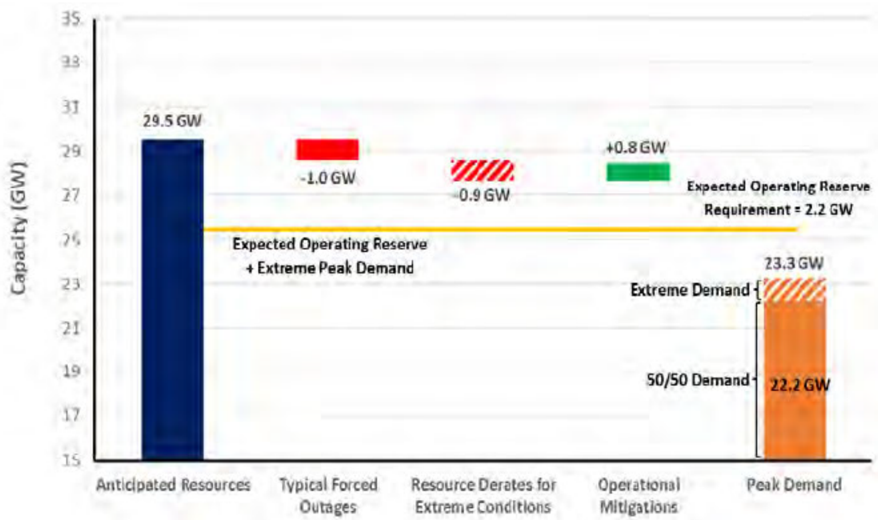
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.

PJM

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

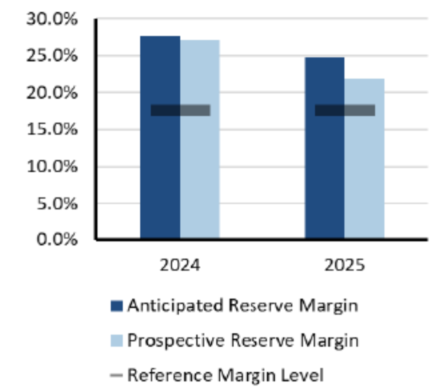
Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

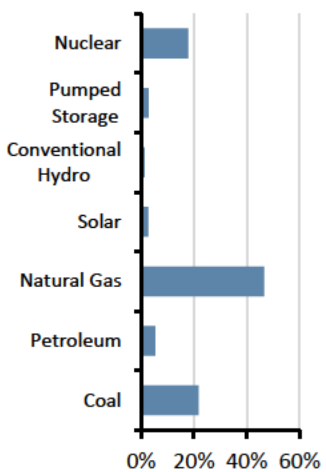
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

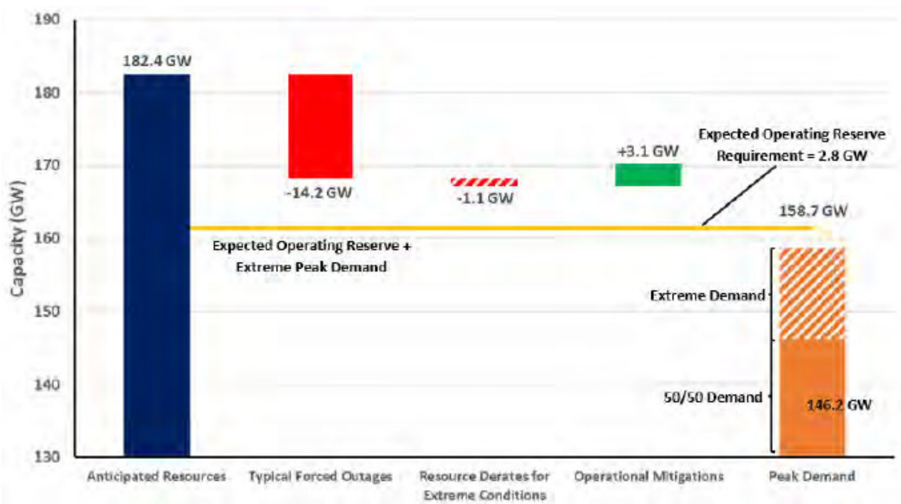
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Based on historical data and trending

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

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

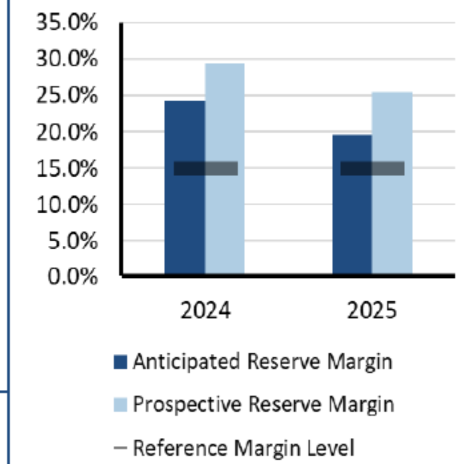
SERC-Central

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

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

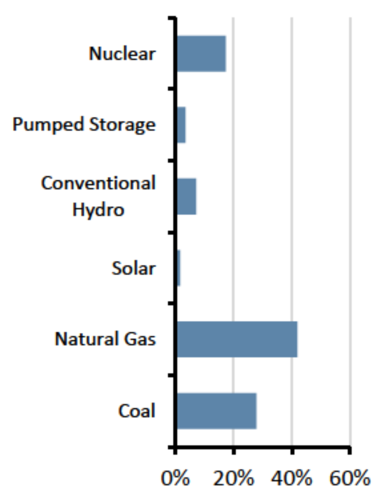
On-Peak Reserve Margin



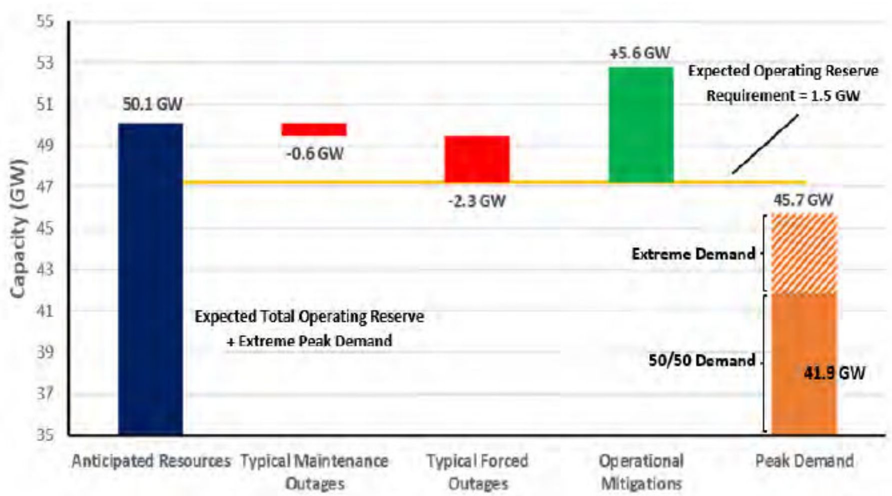
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures

SERC-East

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

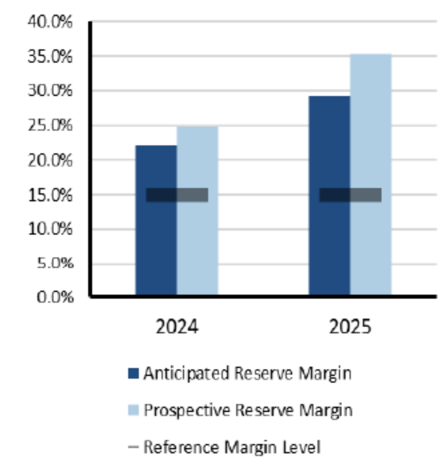
Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

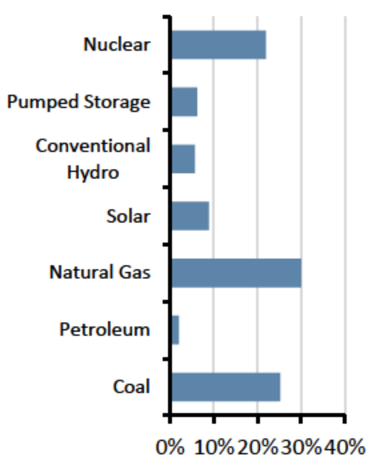
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures

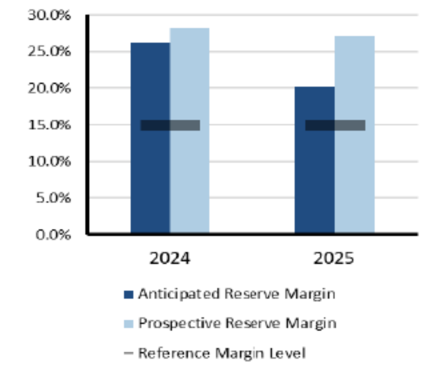
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

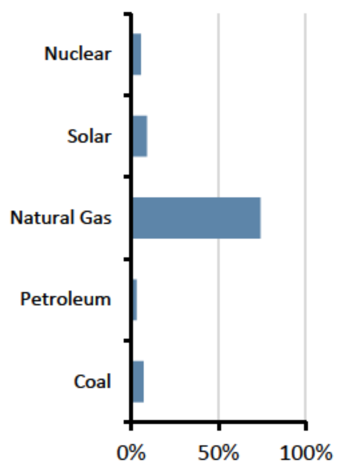
On-Peak Reserve Margin



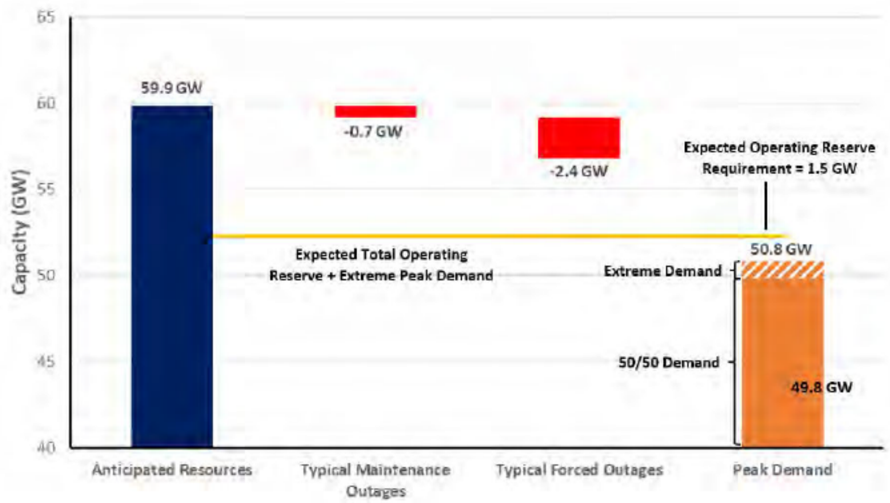
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

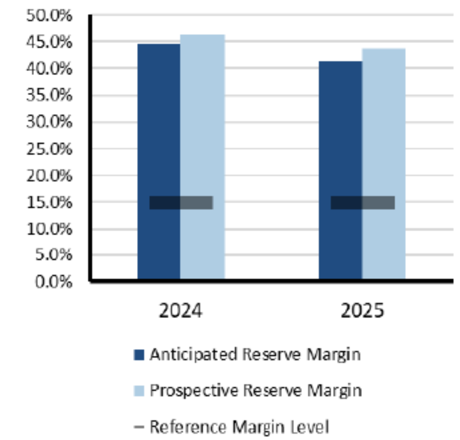
SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. 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 FERC-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 Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

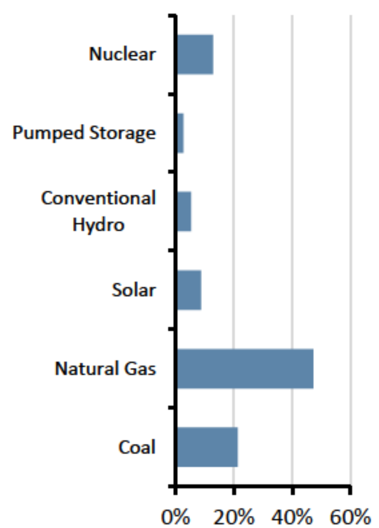
On-Peak Reserve Margin



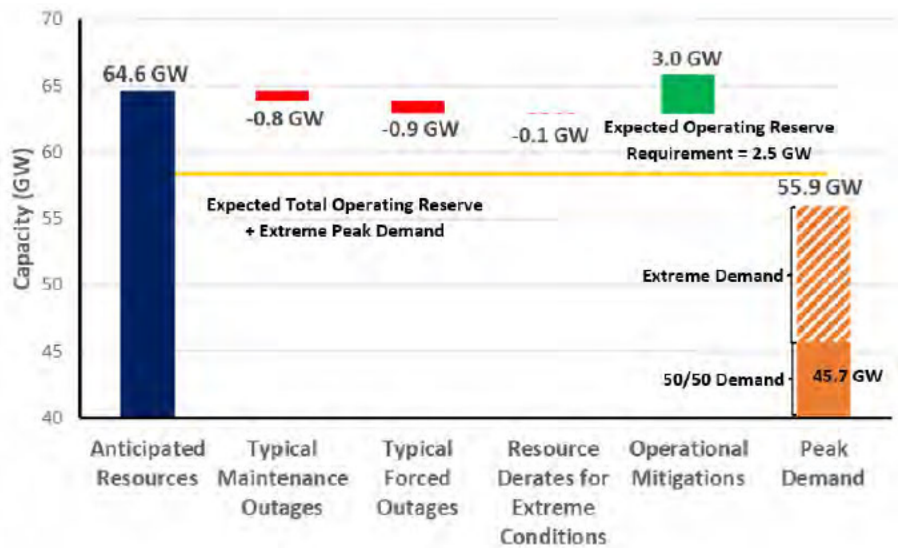
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

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

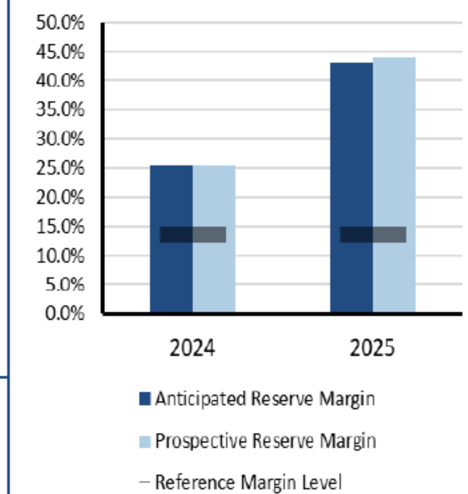
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

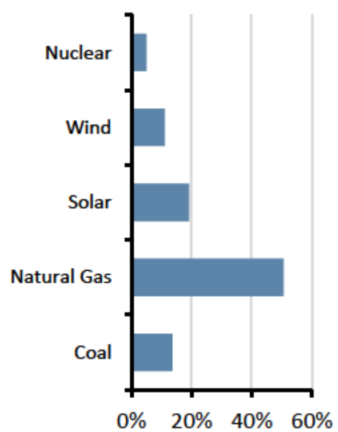
On-Peak Reserve Margin



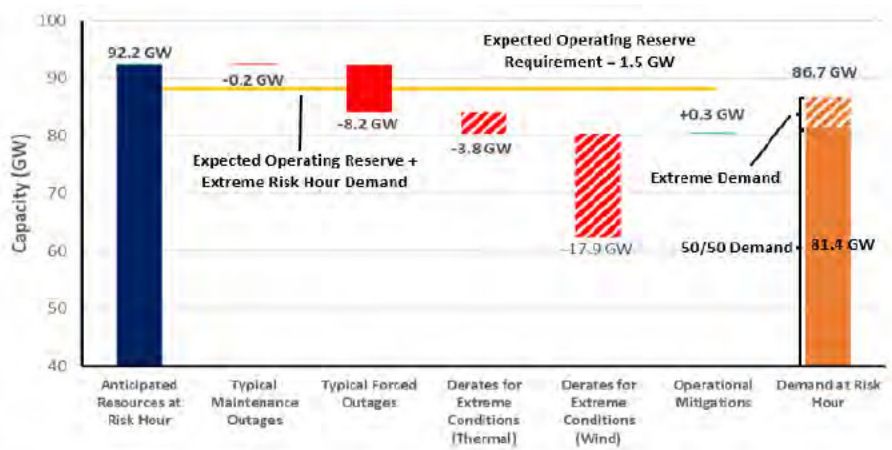
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports

WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

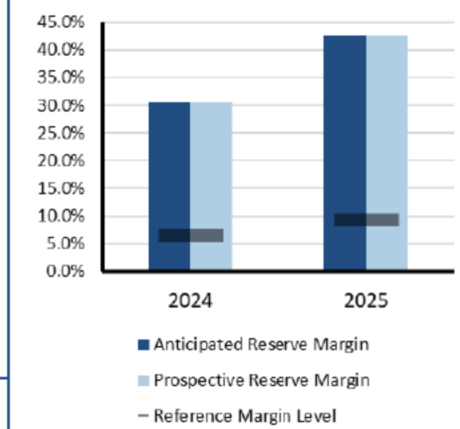
Highlights

- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

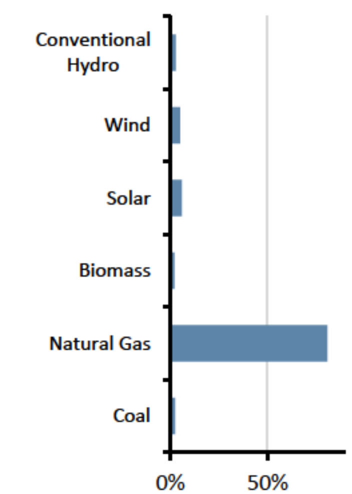
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

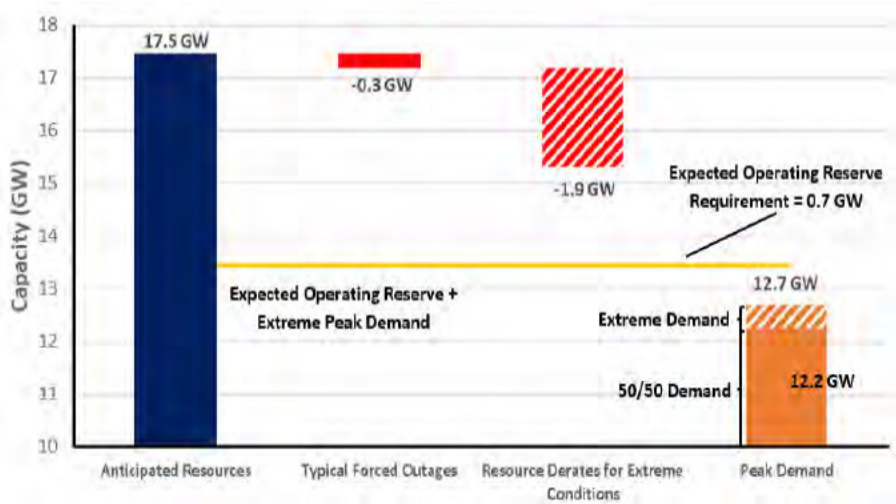
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

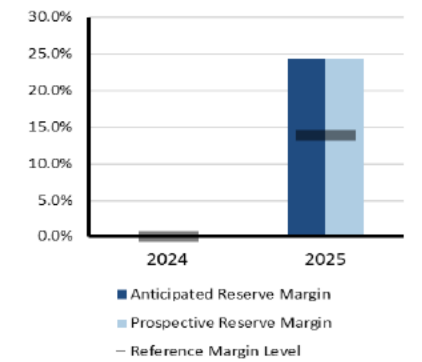
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

Risk Scenario Summary

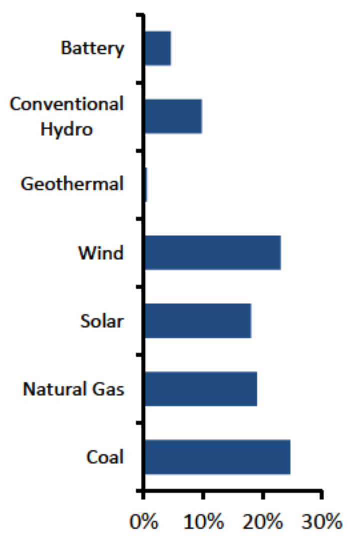
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

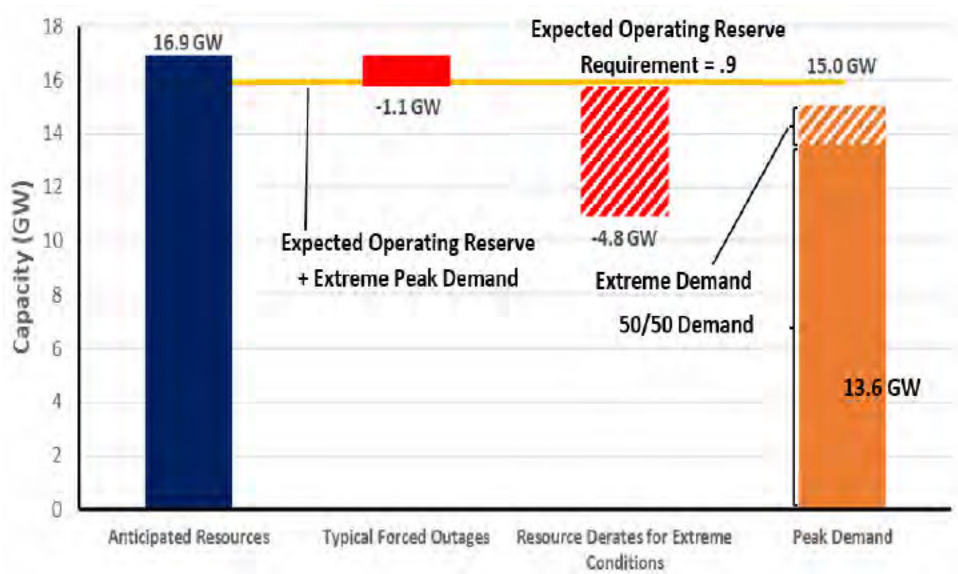
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

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

WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

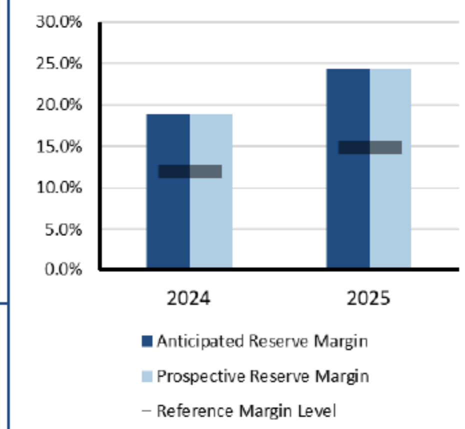
Highlights

- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

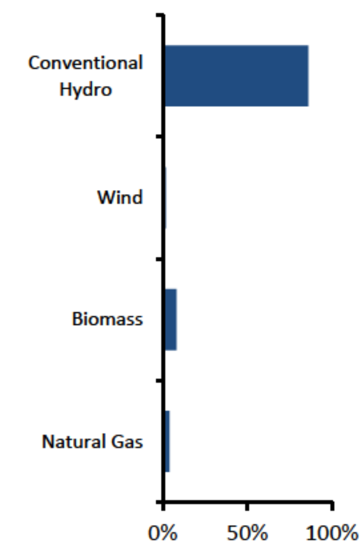
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

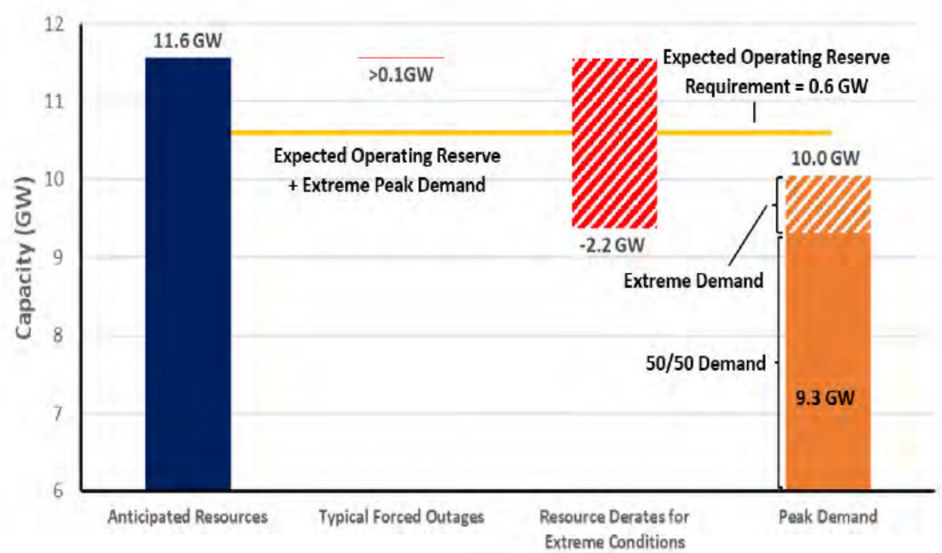
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

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

WECC-California

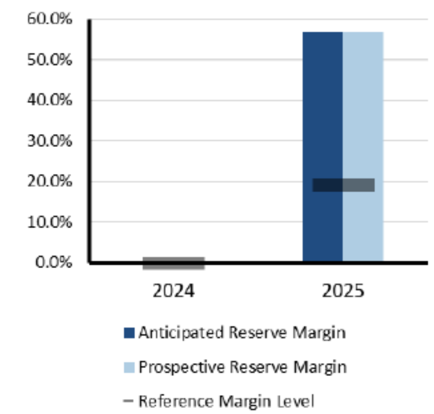
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

On-Peak Reserve Margin

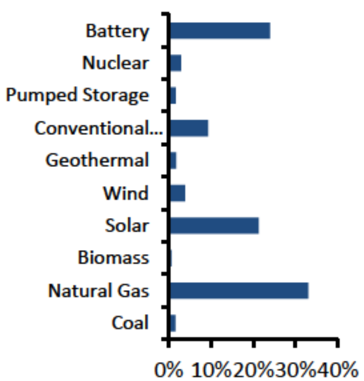
(Note: year comparison not available)



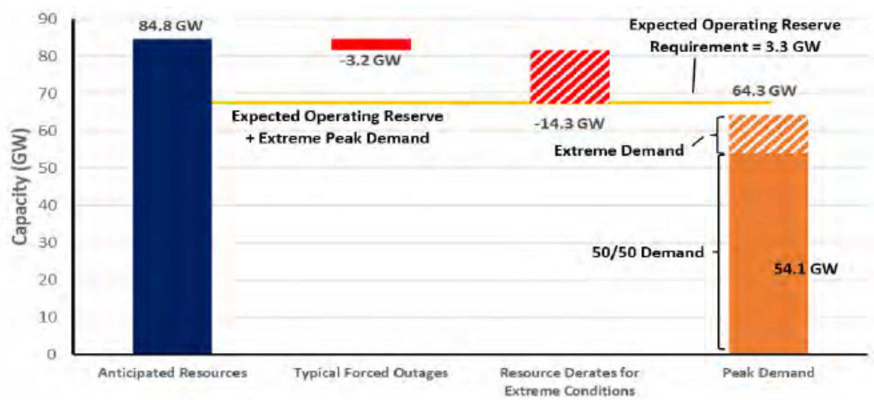
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Estimated using market forced outage model

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

WECC-Mexico

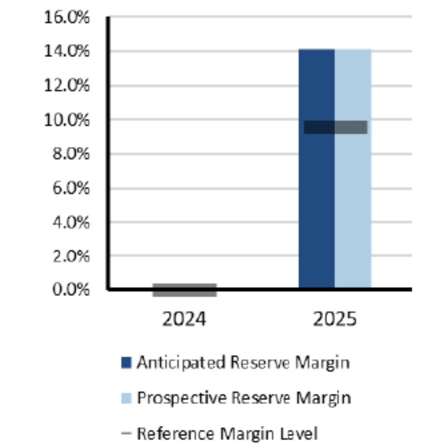
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

On-Peak Reserve Margin

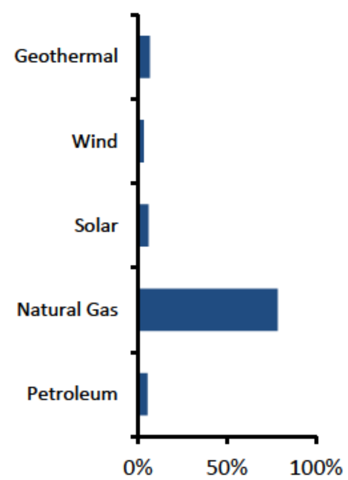
(Note: year comparison not available)



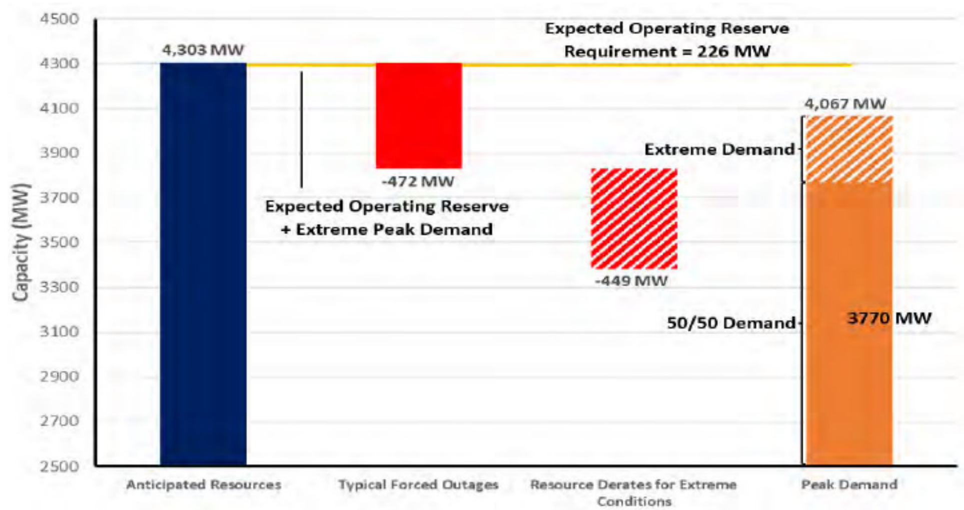
Risk Scenario Summary

Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

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

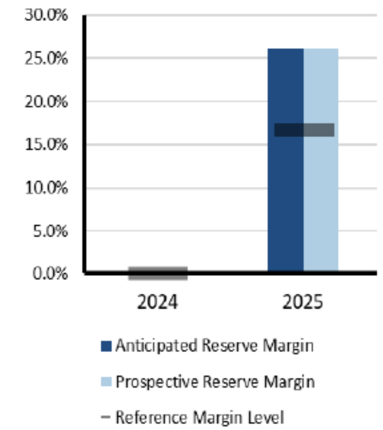
WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

On-Peak Reserve Margin

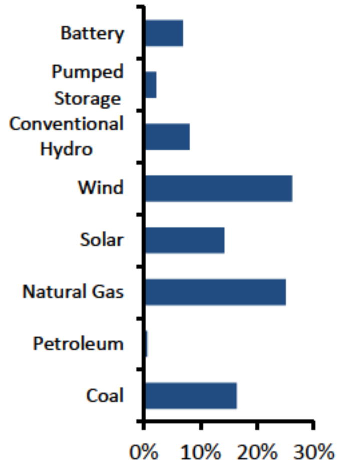


(Note: year comparison not available)

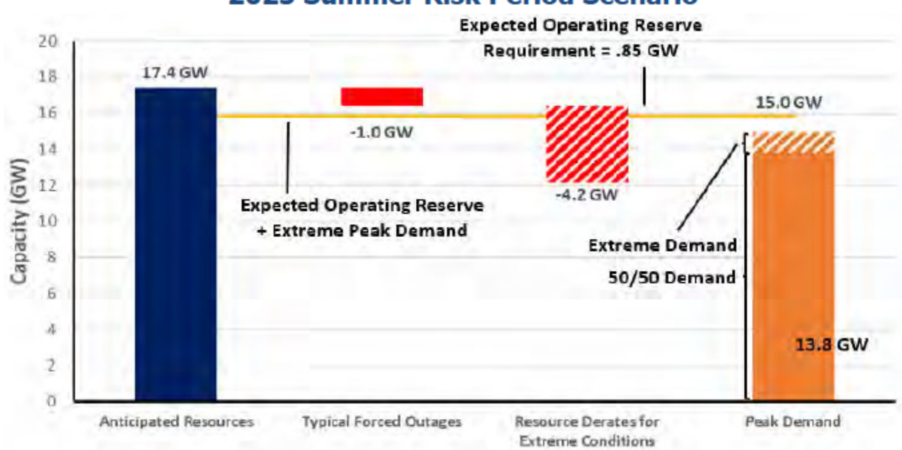
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA.*

Highlights

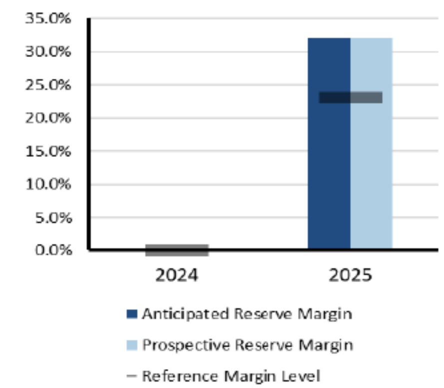
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

Risk Scenario Summary

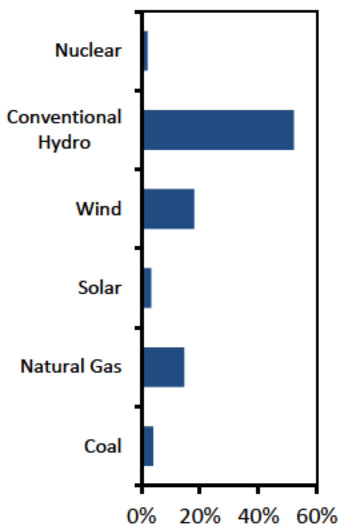
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

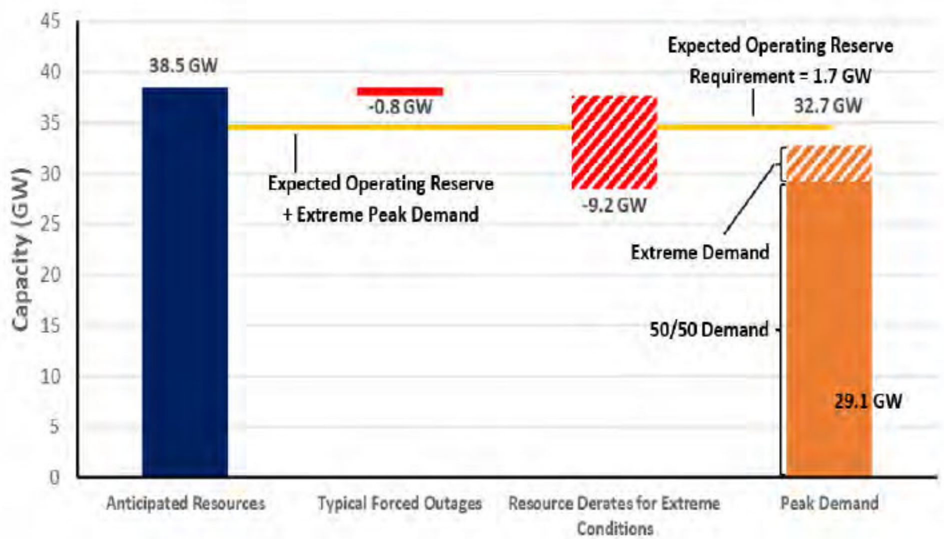
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-Southwest

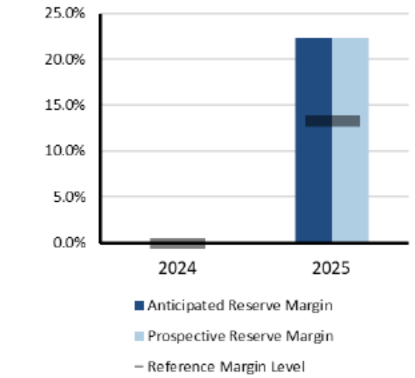
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

On-Peak Reserve Margin

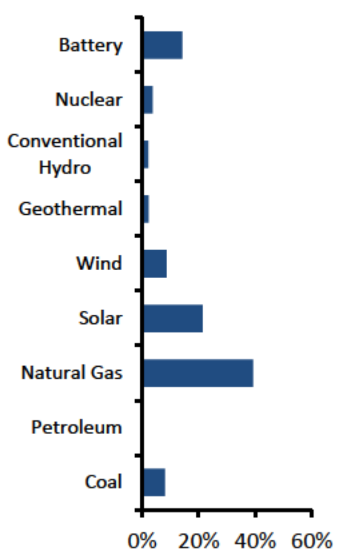
(Note: year comparison not available)



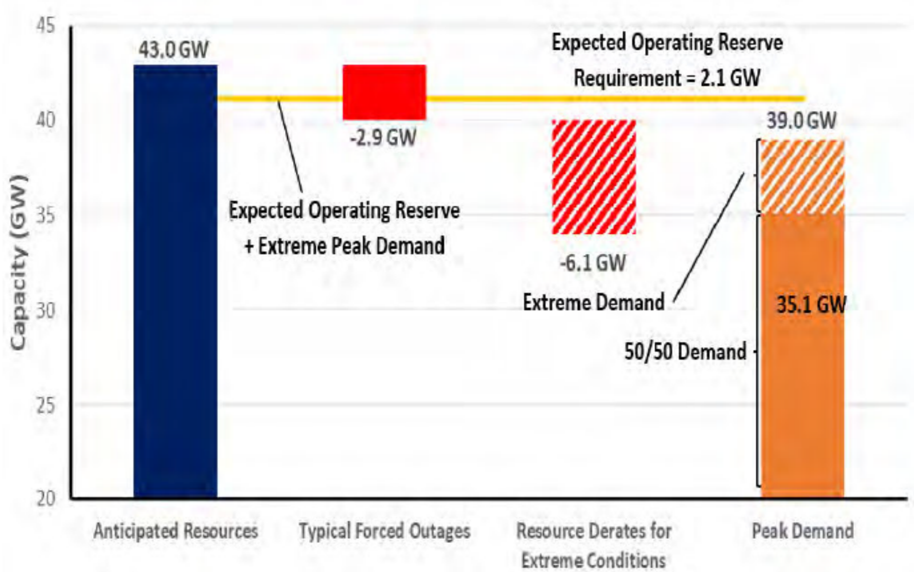
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour 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 electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
  - Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
- The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
- All data in this assessment is based on existing federal, state, and provincial laws and regulations.
- Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
- A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.

Demand Assumptions

- Electricity demand projections, or load forecasts, are provided by each assessment area.
- Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
- Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
- Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

Resource Assumptions

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

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

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

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

[14] 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.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions
Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.
Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] 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 ARMs to meet or exceed their RML for the summer 2025 as shown in Figure 4.

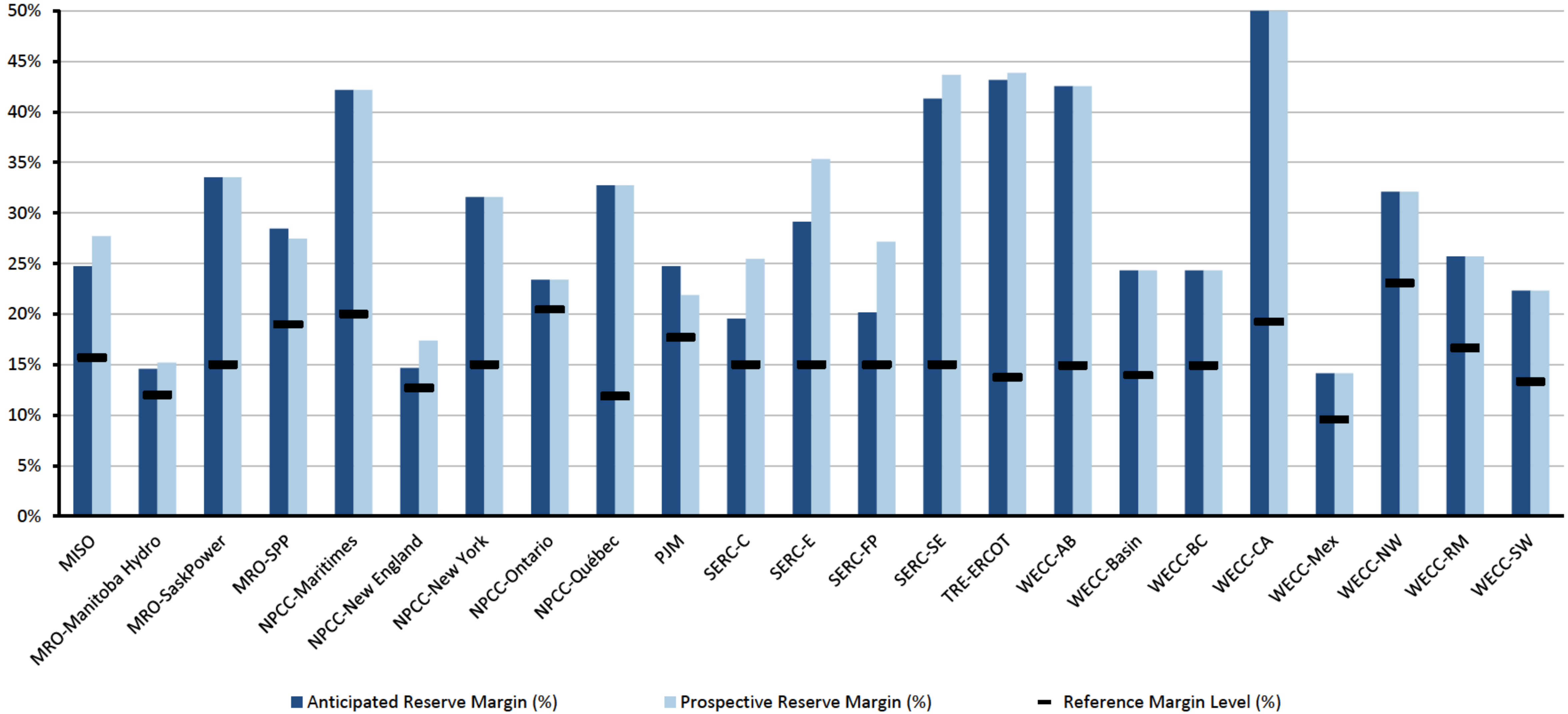

Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

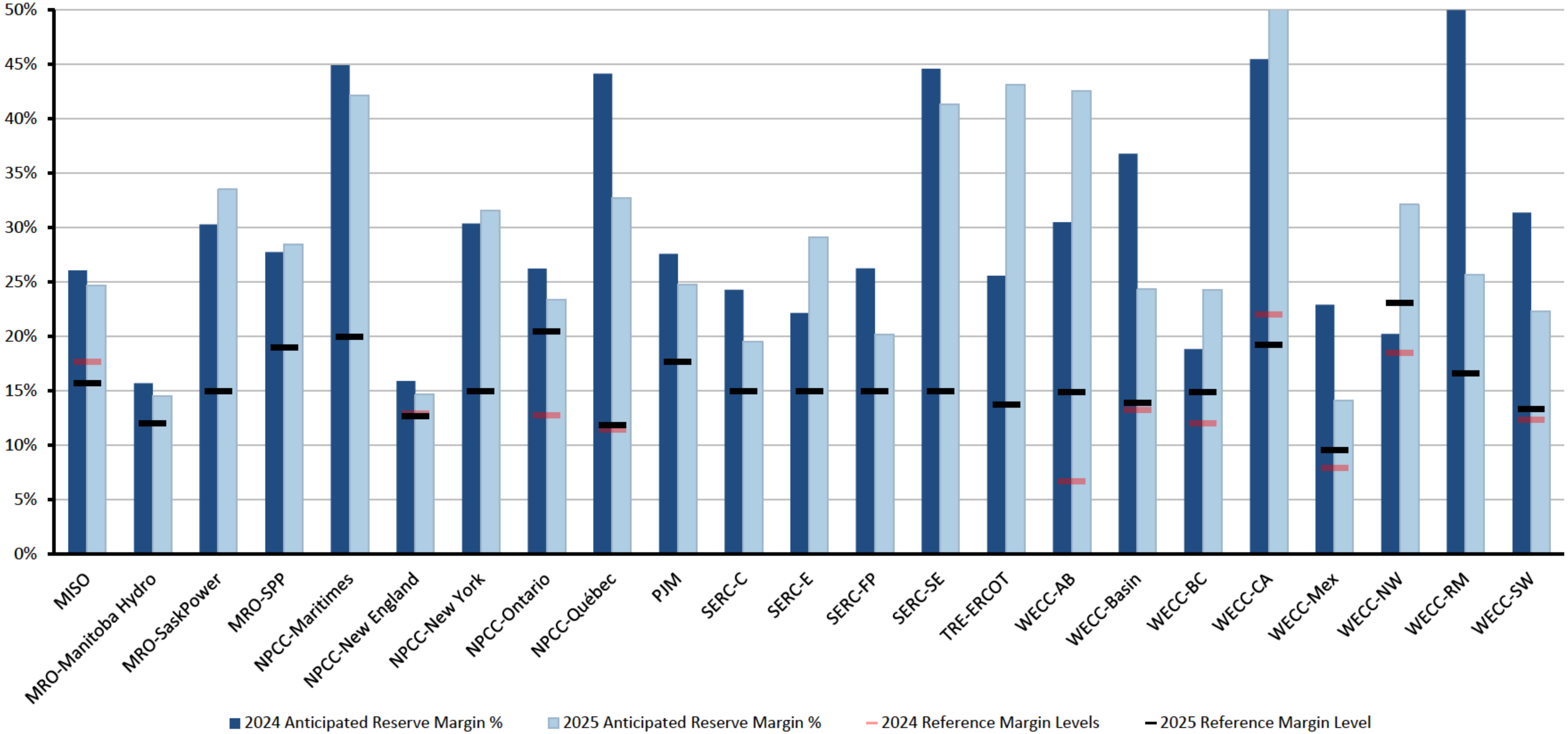

Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

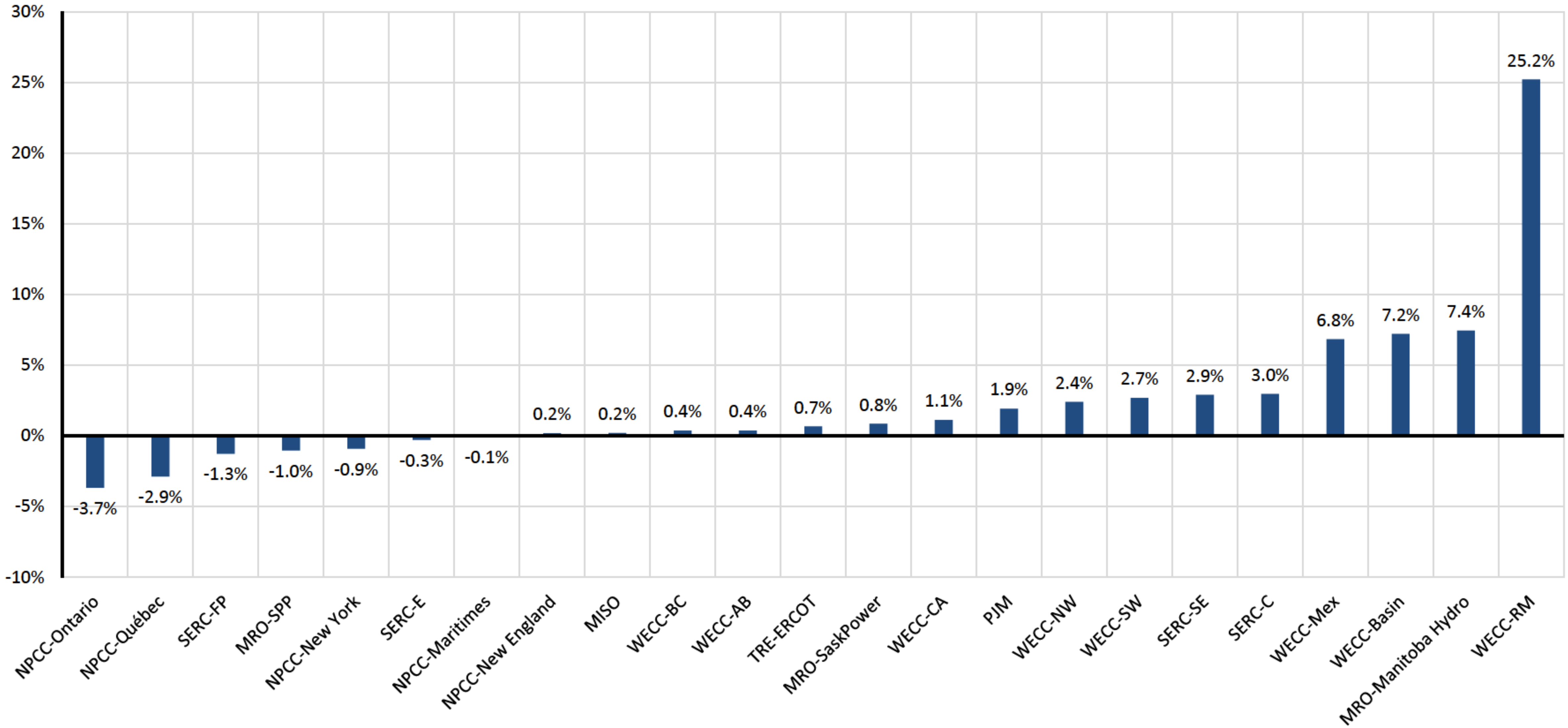

Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area												
	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	175,081	34,774	20%	142,014	86,170	61%	101,959	65,290	64%	36,311	32,298	89%

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

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[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta’s demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.

[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2024 SRA*.

[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.

*Values include both maintenance and forced outages.

**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-28:
2019–24 NERC Summer Reliability Assessments

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Summer Reliability Assessment

June 2019

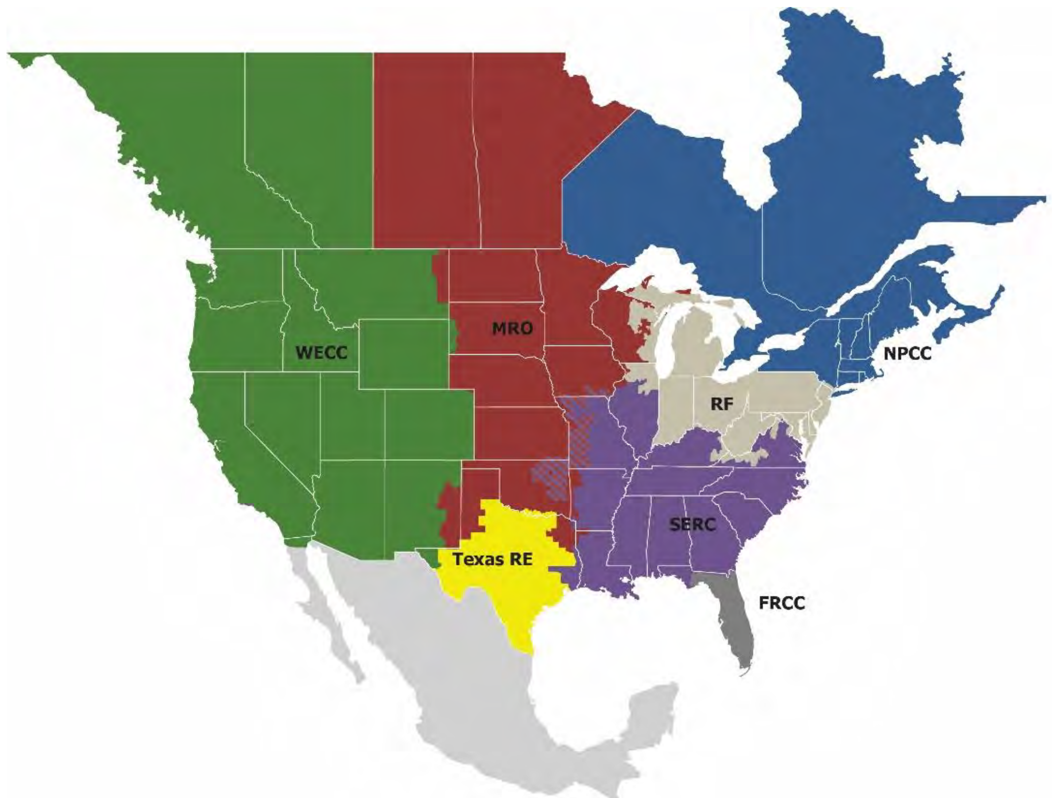
Table of Contents

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven 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. The North American BPS is divided into seven REs with boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Region 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 Assessment Dashboards** section.

About this Report

NERC's *2019 Summer Reliability Assessment* identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, this assessment 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 Regions, and NERC staff. This report 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 report also provides an opportunity for the industry to discuss their plans and preparations to ensure reliability for the upcoming summer period.



Key Findings

NERC's annual *Summer Reliability Assessment* covers the four-month Summer 2019 (June–September) period. This assessment provides an evaluation of whether there is adequate generation and transmission necessary to meet projected summer peak demands. The assessment monitors and identifies potential reliability issues and regional areas of concern that pertain to meeting projected customer demands. The following key findings represent NERC's independent evaluation of electric generation capacity and potential operational concerns that may need to be addressed:

- **ERCOT anticipates Energy Emergency Alerts may be needed to address resource shortfalls during periods of peak demand.** In ERCOT, the Anticipated Reserve Margin remains below the Reference Margin Level of 13.75%. ERCOT's Anticipated Reserve Margin decreased from 10.9% in Summer 2018 to 8.5% for the upcoming summer season. The reduction is caused by higher load growth, a planned generator retirement, and delays in new generation. If resource shortfalls occur, ERCOT anticipates implementing operating mitigations. These measures include importing additional power if available and energy emergency alerts that allow ERCOT to trigger emergency procedures such as voluntary load reduction.
- **Most assessment areas meet or exceed Reference Margin Levels and have sufficient electricity resources for anticipated conditions and more extreme scenarios.** In all areas, with the exception of ERCOT, the Anticipated Reserve Margin meets or surpasses the Reference Margin Level, indicating that planned resources in these areas are adequate to manage loss of load risk under normal conditions.[1] NERC also examined more extreme resource and demand conditions in each assessment area through seasonal risk scenarios. In some assessment areas, extreme summer peak loads and low-probability generator outage scenarios can result in insufficient resources to meet expected operating reserve requirements. In instances where operating reserve requirements are not met, system operators should employ operating procedures and mitigations, which may include demand response, Energy Emergency Alerts that support increased transfers, and other operational mitigations to manage resources and loads.
- **California faces ramping capability concerns.** In the California Independent System Operator (CAISO) area, there is the potential for operational risks at certain times of day as a result of shortages in resources with upward ramping capability. These shortage conditions are more prevalent during late afternoon as solar generation output decreases while system demand is still high. Transfers from neighboring areas may be needed during normal conditions when short on load-following resources capable of ramping up within the CAISO area.
- **Natural-gas-fired electric generation in Southern California will continue to need fuel from natural gas storage facilities for summer reliability.** The natural gas system operator in Southern California assesses that supplies from interstate pipelines alone may not be sufficient to meet the needs of all customers on summer peak load days, leaving electric generators at risk of curtailment. As a result, withdrawals from the Aliso Canyon natural gas storage facility would be necessary to ensure adequate fuel for generators in the Southern California area.
- **Elevated risk for wildfires in Western United States and parts of Canada poses risk to BPS reliability.** Government agencies predict above-normal wildfire risk for summer throughout parts of North America. Operation of the BPS can be impacted in areas where wildfires are active, as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. In some areas, pre-season planning includes expanded public safety power shut-off programs in addition to maintenance and operational preparations.

[1] For more information, see the description of the "Reference Margin Level" in the **Data Concepts and Assumptions** section of this report, or refer to NERC's Long-term Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

Resource Adequacy

NERC uses the Anticipated Reserve Margin to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecasted peak load.[2] Large year-to-year changes in anticipated resources or forecasted peak load can greatly impact Planning Reserve Margin calculations. As shown in **Figure 1**, other than Texas RE-ERCOT, all assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their planning Reference Margin Level for the Summer 2019 period. Discussion of significant changes to Anticipated Reserve Margins in the Texas RE-ERCOT and WECC assessment areas are provided in the following sections.

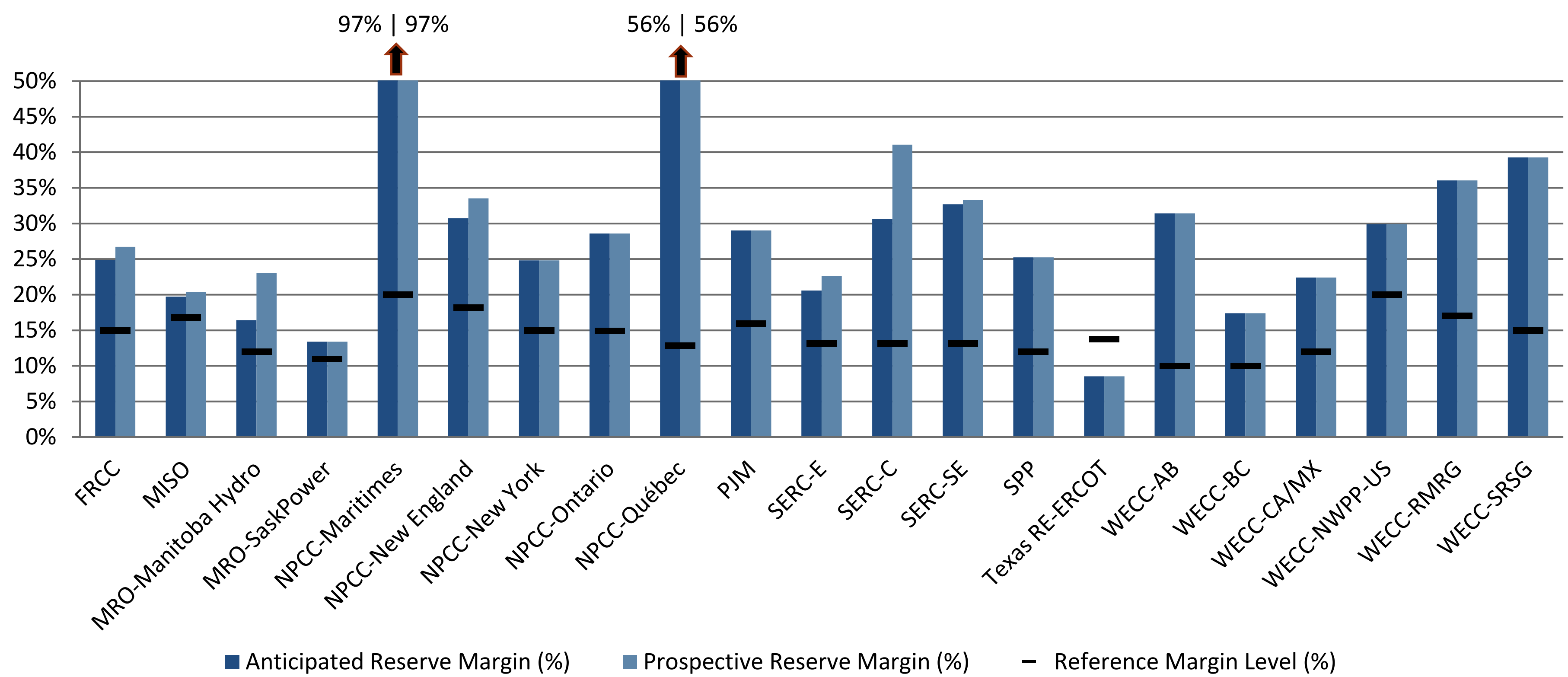


Figure 1: Summer 2019 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[2] Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated Reserve Margins, Anticipated Resources, and Reference Margin Levels.

Changes from Year-to-Year

Understanding the changes from year-to-year is an essential step in assessing an area on a seasonal basis. This understanding can be used to further examine potential operational issues that emerge between reporting years. Figure 2 provides the relative change from the Summer 2018 to the Summer 2019 period.

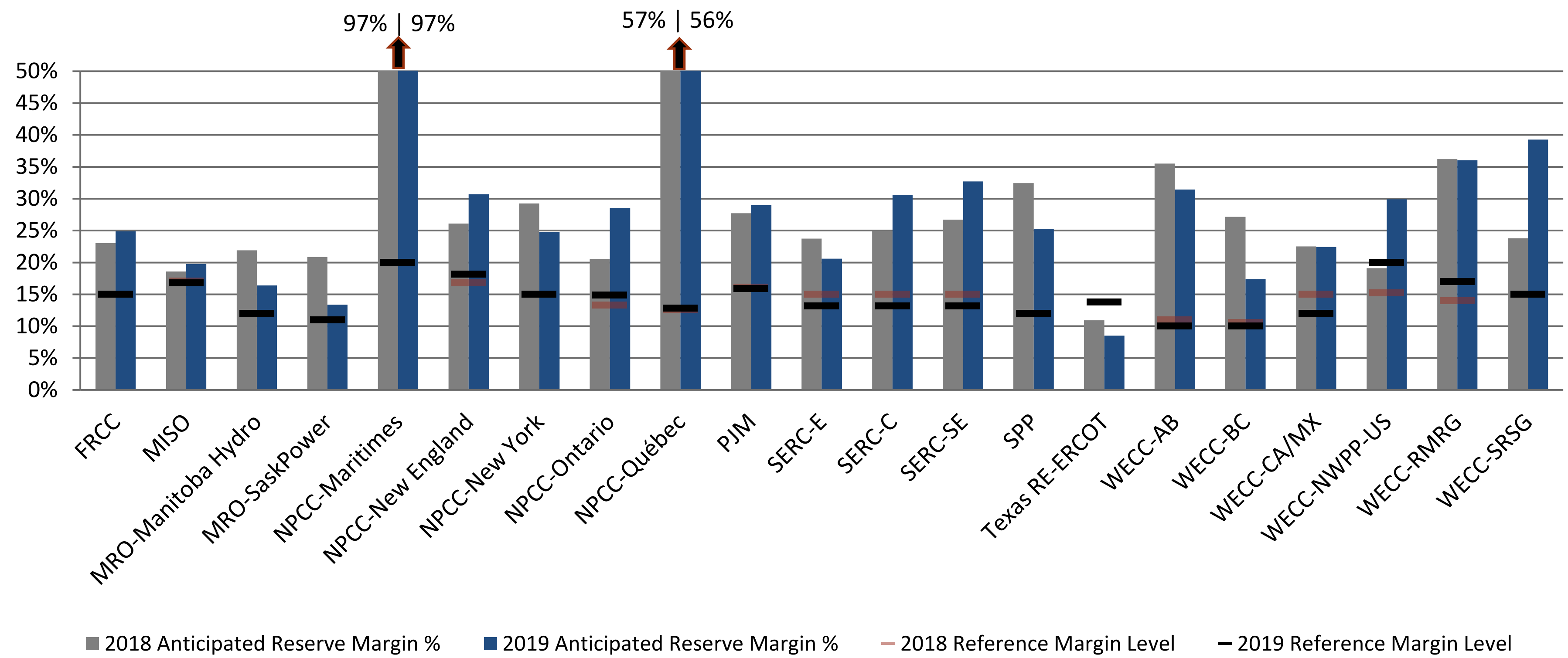


Figure 1: Summer 2018 to Summer 2019 Anticipated Reserve Margins Year-to-Year Change

Risk Highlights for Summer 2019

Tight Reserve Margins in Texas Lead to Operational Challenges

Texas RE-ERCOT enters the Summer 2019 season with a deficit in planning reserves, increasing the likelihood that system operators may need to employ procedures to maintain sufficient operating reserves. In 2018, ERCOT maintained sufficient generation resources through record levels of summer peak demand without resorting to Energy Emergency Alerts. This system performance, due in large part to high levels of generator availability, response to market signals, and unit performance, was notable given the Anticipated Reserve Margin of 10.9%, well-below the Reference Margin Level of 13.75%.[3] For the upcoming summer, growth in anticipated summer peak demand, delays in planned generation projects, and the announced mothballing of a 470 MW coal-fired unit (Gibbons Creek) are expected to push reserve margins still lower, to 8.5%.

Based on ERCOT's summer Seasonal Assessment of Resource Adequacy (SARA) report, released May 8, ERCOT expects that a number of operational tools may be needed this summer to help maintain sufficient operating reserves given the range of resource adequacy scenarios they evaluated.[4] For example, ERCOT system operators can release ancillary services (including load resources that can provide various types of operating reserves based on meeting certain qualification criteria), deploy contracted emergency response service resources, instruct investor-owned utilities to call on their load management and distribution voltage reduction programs, request emergency power across the dc ties, and request support from available switchable generators currently serving non-ERCOT grids.

The SARA report informs ERCOT market participants and operators by deterministically considering the impact of potential variables that may affect the sufficiency of resources for the upcoming season. Historic ranges or expectations for generation maintenance outages, forced outages, and capacity derates during extreme weather conditions are applied deterministically as resource scenarios. The effect of these resource scenarios, along with normal and extreme peak demand scenarios, are examined to determine the potential for scarcity conditions and emergency operating procedure mitigation. **Figure 3** shows a risk assessment developed by NERC using *Summer Reliability Assessment* data and additional data from Texas RE-ERCOT, and the ERCOT 2019 Preliminary SARA report. A description of resource and demand variables is found in **Table 1**.

[3] See ERCOT's 2018 Summer Performance Update: http://www.ercot.com/content/wcm/lists/144927/2018_Summer_Performance_One_Pager_FINAL.pdf
[4] For details see ERCOT's SARA Report: http://www.ercot.com/content/wcm/lists/167022/SARA-FinalSummer2019.xlsx

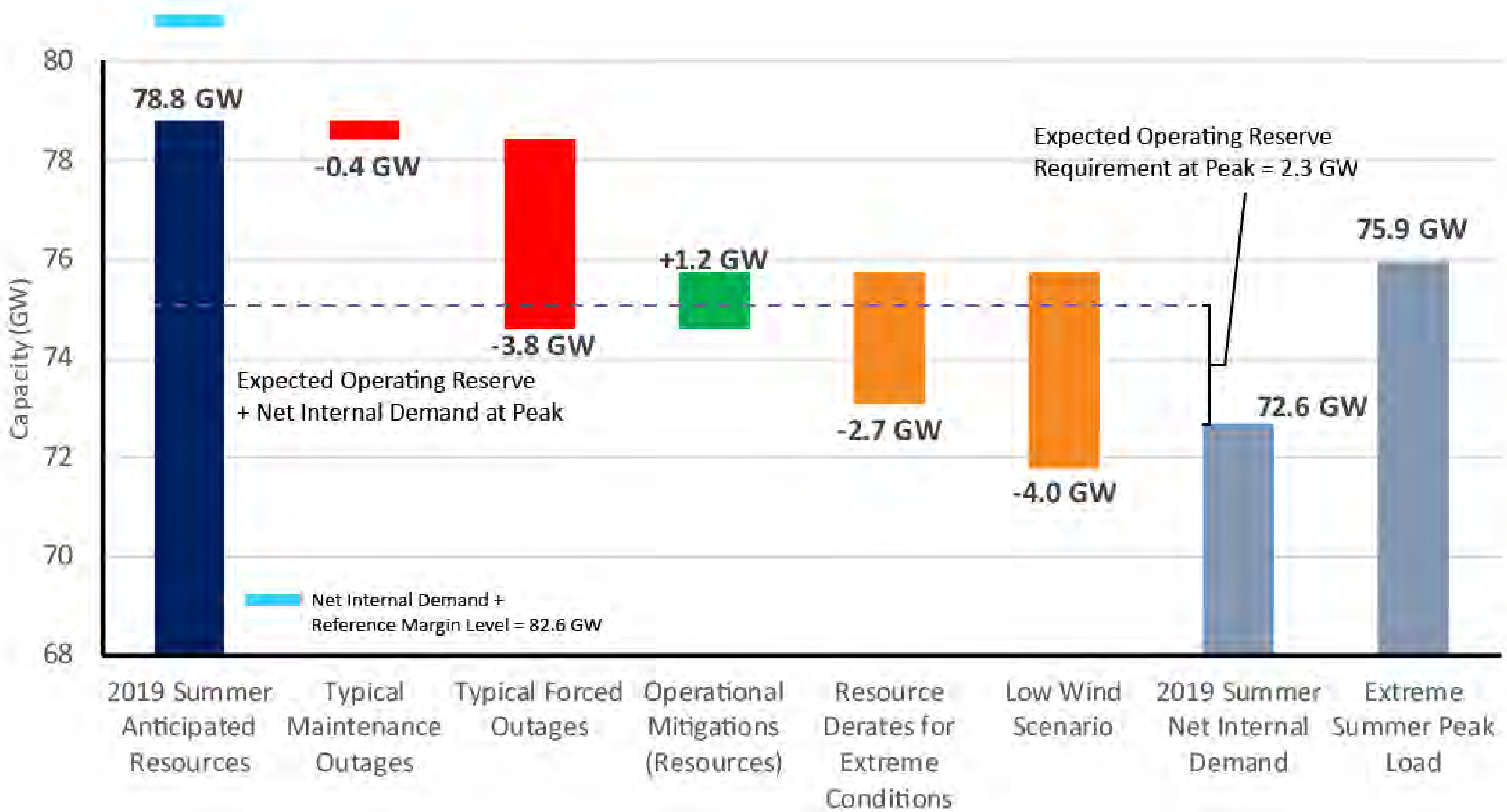


Figure 3: Texas RE-ERCOT Seasonal Risk Assessment

About the Seasonal Risk Assessment The operational risk analysis shown in Figure 3 provides a deterministic scenario for understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to summer anticipated capacity, such as the following:

- Reductions for typical generation outages (maintenance and forced, not already accounted for in summer anticipated resources)
- 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 SRA 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 summer 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 Texas RE-ERCOT seasonal risk scenario in Figure 3 can be found for each assessment area in the Regional Assessment Dashboards section of this report.

Table 1: Resource and Demand Variables in the ERCOT Seasonal Risk Assessment	
Resource Scenarios	
Typical Maintenance Outages	Typical maintenance outages refer to an estimate of generation resources that will be out for maintenance during peak load conditions. A value of 381 MW was determined based on the historical average of maintenance outages for June through September weekdays, for the last three summer seasons (2016–2018). Planned maintenance outages are generally accounted for in anticipated summer resources, however, this reduction covers additional generator outages granted by operators on a short-term basis as warranted by system conditions.
Typical Forced Outages	Typical forced outages refer to an estimate of generation resources that will experience forced outage during peak load conditions. A value of 3,845 MW is based on historical average of forced outages for June through September weekdays, for the last three summer seasons (2016–2018).
Operational Mitigations	ERCOT assesses that certain operational mitigations, in addition to operating measures accounted for in SRA data and the preliminary SARA Report, can contribute 1,160 MW of additional resources to support maintaining operating reserve requirements. This value is based on three elements: • Switchable generation resources currently serving the Southwest Power Pool (SPP) market that could become available to ERCOT in the event of an energy emergency (total of 489 MW) • Additional imports from the dc tie with the Mexican grid and from SPP beyond what was designated as long-term firm imports (total of 221 MW) • Distribution service providers implementation of distribution voltage reduction (contributing a total of 450 MW)
High Forced Outage Scenario (Low-likelihood Resource Derates)	A low-likelihood, high forced outage scenario is used to analyze the effect of extreme weather-driven generation outages. A capacity adjustment of 2,665 MW from the preliminary SARA report is based on historical forced outages assuming a 90% confidence interval.
Low-Wind Scenario (Low-likelihood)	The low-wind scenario is used to analyze the impact low-likelihood weather conditions that severely reduce output from wind generation resources. A capacity adjustment of 3,960 MW is based on a low wind output scenario included in ERCOT's preliminary summer SARA report. This capacity amount is calculated as the tenth percentile of wind output associated with the 100 highest net load hours (load minus wind output) for the 2015–2018 summer peak load seasons.
Demand Scenarios	
2019 Net Internal Demand	Net internal demand 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. It is based on historical average weather (i.e., forecasts for a 50/50 distribution).
Extreme Summer Peak Load	A seasonal load adjustment (3,303 MW) is added to 2019 net internal demand based on extreme weather conditions that occurred during Summer 2011. ERCOT compared this value to a statistical extreme load forecast (i.e., a "90/10 load forecast" and found the Summer 2011 peak load to be higher and therefore a more conservative scenario.

ERCOT's tight reserve margins create a potential need to declare an energy emergency alert under many of the peak and extreme conditions studied in the SARA.[5] Once normal operating actions to maintain operating reserves are exhausted, energy emergency alerts can provide system operators with access to additional resources as discussed above that are only available during scarcity conditions. ERCOT also anticipates that higher wholesale market prices during peak demand periods will incentivize power customers to voluntarily reduce load or increase energy output from load-serving generation facilities (such as industrial cogeneration and commercial-sector distributed generation) that can inject power into the ERCOT system. Based on recent ERCOT analysis, the potential amount of this demand and generation response for the upcoming summer is significant but uncertain because the ERCOT market has not experienced summer high prices subsequent to the market design changes implemented in 2012–2014.

Seasonal Risk Assessments for Other Areas

Any area can face resource adequacy risk during peak conditions, even when Planning Reserve Margins exceed Reference Margin Levels. The reasons can be similar: generator scheduled maintenance, forced outages due to normal and more extreme weather conditions and loads, as well as 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 where appropriate, the potential effects that operating actions can have to mitigate shortfalls in operating reserves.

CAISO Faces Concerns with Ramping Capability, Natural Gas Supply

For Summer 2019, the risk of resource shortfalls in CAISO is lower than last summer. However, there is increased risk of insufficient ramping capability during peak conditions. Conditions for hydroelectric generation are well above normal due to replenishment of reservoirs and mountain snow during the preceding winter, greatly reducing the potential for operating reserve shortfalls. However, the *2019 Summer Loads and Resources Assessment* highlights concerns with shortages in load-following resources capable of ramping up, particularly during late afternoon when solar generation output decreases while system demand is still high.[6] Increasing penetrations of solar resources and the retirements of dispatchable generation units has contributed to a shortage of ramping resources. When faced with such shortages, operators will need to call upon neighbors for imports to maintain system frequency. Should extreme temperatures extend over a large area to the point where neighbors lack surplus energy, load could be at risk from a shortage in ramping capability.

The impacts to electric generation resulting from operating restrictions at the Aliso Canyon natural gas storage facility remain an item of focus for electric reliability within the Western Interconnection. Withdrawals from natural gas storage facilities were at a high level during Winter 2018–2019 due to colder than average winter temperatures, resulting in below average storage levels approaching the Summer 2019 season. The Southern California Gas Company (SoCalGas) forecasts that it will be able to meet the forecasted peak day demand under a "best case" supply assumption even without supply from Aliso Canyon.[7] However, under a worst case supply assumption, supply from Aliso Canyon will be necessary to meet that forecasted peak day demand. Should operating restrictions result in natural gas supply curtailments that affect electric generation in the Southern California area, mitigation procedures that have been in place since 2016 can be used to maintain BPS reliability.

In addition to managing natural gas storage to meet summer demand, SoCalGas also uses summer months to begin increasing storage levels in preparation for peak winter months. Winter storage levels can be impacted in some scenarios that involve reduced natural gas storage receipts due to supply infrastructure servicing.

[5] A description of Energy Emergency Alerts and processes for communicating and coordination during operating emergencies is contained in NERC Reliability Standard *EOP-011-1 – Emergency Operations* available at the following link: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf

[6] See CAISO 2019 Summer Loads and Resources Assessment here: http://www.caiso.com/Documents/2019SummerLoadsandResourcesAssessment.pdf

[7] See Southern California Gas Company (SoCalGas) *2019 Summer Technical Assessment*, April 4, 2019, available at the link below. At the time of drafting the NERC 2019 SRA, the California Public Utilities Commission (CPUC) summer technical assessment for Aliso Canyon had not been released. The CPUC assessment is expected to provide the most current and comprehensive information, including potential impacts to the BPS in Southern California.
http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/SoCalGas%20Summer%202019%20Technical%20Assessment%20040219.pdf

Mitigation Operating Plans

Should CAISO system operating conditions go into the emergency stages, such as operating reserve shortfalls where non-spinning reserve requirement cannot be maintained or spinning reserve is depleted and operating reserve falls below minimum requirement, the following mitigation operating plan will be implemented to minimize loss of load in the CAISO Balancing Authority area:

- Use the Flex Alert program, signaling that the CAISO expects high peak load condition. This program has been proven to reduce peak load in the CAISO Balancing Authority area.
- Use the CAISO Restricted Maintenance program. This program is intended to reduce potential forced outages, therefore, minimizing forced outage rate during the high peak load condition.
- Perform manual post day-ahead unit commitment and exceptional dispatch of resources under contract to ensure the ability to serve load and meet flexible ramping capability requirements.
- Perform manual exceptional dispatch of intertie resources that have resource adequacy obligation to serve CAISO load.
- Use the CAISO Alert/Warning/Emergency (AWE) program.
- Use the demand response program including the Reliability Demand Response Resources (RDRR) under the “Warning” stage.
- Perform manual exceptional dispatch of physically available resources that are not under capacity contract.

Wildfire Risk and Potential for Impacts to the BPS

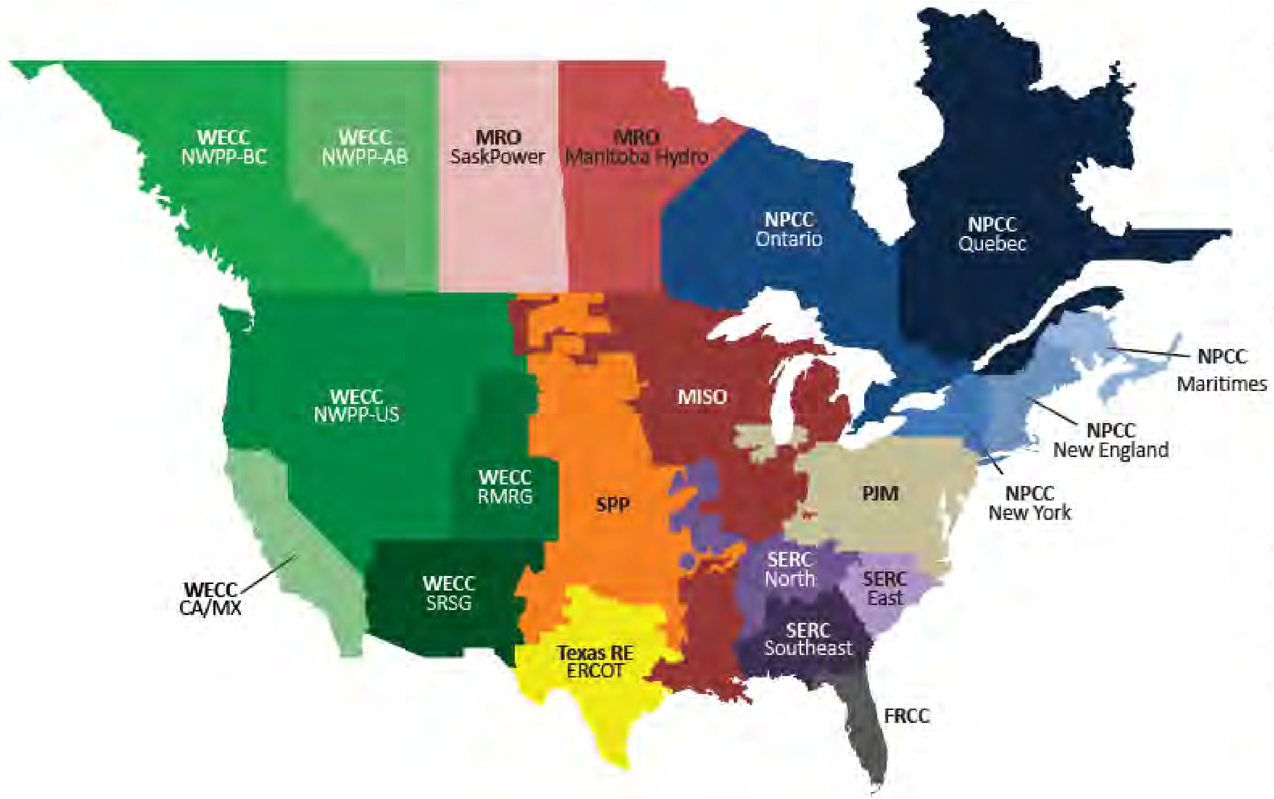
Government agencies predict above-normal wildfire risk for the summer throughout parts of North America. The National Interagency Fire Center, Natural Resources Canada, and National Meteorological Service in Mexico published a three-month seasonal potential wildfire outlook (April-June), which predicts above normal wildfire potential for California and the Pacific Northwest (Western Oregon and Washington), Western Alberta, British Columbia, and Northern Mexico.[8]

Operation of the BPS can be impacted in areas where wildfires are active, as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. With the widely dispersed nature of the transmission system in western parts of North America, outages due to wildfires are generally not widespread. Furthermore, utilities are enhancing wildfire prevention planning in California and other areas to address increased risk. In some cases, plans could include expanding power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines, including transmission-level lines, may be preemptively deenergized in high fire-risk areas to prevent wildfire ignitions. Other activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures.

[8] See the *North American Seasonal Fire Outlook*, issued May 10, 2019: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

Regional Assessment Dashboards

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



FRCC – Florida Reliability Coordinating Council
- FRCC

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

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

RF – ReliabilityFirst
- PJM

SERC – SERC Reliability Corporation
- SERC-East
- SERC-North
- SERC-Southeast

SPP – Southwest Power Pool
- SPP

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT

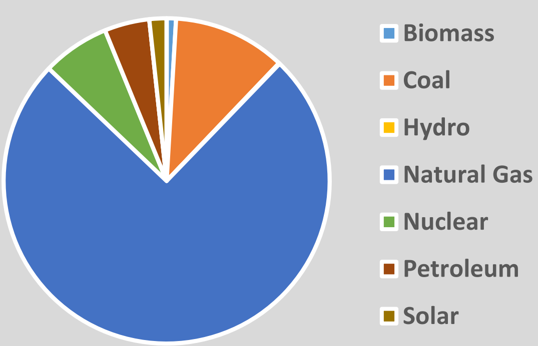
WECC
- WECC-CA/MX
- WECC-NWPP-AB
- WECC-NWPP-BC
- WECC-NWPP-US
- WECC-RMRG
- WECC-SRSG

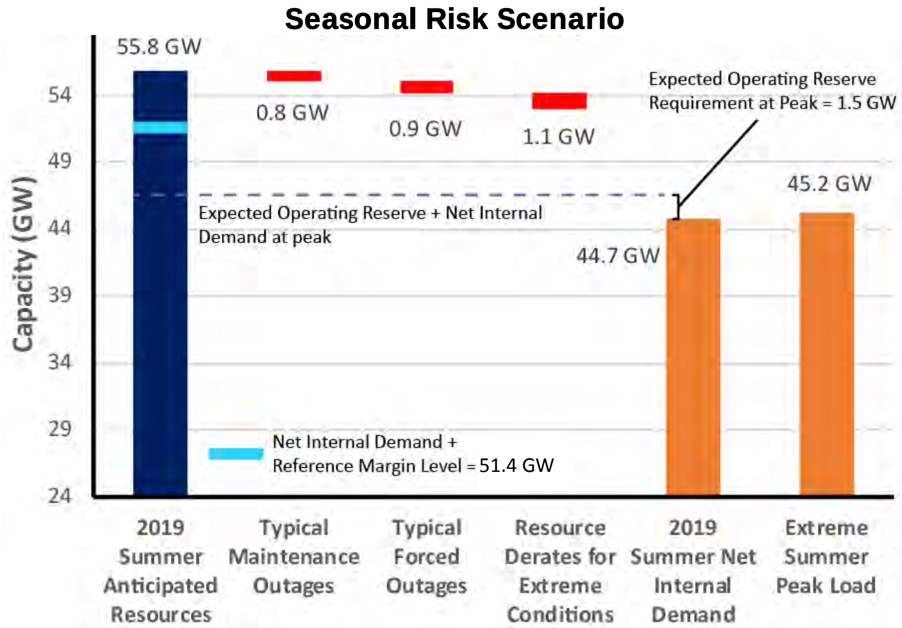
FRCC

The Florida Reliability Coordinating Council's (FRCC) membership includes 32 Regional Entity Division members and 22 Member Services Division members composed of investor-owned utilities, cooperatives, municipal utilities, power marketers, and independent power producers.

FRCC is divided into 10 Balancing Authorities with 36 registered entities (including both members and non-members) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. The Region contains a population of more than 16 million people and has a geographic coverage of about 50,000 square miles across Florida.

On-Peak Capacity: Generation Mix





FRCC Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	47,495	47,670	0.4%
Demand Response: Available	2,957	2,951	-0.2%
Net Internal Demand	44,538	44,719	0.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	53,010	52,163	-1.6%
Tier 1 Planned Capacity	321.6	2,221	> 100%
Net Firm Capacity Transfers	1,477	1,456	-1.4%
Anticipated Resources	54,809	55,840	1.9%
Existing-Other Capacity	763.9	834	9.2%
Prospective Resources	55,573	56,674	2.0%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	23.1%	24.9%	1.8
Prospective Reserve Margin	24.8%	26.7%	1.9
Reference Margin Level	15.0%	15.0%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. FRCC determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Historical average MW during summer season
- **Extreme Derates:** 3% capacity derate applied on all natural gas unit capacity

Highlights

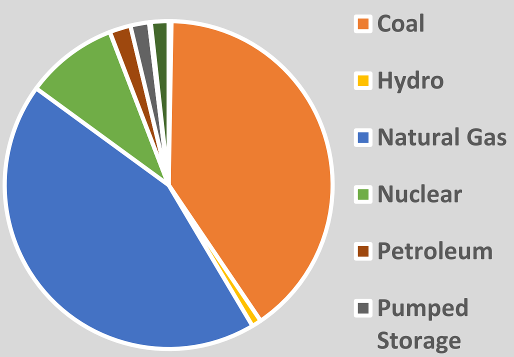
- FRCC has not identified any emerging reliability issues that are expected to impact reliability in the FRCC Region for the upcoming 2019 summer season.
- The BPS within the FRCC Region is expected to perform reliably for the anticipated 2019 summer season condition.
- On July 1, 2019, Regional Entity responsibilities will shift from FRCC to SERC for entities in Florida. FRCC will continue to provide member services and will remain a NERC assessment area.

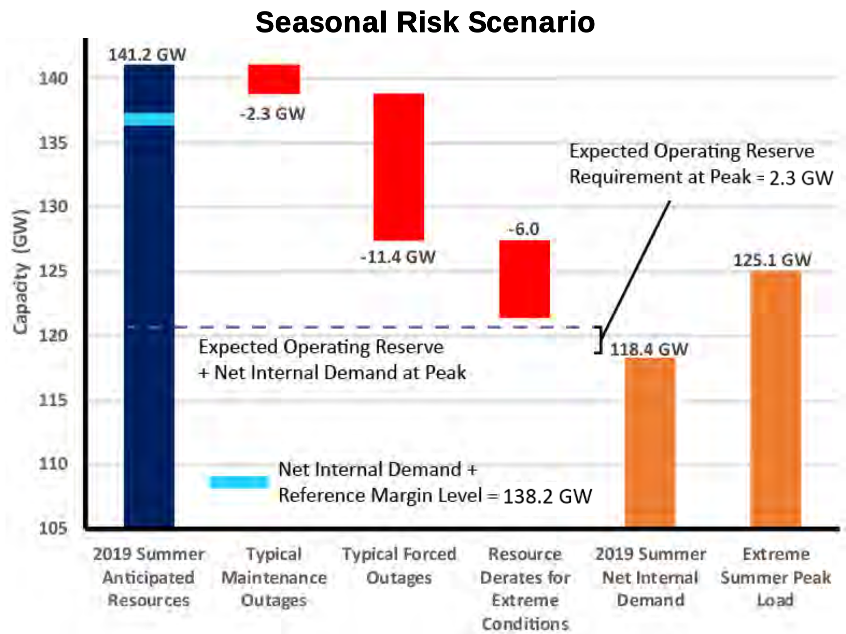
MISO

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 three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Capacity: Generation Mix





MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	124,704	124,744	0.0%
Demand Response: Available	5,990	6,385	6.6%
Net Internal Demand	118,714	118,359	-0.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	141,425	139,220	-1.6%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-8	1,955	-
Anticipated Resources	141,417	141,175	-0.2%
Existing-Other Capacity	1,104	591	-46.5%
Prospective Resources	142,521	141,766	-0.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	19.1%	19.3%	0.2
Prospective Reserve Margin	20.1%	19.8%	-0.3
Reference Margin Level	17.1%	16.8%	-0.3

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MISO determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under normal peak load scenario. Extreme summer peak load and outage conditions could result in the need to employ operating mitigation to manage resource shortfall.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Average from highest peak hour over the past five summers
- **Extreme Derates:** Additional outages based on analysis of past five years summer peak outages

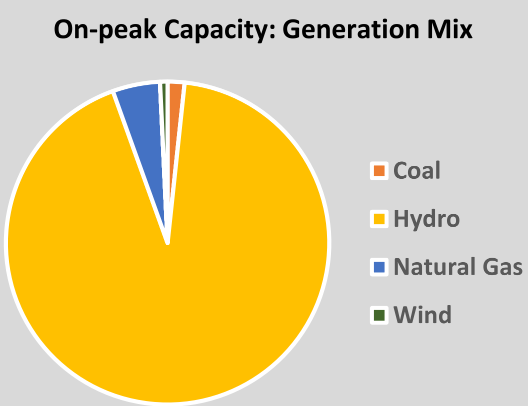
Highlights

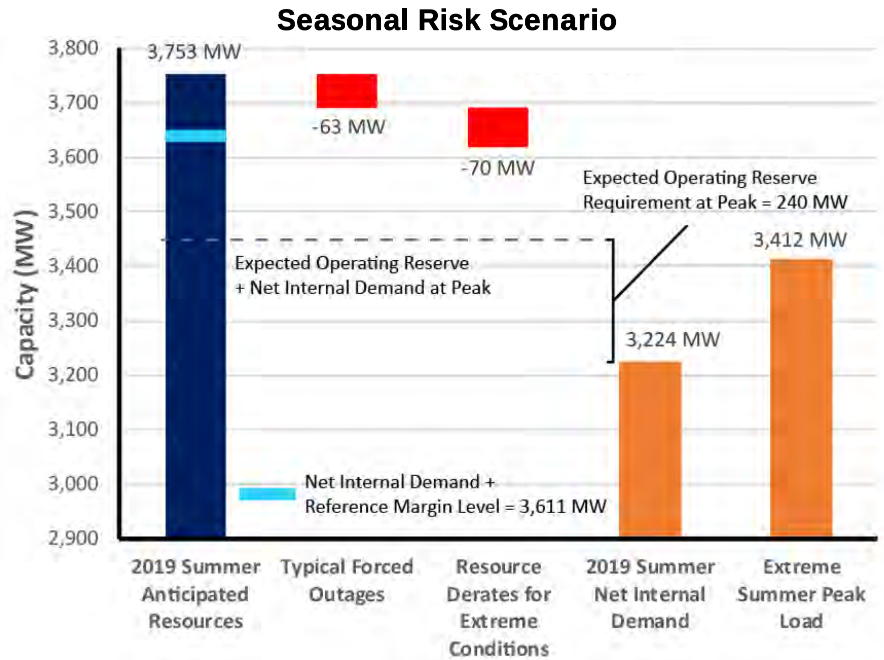
- MISO does not anticipate reliability issues during the upcoming season for typical resource outages and load. MISO studied the summer system reliability under various resource outage and load scenarios. MISO held a summer readiness workshop with its members on April 23, 2019, to prepare for summer operations.
- MISO worked with entities in the SERC Region to develop an operating procedure to address potential issues that may result from high MISO north and south transfers. These transfers between MISO operating areas can cause entities in other Regions to experience loop flows that can impact system operations.
- MISO's Load Modifying Resource (LMR) FERC filing is expected to provide MISO's operators with greater access to the existing capabilities of LMRs. Enhancements include requiring LMR units to operate to their existing capability and added processes to schedule LMRs in anticipation of emergency conditions.

MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation that provides electricity to about 573,000 customers throughout Manitoba and natural gas service to about 279,000 customers in various communities throughout Southern Manitoba. The Province of Manitoba has a population of about 1.3 million people 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.





The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MRO-Manitoba determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** All-time highest peak load
- **Outages:** Based on historical operating experience
- **Extreme Derates:** Thermal units derated for extreme temperature where appropriate

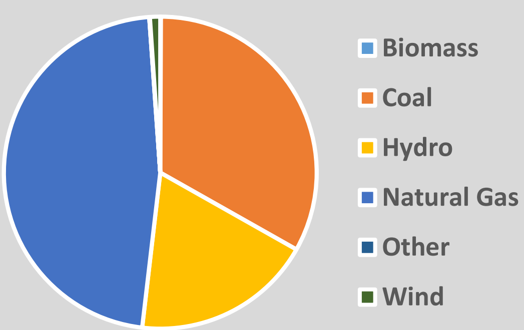
MRO-Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,237	3,224	-0.4%
Demand Response: Available	0	0	0.0%
Net Internal Demand	3,237	3,224	-0.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,288	5,161	-2.4%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	-1,342	-1,408	4.9%
Anticipated Resources	3,946	3,753	-4.9%
Existing-Other Capacity	122.3	215	75.4%
Prospective Resources	4,068	3,968	-2.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	21.9%	16.4%	-5.5
Prospective Reserve Margin	25.7%	23.1%	-2.6
Reference Margin Level	12.0%	12.0%	0.0

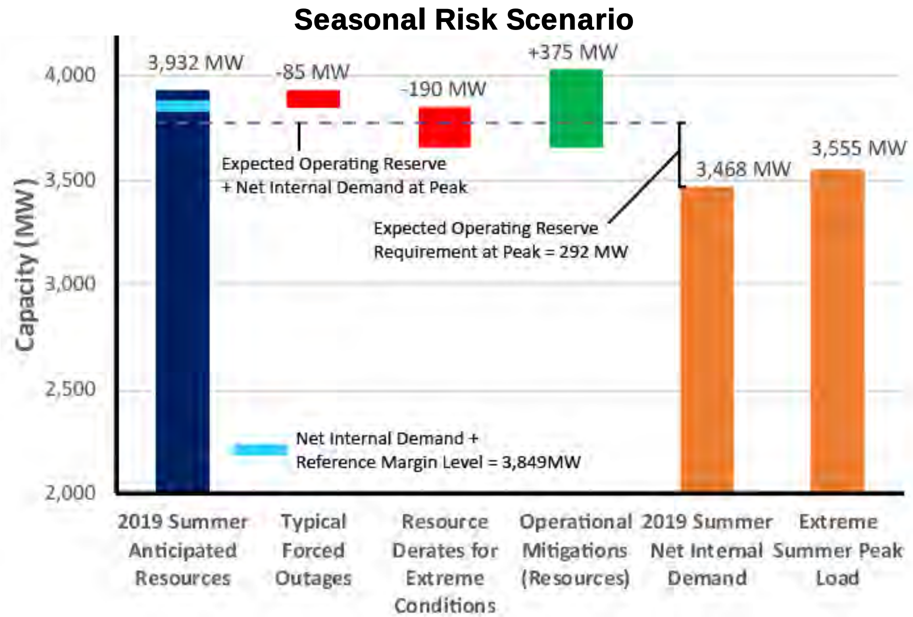
Highlights

- There are no emerging reliability issues for the upcoming season in the Manitoba Hydro assessment area.
- Manitoba Hydro completed and commissioned the third HVdc line and placed it into service in July 2018. This addition significantly increased the system reliability by introducing an additional corridor for transmission of power generated by the bulk of Manitoba Hydro's generation in northern Manitoba to Southern Manitoba where the majority of the load is located.
- Reservoirs are at adequate storage levels and capable of supplying through design drought conditions.

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.





The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MRO-SaskPower determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under typical scenarios. Operating mitigations would be needed to meet reserve requirements in extreme outages and peak loads.

Scenario Assumptions

- **Extreme Peak Load:** Peak load with peak lighting and industrial demand
- **Maintenance Outages:** Estimated based on average maintenance outages in Summer 2018
- **Forced Outages:** Estimated using SaskPower model
- **Extreme Derates:** Derate on natural gas units based on historic data and manufacturer data

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,426	3,553	3.7%
Demand Response: Available	85	85	0.0%
Net Internal Demand	3,341	3,468	3.8%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	4,013	3,907	-2.6%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	25	25	0.0%
Anticipated Resources	4,038	3,932	-2.6%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	4,038	3,932	-2.6%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	20.8%	13.4%	-7.4
Prospective Reserve Margin	20.8%	13.4%	-7.4
Reference Margin Level	11.0%	11.0%	0.0

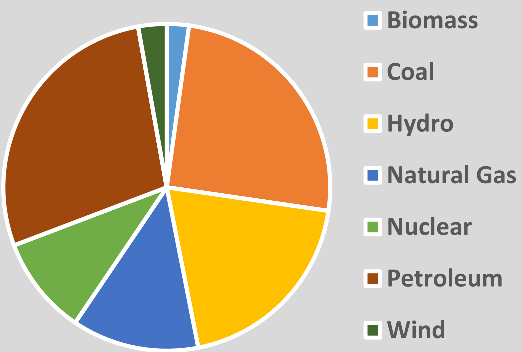
Highlights

- No reliability issues are expected for the upcoming summer season. Saskatchewan experiences peak load in winter. Reserve margin is expected to be higher than the reference reserve margin for the upcoming summer
- SaskPower conducts an annual summer season joint operating study with Manitoba Hydro, with inputs from Basin Electric Power Cooperative (North Dakota), and prepares operating guidelines for identified issues.
- In case of extreme load 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.

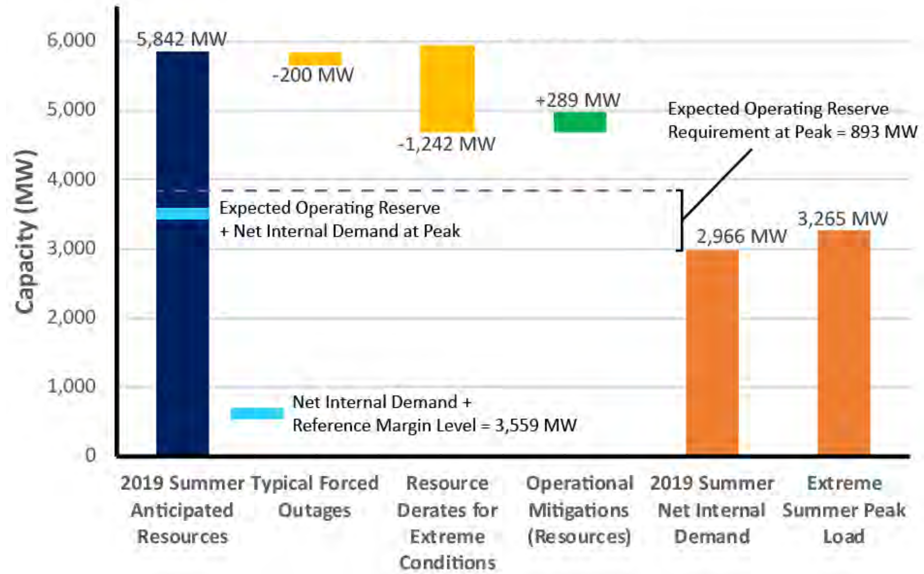
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion 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 people.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,235	3,255	0.6%
Demand Response: Available	300	289	-3.7%
Net Internal Demand	2,935	2,966	1.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,828	5,842	0.2%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	5,828	5,842	0.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,828	5,842	0.2%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	98.6%	97.0%	-1.6
Prospective Reserve Margin	98.6%	97.0%	-1.6
Reference Margin Level	20.0%	20.0%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-Maritimes determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

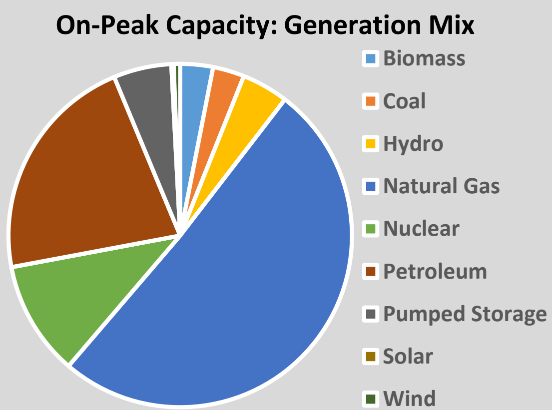
- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** An extreme, low-likelihood scenario is used whereby thermal units are derated for extreme temperature and all wind unit capacity is unavailable

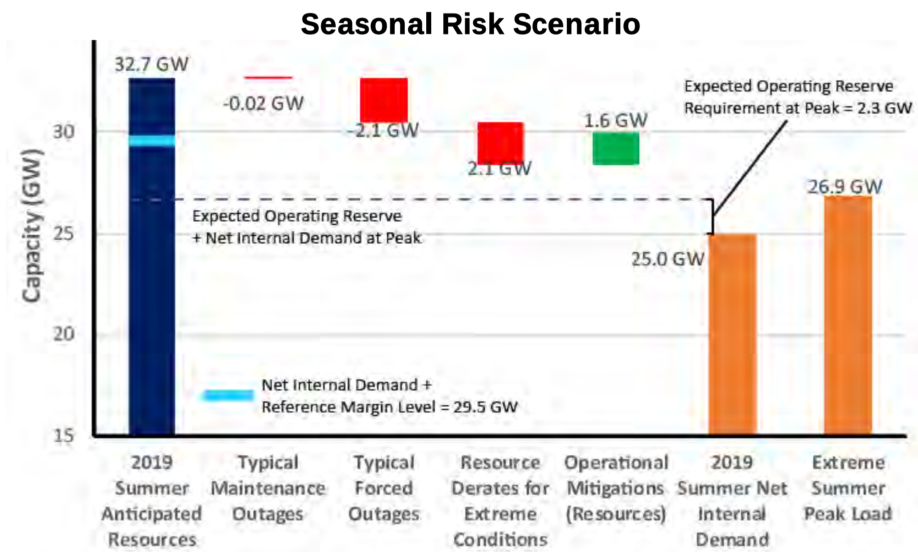
Highlights

- 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 the summer operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.

NPCC-New England

ISO New England (ISO-NE) Inc. is a Regional Transmission Organization that serves 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, and it also administers the area's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.





NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	25,729	25,323	-1.6%
Demand Response: Available	408	340	-16.7%
Net Internal Demand	25,321	24,983	-1.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	30,460	30,144	-1.0%
Tier 1 Planned Capacity	0	1,185	-
Net Firm Capacity Transfers	1,468	1,328	-9.5%
Anticipated Resources	31,928	32,657	2.3%
Existing-Other Capacity	421	704	67.2%
Prospective Resources	32,349	33,361	3.1%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	26.1%	30.7%	4.6
Prospective Reserve Margin	27.8%	33.5%	5.7
Reference Margin Level	16.8%	18.3%	1.5

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-New England determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Near-zero MW due to summer peaking area
- **Extreme Derates:** Based on historical forced outages and any additional reductions for fuel-supply risk
- **Operating Mitigations:** Based on ISO-NE operating procedures

Highlights

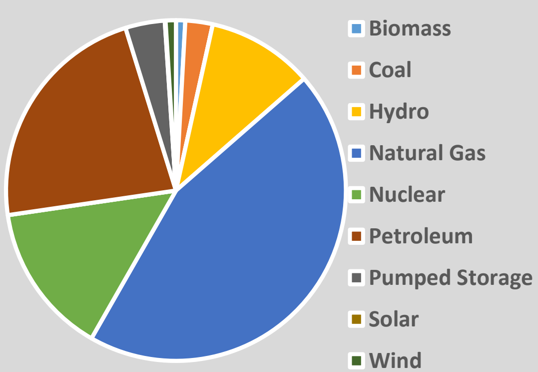
- The New England area expects to have sufficient resources to meet the 2019 summer peak demand forecast of 25,323 MW, with a corresponding projected net margin of 7,674 MW after accounting for demand response resources. This net margin is a 1,067 MW increase from the 2018 Anticipated Reserve Margin forecast. The increase can be largely attributed to new generation becoming available prior to the 2019 summer and a decrease in forecasted net demand.
- The upcoming retirement of the 674 MW Pilgrim nuclear unit is offset by additions in excess of 1,000 MW of combined cycle and combustion gas turbine generating units.
- The 2019 summer demand forecast is 406 MW (1.6%) lower than the 2018 summer forecast and takes into account the demand reductions associated with energy efficiency and behind-the-meter photovoltaic (BTM-PV) systems.
- The 18.3% Reference Margin Level is based on New England's net installed capacity requirement for the 2019–2020 commitment period, which was approved by FERC.

NPCC-New York

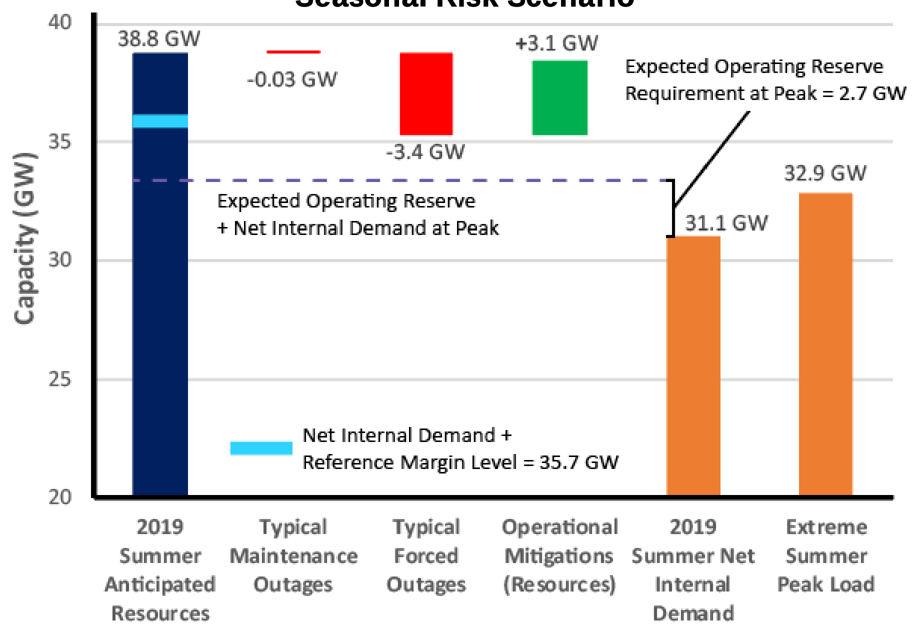
The New York Independent System Operator (NYISO) is the only Balancing Authority (NYBA) within the state of New York. NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. NYISO manages the New York State transmission grid that encompasses approximately 11,000 miles of transmission lines, more than 47,000 square miles, and serving the electric needs of 19.5 million people. New York experienced its all-time peak load of 33,956 MW in the 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 2019–2020 IRM at 17%.

On-Peak Capacity: Generation Mix



Seasonal Risk Scenario



NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	32,904	32,382	-1.6%
Demand Response: Available	1,219	1,309	7.4%
Net Internal Demand	31,685	31,073	-1.9%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	39,066	37,304	-4.5%
Tier 1 Planned Capacity	260	27	-89.6%
Net Firm Capacity Transfers	1,625	1,452	-10.7%
Anticipated Resources	40,950	38,783	-5.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	40,950	38,783	-5.3%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	29.2%	24.8%	-4.4
Prospective Reserve Margin	29.2%	24.8%	-4.4
Reference Margin Level	18.2%	15.0%	-3.2

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-New York determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Extreme Derates:** Near-zero MW due to summer peaking area
- **Forced Outages:** Based on five-year average performance
- **Operational Mitigation:** Based on operational/emergency procedures in NYISO Emergency Operations Manual

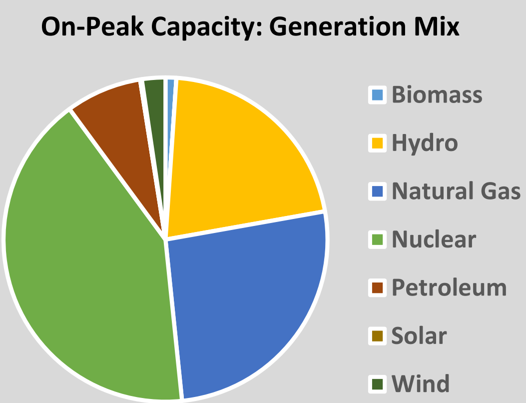
Highlights

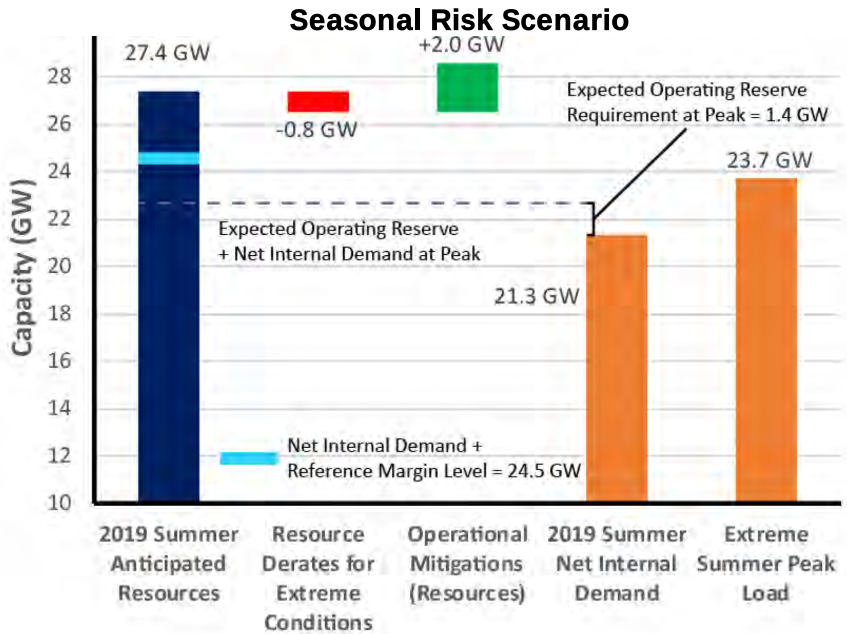
- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- High capacity factors on certain New York City peaking units could result in possible violations of their daily NOx emission limits if they were to fully respond to the NYISO dispatch signals. Significant run-time on peaking units, indicating the potential for a violation, could be the result of long duration hot weather events or loss of significant generation or transmission assets in New York City.

NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority and Reliability Coordinator for the province of Ontario. In addition to administering the area's wholesale electricity markets, the IESO plans for Ontario's future energy needs. Ontario covers more than 415,000 square miles and has a population of more than 14 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Ontario IESO treats demand response as a resource for its own assessments, while in the NERC assessment demand response is used as a load-modifier. As a result, the total internal demand, reserve margin, and Reference Margin Level values differ in IESO's reports when compared to NERC reports.





The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-Ontario determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Based on severe historic weather conditions
- **Extreme Derates:** Based on thermal unit derating curves, and historical hydro performance in low-water year
- **Operational Mitigation:** 2,000 MW imports assessed as available from neighbors

NPCC-Ontario Resource Adequacy Data

Demand, Resource, and Reserve Margin	2018 SRA	2019 SRA	2018 vs. 2019 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	22,002	22,105	0.5%
Demand Response: Available	630	790	25.4%
Net Internal Demand	21,372	21,315	-0.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	25,731	26,581	3.3%
Tier 1 Planned Capacity	23	924	>100%
Net Firm Capacity Transfers	0	-102	-
Anticipated Resources	25,754	27,403	6.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	25,754	27,403	6.4%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	20.5%	28.6%	8.1
Prospective Reserve Margin	20.5%	28.6%	8.1
Reference Margin Level	13.3%	14.9%	1.6

Highlights

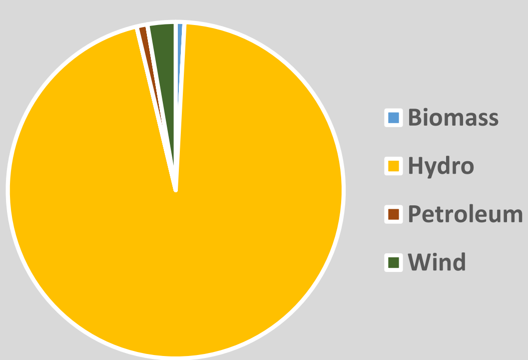
- There are sufficient resources to maintain the reliability of Ontario's electricity system under normal weather conditions for Summer 2019.
- The IESO recently revised its outage approval methods and will evaluate outages using its extreme weather scenario with only firm resources and up to 2,000 MW of imports.
- Driven by the need to enhance planning transparency and help market participants make more informed decisions and investments, the IESO has renewed its approach to planning with a particular emphasis on its commitment to regular sharing of information with stakeholders. As a first step in delivering on this commitment, and helping generators and transmitters plan for and schedule outages, the IESO now extends its 18-month outage planning horizon to five years twice yearly.

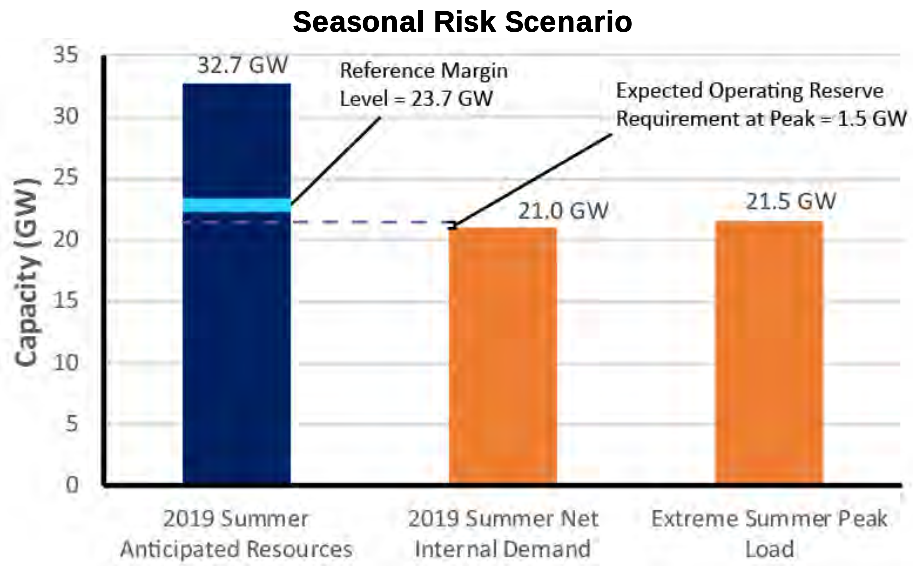
NPCC-Québec

The Québec Assessment Area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight million.

Québec is one of the four 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 Capacity: Generation Mix





NPCC- Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	20,534	21,005	2.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	20,534	21,005	2.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	34,014	34,303	0.8%
Tier 1 Planned Capacity	0	28	-
Net Firm Capacity Transfers	-1,829	-1,663	-9.1%
Anticipated Resources	32,185	32,667	1.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	32,185	32,667	1.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	56.7%	55.5%	-1.2
Prospective Reserve Margin	56.7%	55.5%	-1.2
Reference Margin Level	12.6%	12.8%	0.2

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. NPCC-Québec determined the adjustments to peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Anticipated Resources:** Includes planned generator outages, deratings, bottling, historic hydroelectric reduction and 100% reduction in installed wind generation capacity

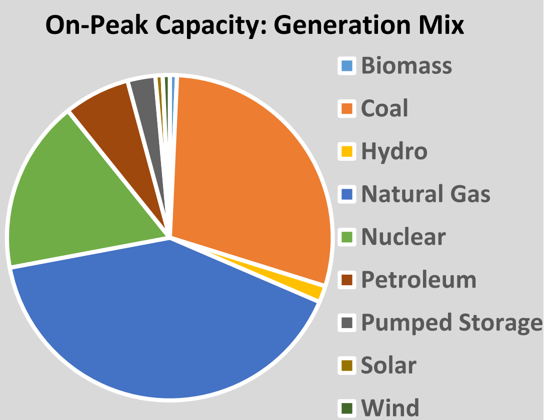
Highlights

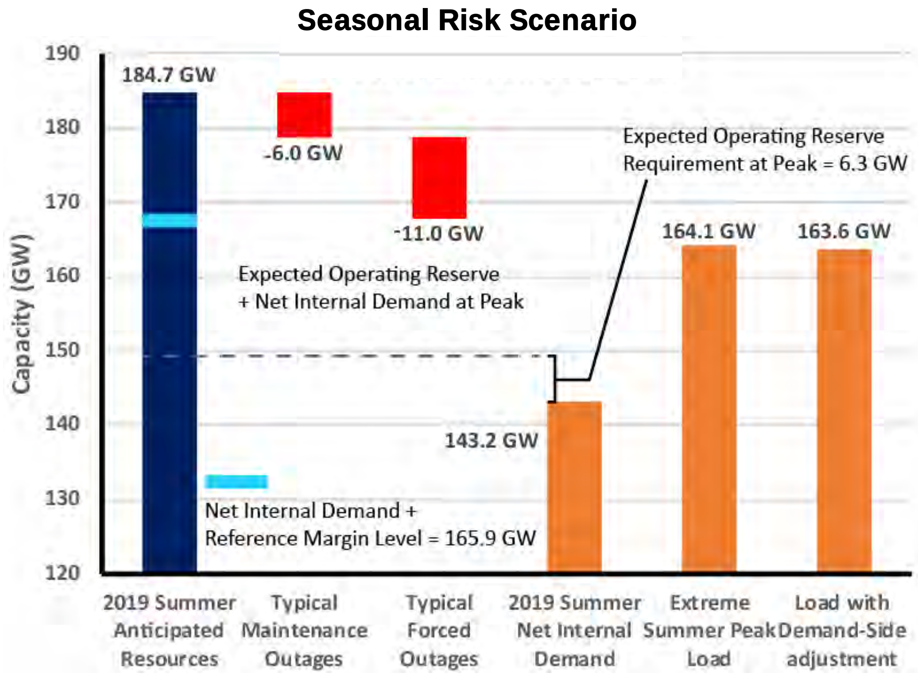
- No issues are anticipated for the summer operating period since the system is winter peaking.
- A new 735 kV line is expected to be commissioned in May 2019 to meet NERC Reliability Standards and will provide more flexibility to operators.
- The Québec area expects to be able to provide assistance to neighboring areas if needed, up to the transfer capability available.

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.





PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	152,108	151,358	-0.5%
Demand Response: Available	9,095	8,154	-10.3%
Net Internal Demand	143,013	143,204	0.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	185,440	181,013	-2.4%
Tier 1 Planned Capacity	0	2,200	-
Net Firm Capacity Transfers	4,419	1,535	-65.3%
Anticipated Resources	189,859	184,748	-2.7%
Existing-Other Capacity	0	0	0
Prospective Resources	189,859	184,748	-2.7%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	32.8%	29.0%	-3.8
Prospective Reserve Margin	32.8%	29.0%	-3.8
Reference Margin Level	16.1%	15.9%	-0.2

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. PJM determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Approximate values based on review of previous summer peak periods

Highlights

- The PJM reserve margin for this summer is 29.0% with a requirement of 15.9%. With this level of capacity, PJM has not identified any emerging reliability issues regarding resource adequacy.
- Ohio Valley Electric Cooperative (OVEC) moved from MISO into PJM in December 2018. OVEC has two large generating plants that have moved from having significant transfers into PJM to now being part of the PJM market dispatch.

SERC

SERC's assessment areas are traditionally summer-peaking and cover approximately 72,000 circuit miles and serve a population estimated at 23 million.

For NERC's assessment, the Region is divided into three assessment areas: SERC- E, SERC-C, and SERC-SE. The assessment areas include 12 Balancing Authorities: Cube Hydro Carolinas LLC, Associated Electric Cooperative, Inc. (AECI), Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric and Kentucky Utilities (LG&E/ KU)), PowerSouth Energy Cooperative (PowerSouth), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (SCPSA), Southern Company Services, Inc. (SOCO), Southeastern Power Administration (SPA), and Tennessee Valley Authority (TVA).

SERC Resource Adequacy Data

Demand, Resource, and Reserve Margins	SERC-E	SERC-C	SERC-SE	2018 SRA SERC Total	2019 SRA SERC Total	2018 vs. 2019 SRA
Demand Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Total Internal Demand (50/50)	43,704	40,781	47,311	131,994	131,796	-0.2%
Demand Response: Available	1,054	1,964	2,293	4,640	5,311	14.5%
Net Internal Demand	42,650	38,817	45,018	127,354	126,485	-0.7%
Resource Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Existing-Certain Capacity	50,976	50,391	61,182	161,532	162,549	0.6%
Tier 1 Planned Capacity	0	0	458	1,875	458	-75.6%
Net Firm Capacity Transfers	455	301	-1,905	-3,133	-1,150	-63.3%
Anticipated Resources	51,431	50,692	59,734	160,274	161,857	1.0%
Existing-Other Capacity	852	4,060	289	2,361	5,200	120.2%
Prospective Resources	52,282	54,752	60,023	162,635	167,057	2.7%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	20.6%	30.6%	32.7%	25.9%	28.0%	2.1
Prospective Reserve Margin	22.6%	41.1%	33.3%	27.7%	32.1%	4.4
Reference Margin Level	13.15%	13.15%	13.15%	15.00%	13.15%	-1.85

Highlights

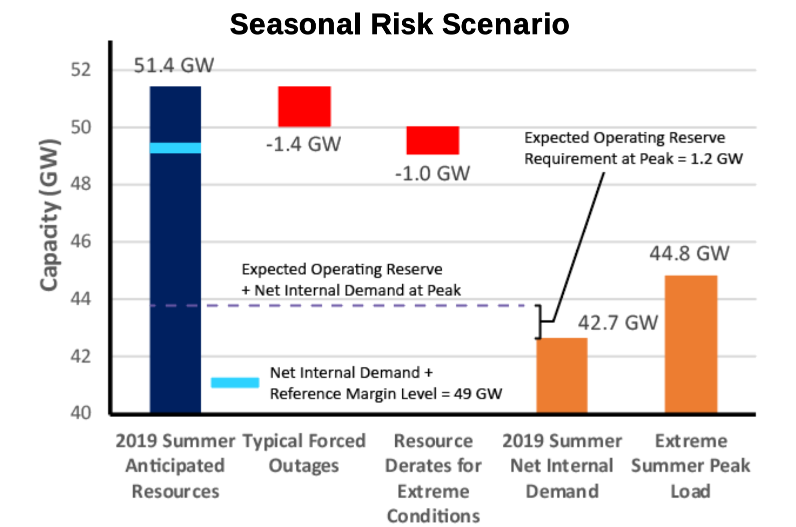
- To date, there are no significant reliability risks expected for the 2019 summer season in the SERC Region.
- SERC continues to prepare for the integration of entities within FRCC. Both FRCC and the SERC Region are coordinating activities to ensure a successful transition of the new registered entities into the SERC Region's reliability programs and processes. For more information, visit the FRCC RE Integration webpage.[9]
- To align with SERC's subregional naming convention in its regional studies and assessments, the SERC North Assessment Area was changed to SERC Central Assessment Area in NERC Reliability Assessments.
- SERC Southeast entities have experienced loop flows from a high regional transfers between MISO North and MISO South. As a result, the impacted utilities along with MISO developed an operating procedure to address potential reliability issues that could result from high MISO regional transfers.

Charts

The charts on the next page provide potential summer peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. SERC determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the **Seasonal Risk Scenario Chart Description** for more information about the charts.

[9] See http://www.serc1.org/outreach/frcc-re-integration

SERC-E



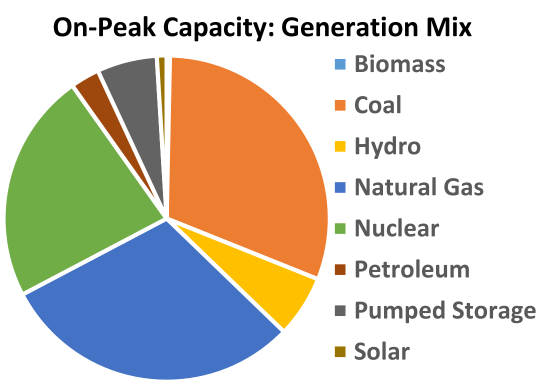
Risk Scenario Summary

Observation:

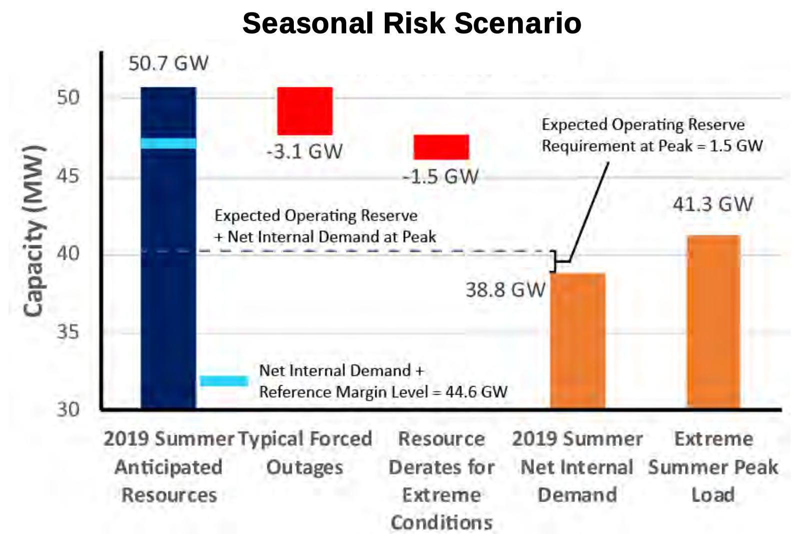
Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic



SERC-C



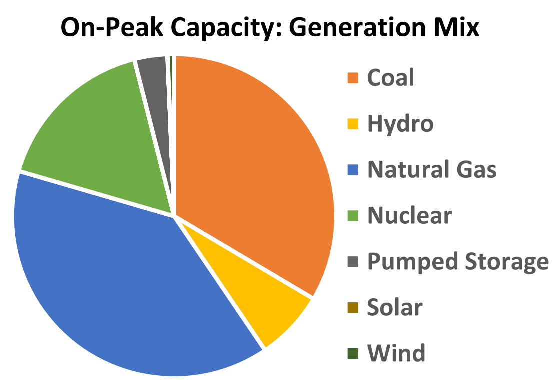
Risk Scenario Summary

Observation:

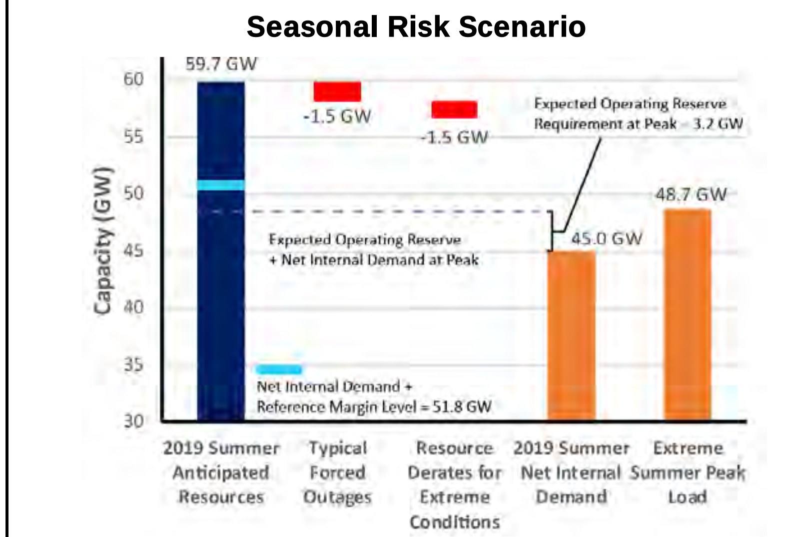
Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic



SERC-SE



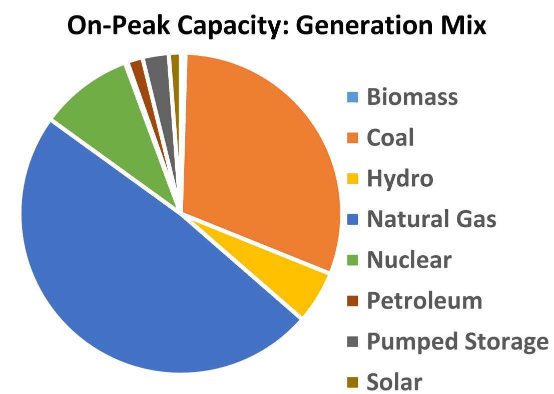
Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under studied scenarios

Scenario Assumptions

- **Extreme Peak Load:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistical level
- **Outages:** Based on historical data
- **Extreme Derates:** Based on 2018 SERC Probabilistic Assessment, equal to or exceeding a 90/10 statistic

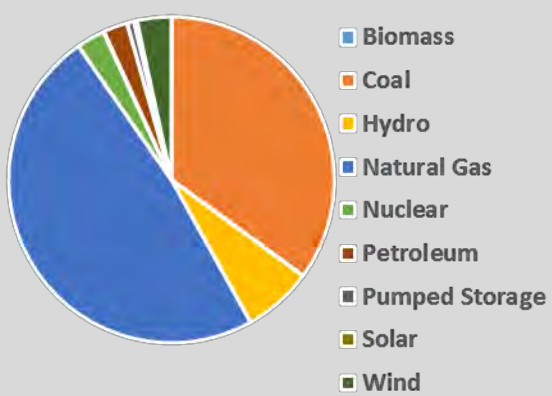


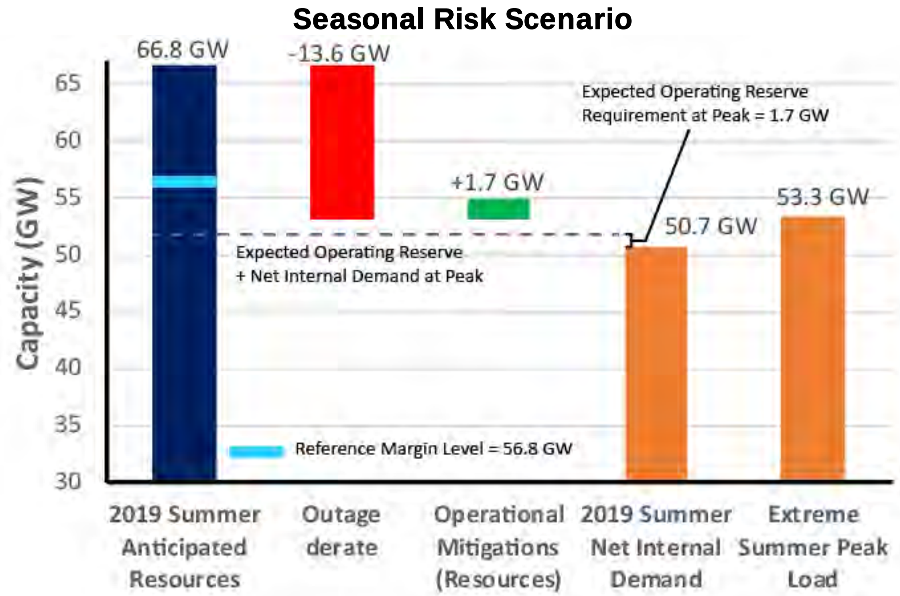
SPP

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 WECC. 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 people.

On-Peak Capacity: Generation Mix





The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. SPP determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Seasonal Risk Scenario Chart Description for more information about this chart.

Risk Scenario Summary

Observation: Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** A derate for forced outages and performance in extreme weather based on historical data

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	52,554	51,520	-2.0%*
Demand Response: Available	867	835	-3.8%
Net Internal Demand	51,687	50,685	-1.9%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	67,649	67,960	0.5%
Tier 1 Planned Capacity	779.85	64	-91.8%
Net Firm Capacity Transfers	19	-1,244	-
Anticipated Resources	68,447	66,780	-2.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	68,447	66,780	-2.4%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	32.4%	31.8%	-0.6
Prospective Reserve Margin	32.4%	31.8%	-0.6
Reference Margin Level	12.0%	12.0%	0.0

* In 2018, Total Internal Demand was calculated on a non-coincident peak basis, resulting in higher demand calculations compared to coincident peak basis used for the 2019 SRA.

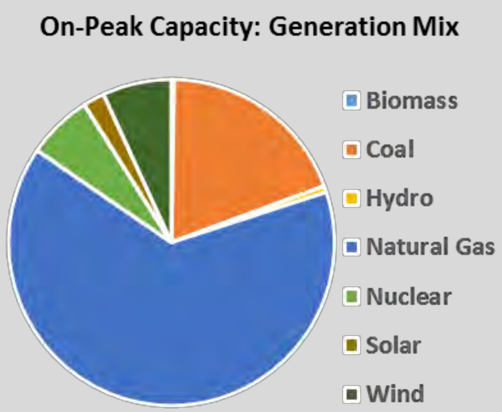
Highlights

- SPP does not anticipate any emerging reliability issues impacting the area for the 2019 summer season.
- SPP has experienced mid-range forecast error uncertainty in wind forecasts as the penetration of wind generation increases. This is not an issue if the error is short lived, but if the error continues throughout the day it can lead to short-term supply scarcity. Within SPP, a team is developing mitigation to ensure appropriate ramp product is available on a daily basis.

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 Region 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 Region.



Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2018 SRA**	**2019 SRA**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	72,756	74,853	2.9%
Demand Response: Available	2,301	2,227	-3.2%
Net Internal Demand	70,455	72,626	3.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	76,654	77,482	1.1%
Tier 1 Planned Capacity	738.95	607	-17.9%
Net Firm Capacity Transfers	753	721	-4.2%
Anticipated Resources	78,146	78,810	0.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	78,146	78,810	0.9%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	10.9%	8.5%	-2.4
Prospective Reserve Margin	10.9%	8.5%	-2.4
Reference Margin Level	13.75%	13.75%	0.0

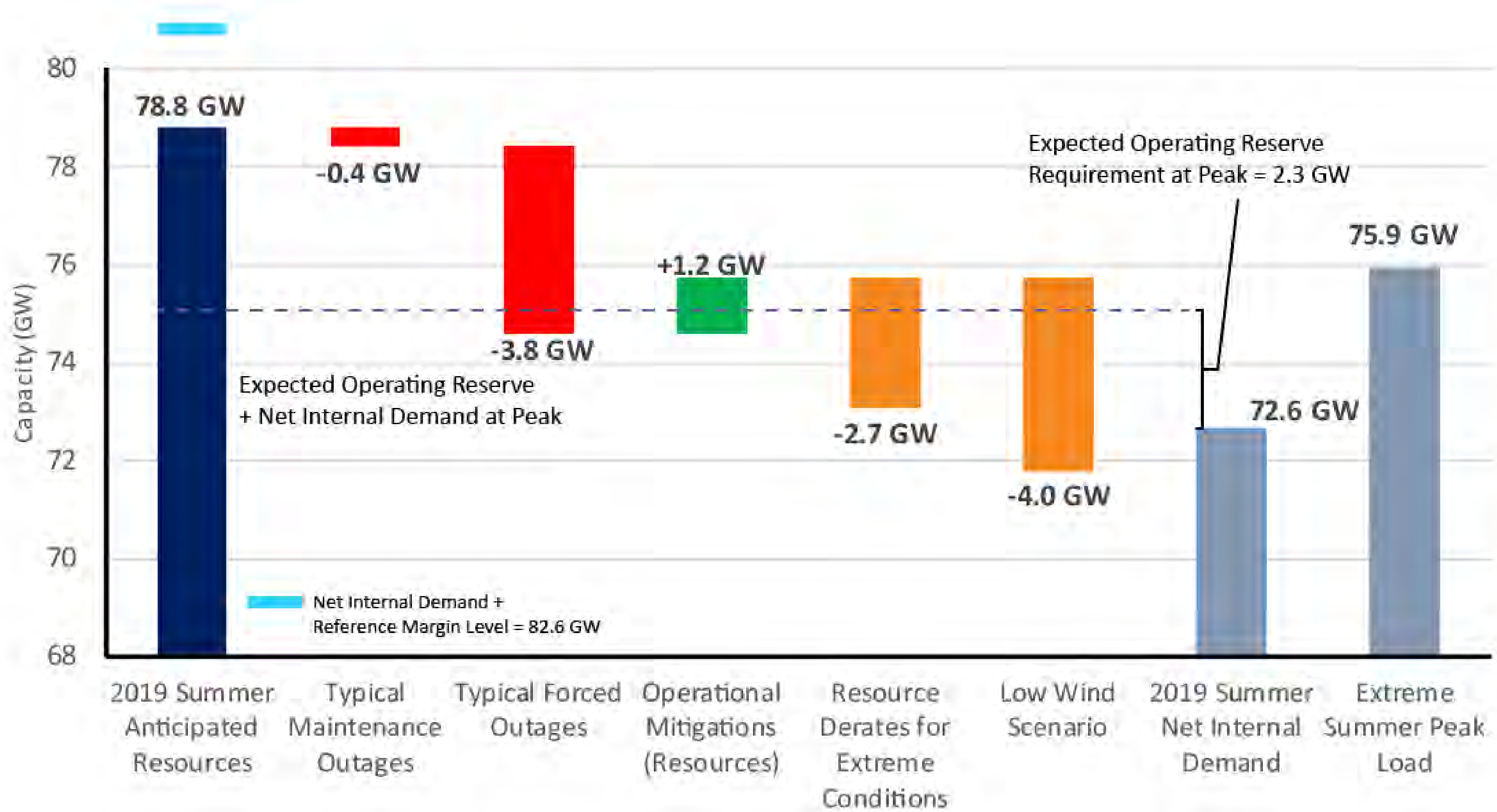
Highlights

- Despite growth in anticipated resources relative to last summer, even higher expected summer peak demand, combined with delays in planned generation projects and the announced mothballing of a 470 MW coal-fired unit, are expected to result in a tighter reserve margin for the upcoming summer.
- Notable transmission improvements include a new 250 MVAr STATCOM expected to be in-service prior to summer in the Far West Texas region to support the rapid growth of oil and gas production load in the Permian Basin. Additionally, a new 345 kV line in Central Texas will be energized in the spring to support the San Antonio area.
- There are no known transmission reliability, fuel supply, or essential reliability service procurement issues projected for the upcoming season. However, delays or cancellations of planned transmission expansion projects, if they occur, may contribute to potential localized reliability concerns.

Charts

The chart on the next page provide potential summer peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. ERCOT determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the Seasonal Risk Scenario Chart Description for more information about the chart.

Seasonal Risk Scenario



The table on page 26 and the chart above provide potential summer peak demand and resource condition information. The table presents a standard seasonal assessment and comparison to the previous year's assessment. The chart presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions.

Risk Scenario Summary

Observation:

Operating Mitigations and Energy Emergency Alerts may be needed under peak and extreme conditions studied.

Scenario Assumptions (see Table 1 on Page 9 for detailed discussion)

- **Extreme Peak Load:** Based on 2011 historic summer peak load
- **Outages:** A derate for maintenance and forced outages based on the past three year summer periods
- **Operational Mitigations.** Additional resources (e.g., switchable generation resources, additional imports, and voltage reduction) to support maintaining operating reserves, not already counted in SRA reserve margins.

WECC

WECC is responsible for coordinating and promoting BES 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 BES. 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 states in between. The WECC assessment area is divided into six subregions: 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 subregional 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-US**	**RMRG**	**SRSG**	**2018**	**2019**	**2018 vs. 2019 SRA**
Demand Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Total MW**	**Total MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,111	8,432	52,929	47,619	12,636	23,415	154,256	156,142	1.2%
Demand Response: Available	0	0	957	614	225	368	3,569	2,164	-39.4%
Net Internal Demand	11,111	8,432	51,972	47,006	12,411	23,047	150,687	153,979	2.2%
Resource Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,560	9,746	61,806	60,056	16,627	31,413	184,981	194,208	5.0%
Tier 1 Planned Capacity	43	152	1,818	1,007	257	684	1,098	3,961	>100%
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0.0%
Anticipated Resources	14,603	9,898	63,624	61,063	16,884	32,097	186,079	198,169	6.5%
Existing-Other Capacity	0	0	0	0	0	0	0	0	0.0%
Prospective Resources	14,603	9,898	63,624	61,063	16,884	32,097	186,079	198,169	6.5%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	31.4%	17.4%	22.4%	29.9%	36.0%	39.3%	23.5%	28.7%	5.2
Prospective Reserve Margin	31.4%	17.4%	22.4%	29.9%	36.0%	39.3%	23.5%	28.7%	5.2
Reference Margin Level	10.0%	10.0%	12.0%	20.0%	17.0%	15.0%	15.4%	15.4%	0.0

Highlights

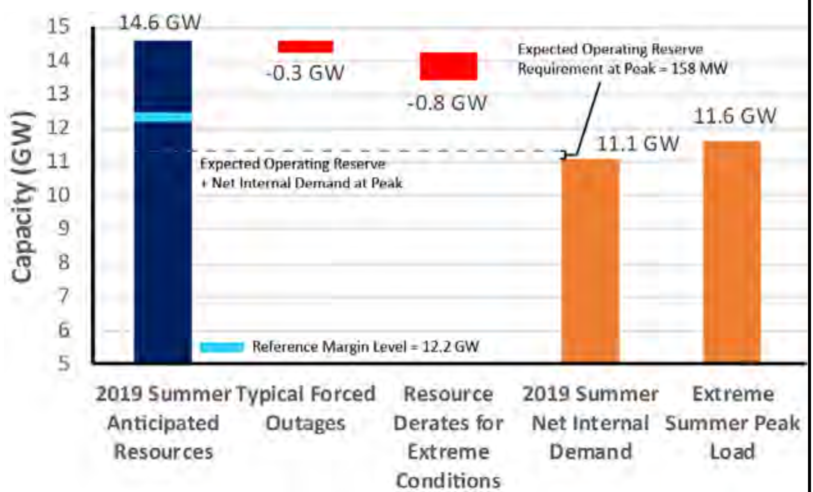
- The existing and Anticipated Reserve Margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season.
- WECC and NERC are monitoring the transition of Reliability Coordinator (RC) responsibilities in the Western Interconnection as Peak RC winds down toward disestablishment at the end of 2019. NERC-certified RCs are scheduled to assume responsibilities in California (July 1) and British Columbia (September 2). All other areas will complete transition prior to December 31. Certification site visits, shadow-operating periods with Peak RC, and WECC-sponsored RC transition activities are being implemented to manage reliability risks.
- Inventories of the Aliso Canyon natural gas storage facility remain an item of focus for reliability within the Western Interconnection. This condition is being closely monitored by the CAISO, SoCal Gas, and WECC's Situational Awareness group.
- Above-average snowpack levels and the anticipated abundance of hydroelectric generation in California may be used to displace generation from natural-gas-fired units, freeing up more natural gas for Southern California if fuel availability becomes an issue.
- Localized short-term operational issues may occur due to wildfires, if seasonal wildfire predictions are accurate. Due to the widely dispersed nature of the transmission system, outages due to wildfires are generally not widespread.

Charts

The charts on the next page provide potential summer peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. WECC entities determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized on the next page. See the Seasonal Risk Scenario Chart Description for more information about the charts.

WECC-Alberta

Seasonal Risk Scenario



Risk Scenario Summary

Observation:

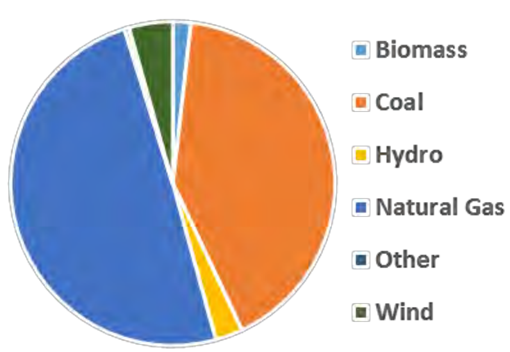
Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data

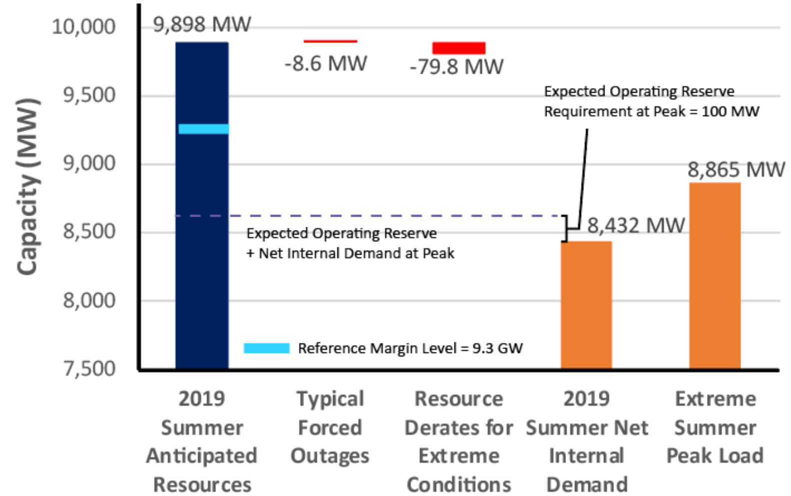
  Extreme Derates: Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-British Columbia

Seasonal Risk Scenario



Risk Scenario Summary

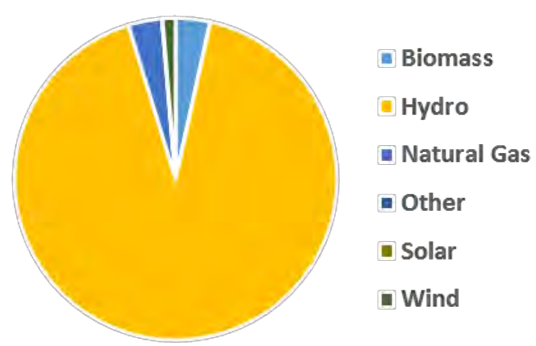
Observation:

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

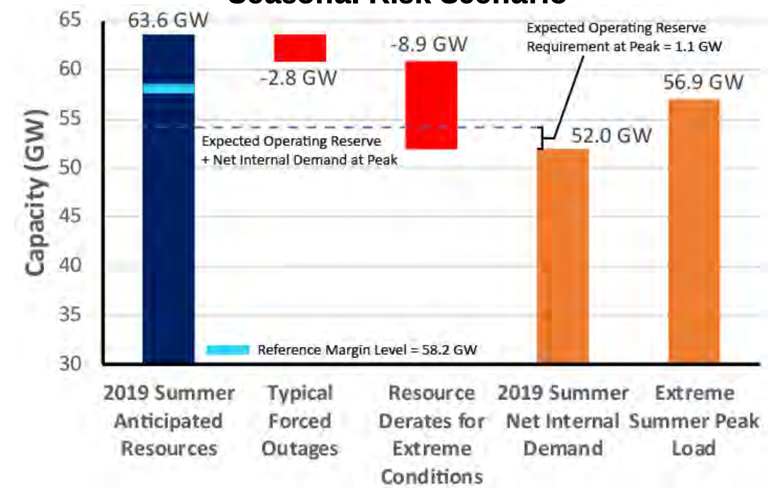
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-California/Mexico

Seasonal Risk Scenario



Risk Scenario Summary

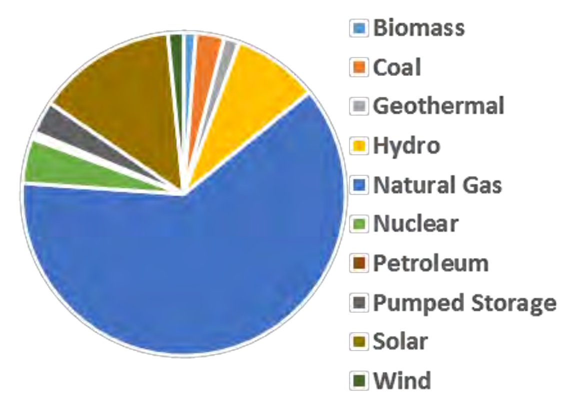
Observation:

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

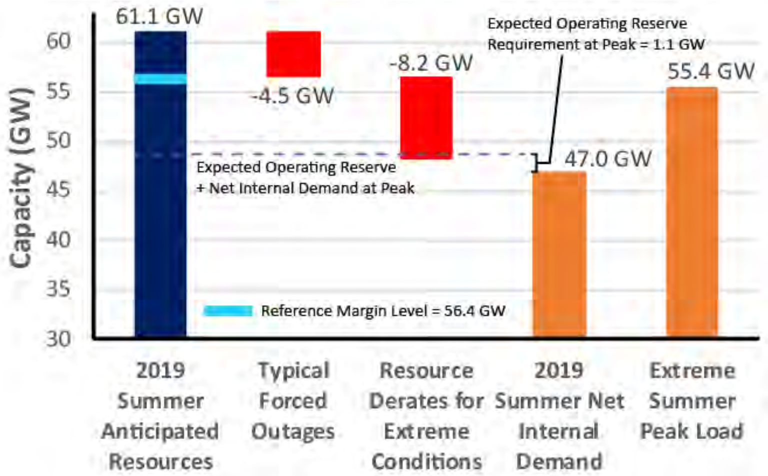
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-Northwest Power Pool

Seasonal Risk Scenario



Risk Scenario Summary

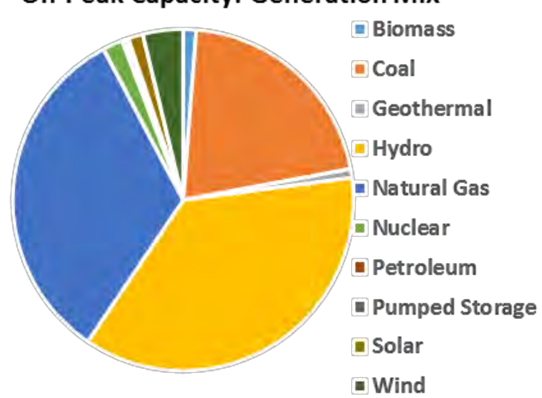
Observation:

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

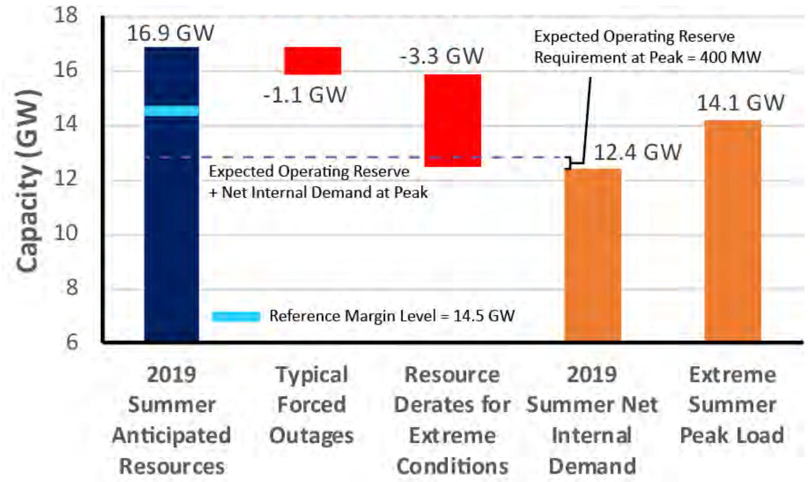
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-Rocky Mountain Reserve Sharing Group

Seasonal Risk Scenario



Risk Scenario Summary

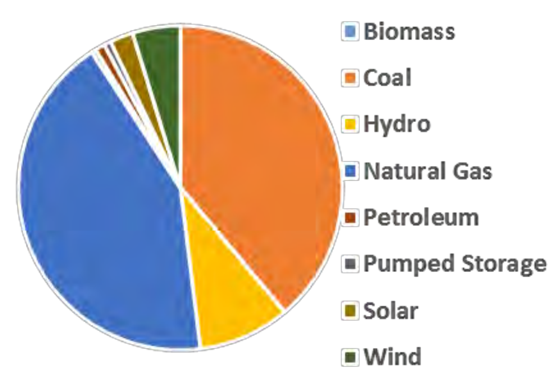
Observation:

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

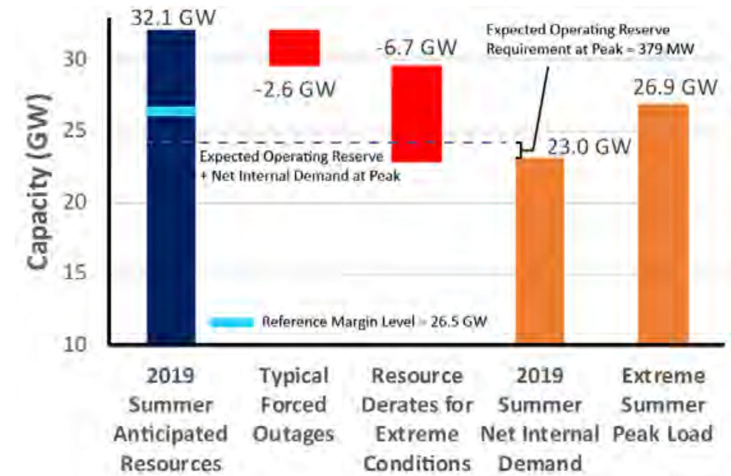
- **Extreme Peak Load:** Based on 90/10 demand forecast
- **Forced Outages:** Based on historical data
- **Extreme Derates:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation Mix



WECC-Southwest Reserve Sharing Group

Seasonal Risk Scenario



Risk Scenario Summary

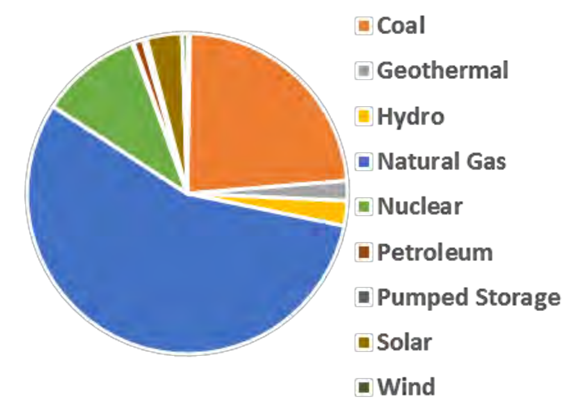
Observation:

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:** Derates for thermal, wind, and solar were developed using the tenth percentile availability curves for the respective resources for the assessment area peak hour

On-Peak Capacity: Generation 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.
- *2018 Long-Term Reliability Assessment* data has been used for most of this 2019 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[10], or total internal demand, for the summer and winter of each year.[11]
- Total internal demand projections are based on normal weather (50/50 distribution[12]) and are provided on a coincident[13] 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 units, or portions of generating units, that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement (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**: includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: 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 summer or summer season but do not meet the requirements of existing-certain.

Reserve Margin Definitions

Reserve Margins: 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, shown as a percentage:

[10] *Glossary of Terms* Used in NERC Reliability Standards

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

[12] 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.

[13] Coincident: The sum of two or more peak loads that occur in the same hour. Noncoincident: The sum of two or more peak loads on individual systems that do not occur in the same time interval. 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

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 Summer Anticipated Resources (from the Resource Adequacy Data table). The two orange columns at the right show two demand scenarios: normal peak net internal demand from the Resource Adequacy Data table and an extreme summer peak demand, both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the Summer Anticipated Resources, such as the following:

- Reductions for typical generation outages (maintenance and forced, not already accounted for in Summer 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 resulting 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 summer 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 summer peak demand. Because such extreme scenario analysis depicts the cumulative impact resulting from the occurrence of multiple low-probability events, the overall likelihood of the scenario is very low.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2020 Summer Reliability Assessment

June 2020

Table of Contents

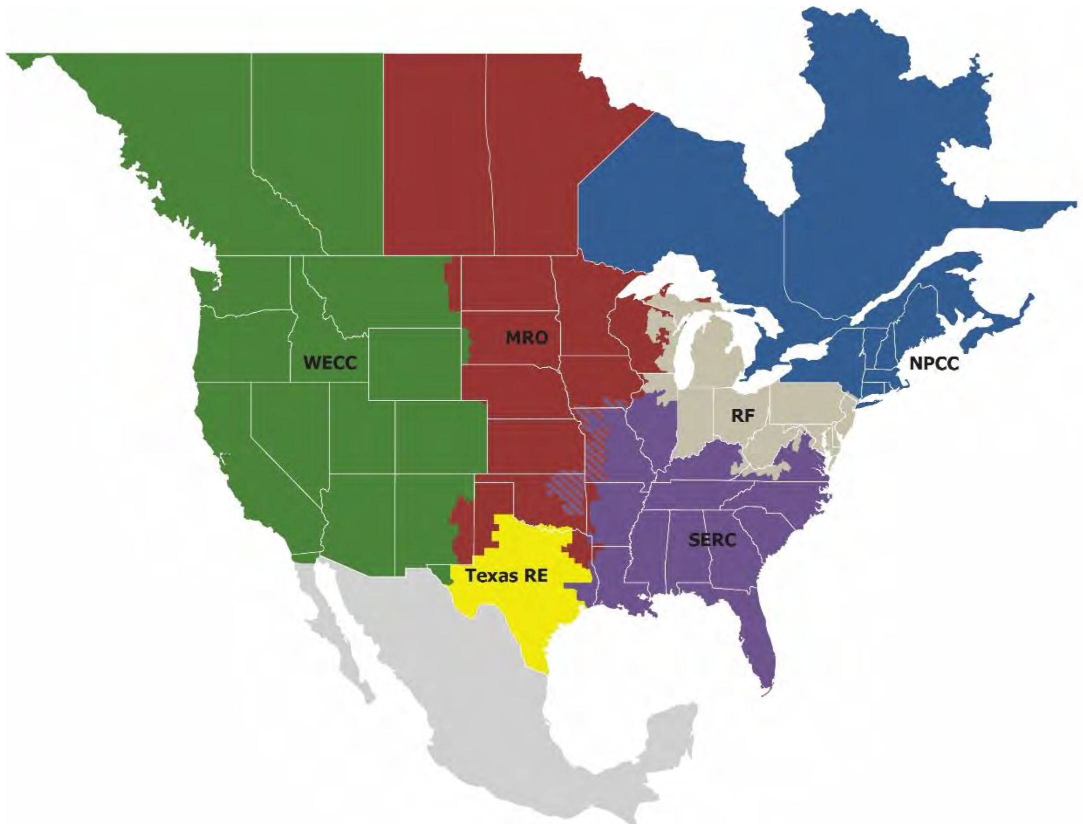
Preface

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 divided into 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 Region while associated Transmission Owners/Operators participate in another.



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

About this Report

NERC's *2020 Summer Reliability Assessment* (SRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the SRA 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 Regions, and NERC staff. This report 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. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

In April 2020, NERC published its *Special Report Pandemic Preparedness and Operational Assessment: Spring 2020* to advise electricity stakeholders about elevated risk to electric reliability as a result of the global health crisis.[1] NERC continues to assess risks to the reliability and security of the BPS from the global health crisis and reports on industry actions and preparedness in this SRA.

[1] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Pandemic_Preparedness_and_Op_Assessment_Spring_2020.pdf

Findings

NERC's annual SRA covers the Summer 2020 (June–September) period. This assessment provides an evaluation of resource and transmission system adequacy necessary to meet projected summer peak demands. In addition to assessing resource adequacy, the SRA monitors and identifies potential reliability issues of interest and regional topics of concern. In 2020, there is heightened uncertainty in demand projections stemming from the progression of the coronavirus (COVID-19) pandemic and the response of governments, society, and the electricity industry. The following key findings represent NERC's independent evaluation of electric generation and transmission capacity as well as potential operational concerns that may need to be addressed for the upcoming summer:

- **Sufficient capacity resources are expected to be in-service for the upcoming summer.** In all areas, with the exception of ERCOT, the Anticipated Reserve Margin meets or surpasses the Reference Margin Level, indicating that planned resources in these areas are adequate to manage risk of a capacity deficiency under normal conditions.[2] Assessment areas are prepared to meet potential peak demand with or without pandemic-related demand reductions. Should pandemic related restrictions continue through the summer, peak demand is expected to be lower than forecast.
    - **Texas RE-ERCOT**. Projections for increased peak demand in ERCOT indicate the potential for energy emergency alerts (EEAs) during summer peak periods. Prior to the arrival of COVID-19 and the resulting mitigations that have impacted electricity demand, ERCOT planners were expecting similarly tight operating conditions to those faced in Summer 2019. The ERCOT Anticipated Reserve Margin has risen from 8.5% in Summer 2019 to 12.9% for the upcoming summer. The increase in reserve margin is driven by the addition of over 1.9 GW of on-peak resource capacity. ERCOT's forecast of peak demand for Summer 2020 is also forecasted to grow in 2020, but higher-growth projections have been tempered in recent months by COVID-19 economic impacts. The potential for EEAs and operating mitigation at peak load remains.
- **Maintenance and preparations for summer operations impacted by pandemic.** As summer peak operating season approaches each year, generator and transmission owners and operators engage in extensive preparations, including preventive maintenance, supply stocking, and training programs. However, many normal efforts have been impinged by the global pandemic. To avoid the risk of failing to complete maintenance on-time, some owners and operators have deferred or cancelled preseason maintenance in response to pandemic-related issues. Monitoring the progress of ongoing efforts to prepare staff and equipment for summer will be important to ensuring the availability of anticipated resources to meet electricity demand. Furthermore, system operators must be prepared to address demand forecast uncertainty and potentially challenging operating conditions as a result of low demand on the system.
- **Protecting critical electric industry workforce during the COVID-19 pandemic remains a priority for reliability and resilience.** System and generation plant operators have implemented operating postures and personnel restrictions prescribed by their pandemic plans in order to protect essential personnel and support reliable operations. Many of these measures will need to be maintained for the foreseeable future. There is a continuing risk that control centers or plants could be temporarily shut down if a significant number of operators or plant employees test positive for COVID-19 despite preparedness efforts. When relaxations can be implemented, operators will likely need to stay postured to return to heightened protections in response to dynamic public health conditions.
- **Late-summer wildfire season in western United States and Canada poses risk to BPS reliability.** Government agencies warn of the potential for above-normal wildfire risk beginning as early as June in parts of the Western United States as well as Central and Western Canada.[3] Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

[2] For more information, see the description of the "Reference Margin Level" in the **Data Concepts and Assumptions** section of this report or refer to NERC's *Long-term Reliability Assessment*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf
[3] See North American Seasonal Fire Assessment and Outlook, April 2020: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

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 forecasted peak demand.[4] Large year-to-year changes in anticipated resources or forecasted peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. Other than in ERCOT, all assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for Summer 2020 as shown in the Figure 1.

Although the pandemic introduces significant uncertainty into demand and some risk to generation resource availability, as discussed in the following section, the projections below provide indication that adequate resources are available to meet peak demand.

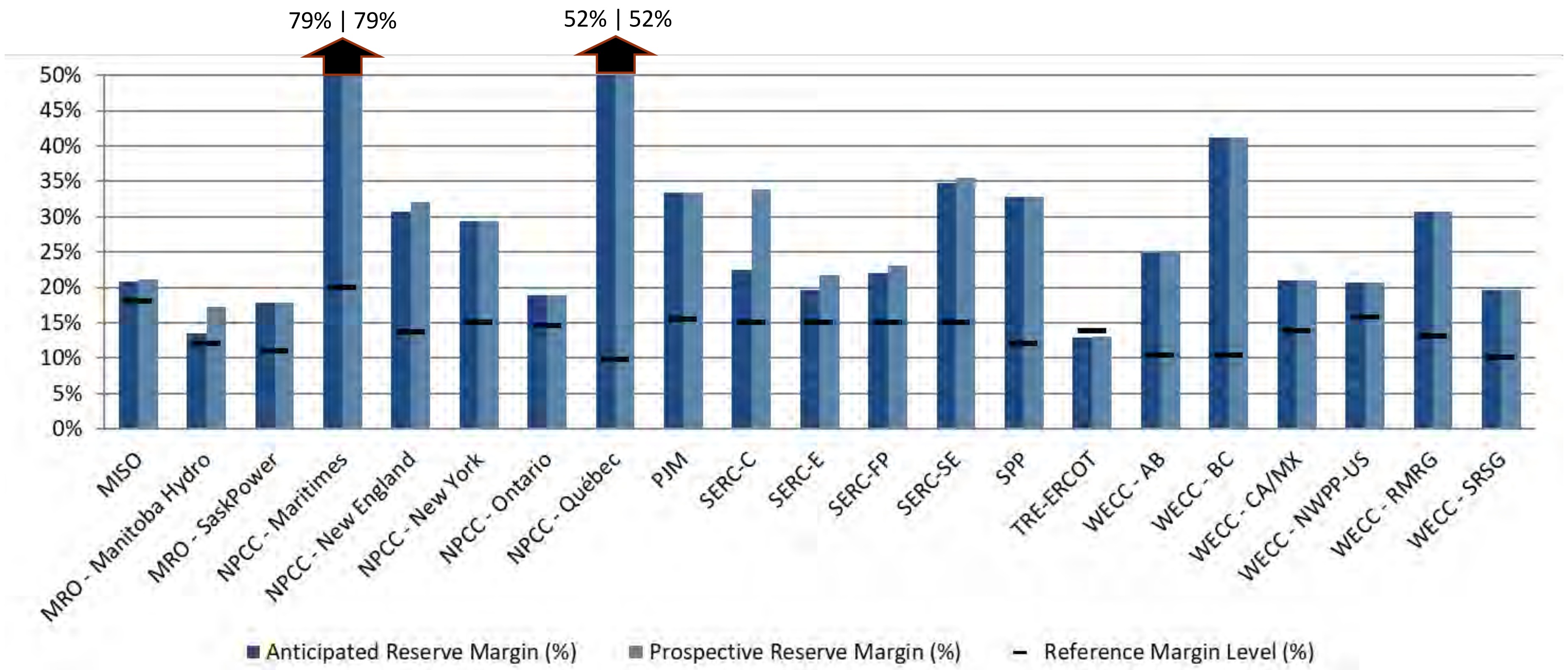


Figure 1: Summer 2020 Anticipated / Prospective Reserve Margins Compared to Reference Margin Level

[4] 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

Understanding the changes from year-to-year is an essential step in assessing an area on a seasonal basis. Figure 2 provides the relative change from the Summer 2019 to the Summer 2020 period. The Regional Assessment Dashboards provide details of the demand and resource components that make up the anticipated reserve margins for each assessment area. In the following areas, anticipated reserve margin changed by more than five percentage points: none of the changes result in a resource adequacy concern for the upcoming summer.

- **NPCC Maritimes:** The retirements of one coal-fired generator and two biomass generators contributed to lower anticipated reserve margins.
- **NPCC Ontario:** Anticipated Reserve Margins decrease due to nuclear unit refurbishments and reductions in the contribution of demand response and hydro.
- **WECC BC and WECC SRSG:** Reserve margin changes are attributed to revised variable generation capacity factors and changes in peak-hour demand.
- **WECC NWPP-US:** Forecasted summer peak demand increased by 6,300 MW (13.5%) while resource levels were relatively stable, resulting in lower reserve margins.

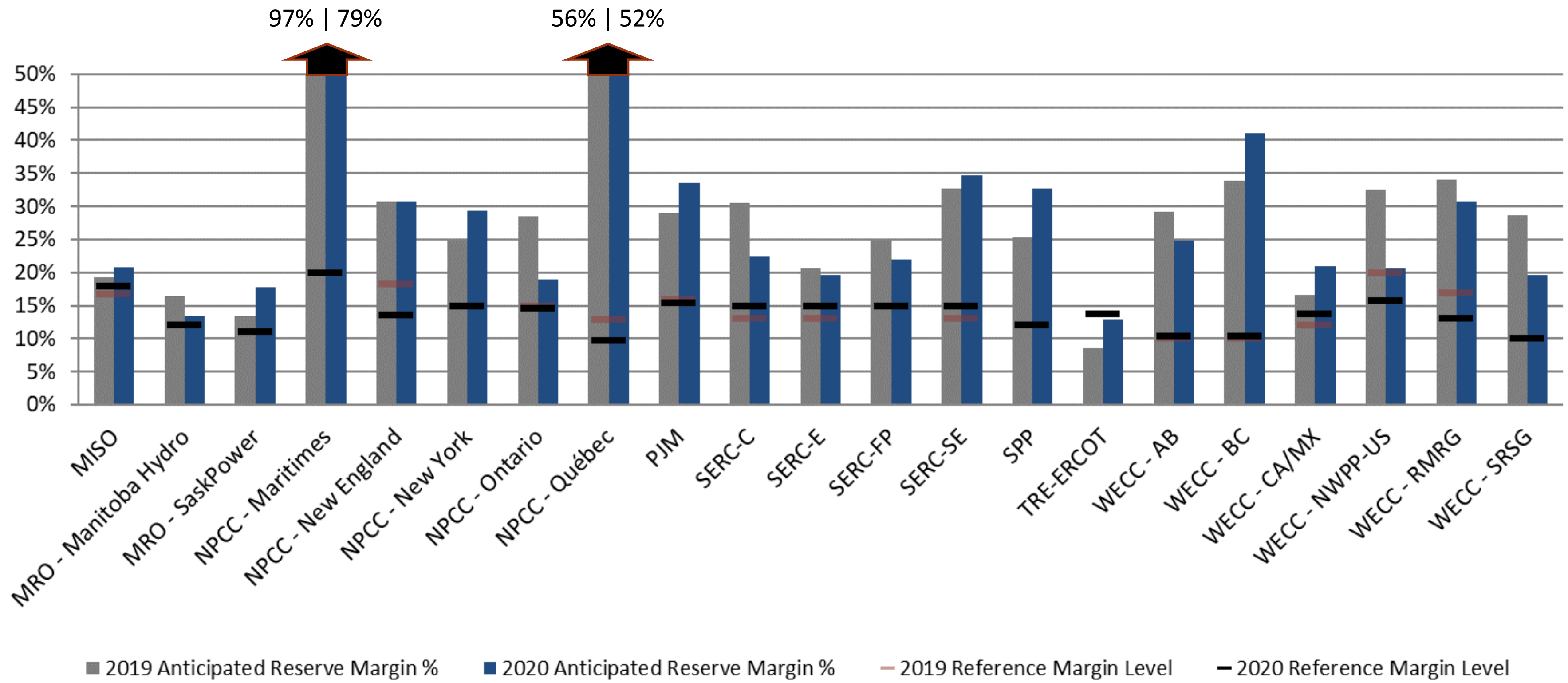


Figure 2: Summer 2019 to Summer 2020 Anticipated Reserve Margins Year-to-Year Change

Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in Figure 3.[5] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

Most assessment area demand projections in this assessment have not been decreased to account for COVID-19 mitigation measures. Although government and societal responses to halt the spread of the coronavirus (i.e., shelter-in-place orders, minimal travel, and restrictions on public gatherings) have resulted in near-term decreased electricity demand, impact projections for summer are difficult to forecast. ERCOT is an exception, where planners reduced the pre-seasonal peak demand forecast by 1,496 MW but still anticipate potentially record-setting peak demand. The demand projections used in Figure 3 and elsewhere throughout this report are likely higher than would be expected with pandemic mitigation completely factored in.

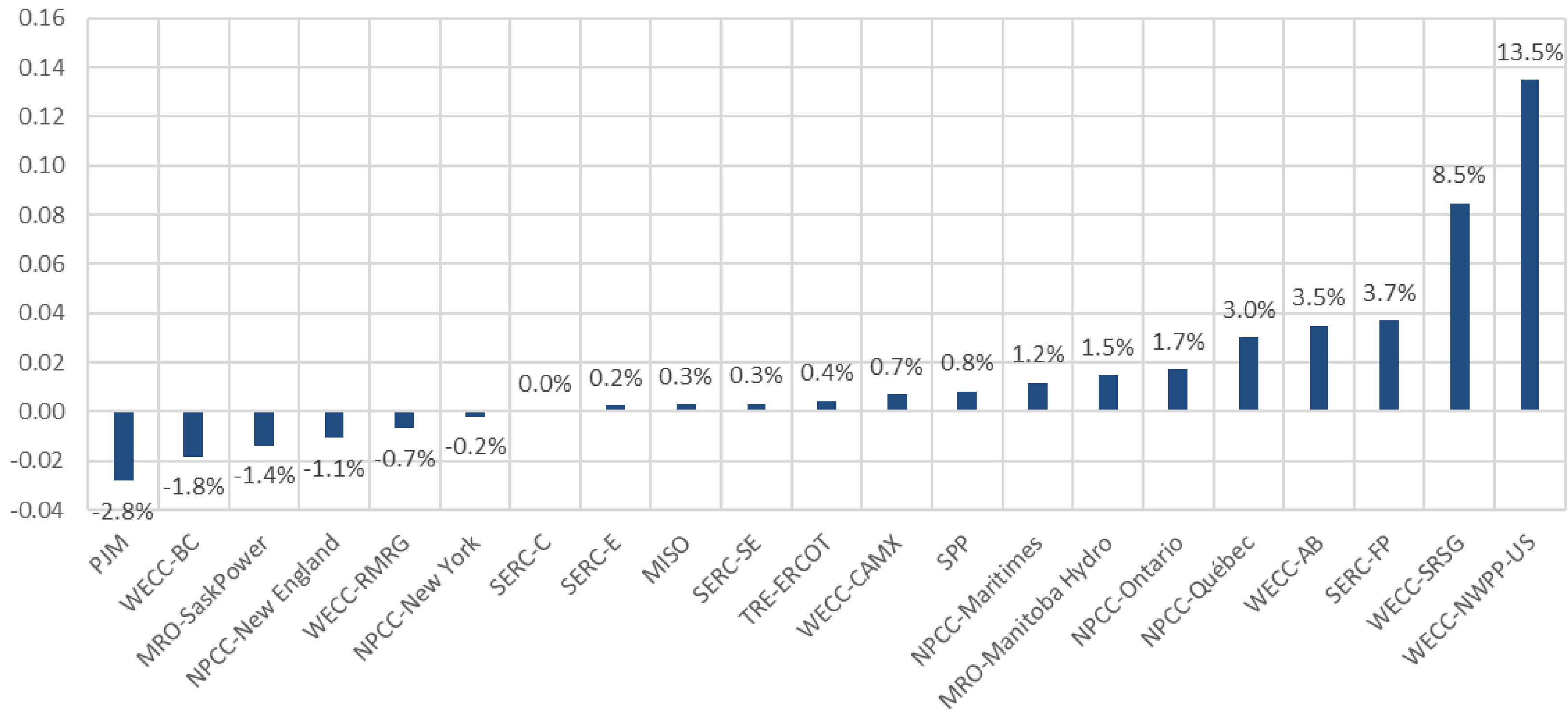


Figure 3: Change in Net Internal Demand: 2020 Summer Forecast Compared to 2019 Summer Forecast

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

Pandemic Preparedness and Operational Assessment—Summer 2020

The global health crisis has elevated the electric reliability risk profile due to potential workforce disruptions, supply chain interruptions, and increased cyber security threats. In April, NERC released its *Pandemic Preparedness and Operational Assessment – Spring 2020* (special report) to advise electricity stakeholders of the reliability considerations and assess the operational preparedness of the BPS owners and operators during pandemic conditions in April and May 2020. In its special report, NERC did not identify any specific threat or degradation to the reliable operation of the BPS for the spring time frame. The ERO continues to assess risks and conditions and is pursuing all available avenues to continue coordination with federal, state, and provincial regulators as well as work with industry to identify reliability implications and lessons learned.

Increased Reliability Risk Profile by Operating Period

Spring 2020	Summer 2020	Long-Term
• No specific reliability issue identified • Potential workforce disruptions • Supply chain interruption • Increased cyber security threat and monitoring • Different system conditions including lower demands and higher voltages. • System operators under sequester • Noncritical staff are remote	• Continued potential for workforce disruptions; support service disruption • Potential equipment and fuel supply chain disruptions • Deferred generation maintenance and other factors impacting unit availability • Generation in-service dates	• Potential changes to generation and transmission in-service dates • Increased remote operation of non-critical staff • Changes to pandemic preparedness and operating plans based on lessons learned Note: a more granular assessment will be Included in NERC's 2020 Long-Term Reliability Assessment

Since the start of the widening coronavirus infection in North America in February 2020, registered entities have taken steps from pandemic plans and industry advisories to maintain the reliability and security of the BPS. In March 2020, the Electricity Subsector Coordinating Council (ESCC) issued the first version of the *ESCC Resource Guide*[6] as a resource for electric power industry leaders to guide informed localized decisions in response to the COVID-19 global health emergency; it is updated on a regular basis as new approaches, planning considerations, and issues develop. The guide highlights data points, stakeholders, and options to consider in making decisions about operational status while protecting the health and safety of employees, customers, and communities. Sharing experiences and expertise helps users of the guide to make independent, localized decisions aimed at reducing negative impacts to the continent's power supply during the COVID-19 global pandemic. In addition to immediate measures designed to protect critical operations, personnel, and functions, entities are working to minimize risk to resource and BPS equipment availability, assure fuel supplies, and prepare operating personnel for peak season.

Maintenance Preparations for Summer Impacted

Since electricity demand is lower in a typical spring season than peak summer and winter periods, Transmission and Generator Owners normally have the opportunity to schedule maintenance and address training needs. Pandemic response and mitigation plans at national, state, provincial, and local levels can impact maintenance efforts by disrupting the flow of personnel and supply chains. Some delays to transmission projects due to disrupted travel of specialized contractors has been reported. To avoid the risk of failing to complete maintenance on time, some owners and operators have deferred or cancelled preseason maintenance in response to pandemic-related issues as can be seen by the MISO area example in **Figure 4**.

[6] https://www.electricitysubsector.org/

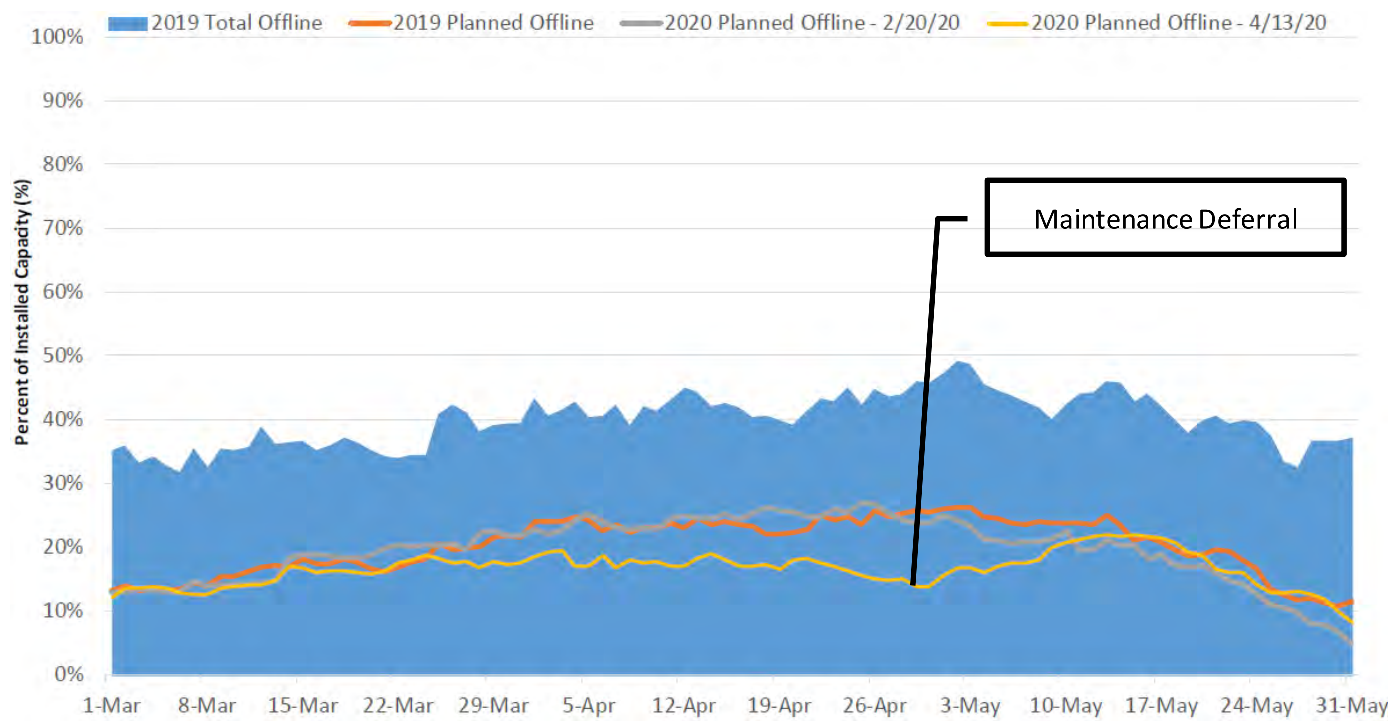


Figure 4: Generation Capacity Planned to be Off-line in MISO through May 31, 2020 (Scheduled February 20 and April 13, 2020).

In ERCOT, planners observed a higher-than-normal volume of generator maintenance outages in late March/early April possibly due to Generator Owners accelerating maintenance schedules to get ahead of potential supply chain or personnel delays. Planners and operators continue to manage schedules of equipment outages into the summer season to ensure sufficient resource availability and transmission system readiness. Maintenance that would have been performed prior to summer but is deferred can increase the risk of forced outages.

Operators in areas where a large portion of generators have deferred maintenance could experience higher-than-expected forced outages that could lead to generation supply deficiencies during periods of peak demand. NERC is implementing codes for its Generator Availability Data System (GADS) that will support collection of data on outages with pandemic causes for use in analyzing reliability impacts in later months.[7]

Electricity supply risk can be compounded by risks to the generator and to their supply of fuel. Natural-gas-fired generators can be at risk to fuel supply infrastructure disruption from mechanical or other issues; planners and operators in areas with impacted preseason maintenance are implementing measures to mitigate such risks. For example, in ISO-NE, the Electric/Gas Operations Committee has been conducting weekly meetings to determine and assess pandemic impacts to pipelines. The ISO has also increased surveying of generator owners and operators to assess outage risks.

[7] Information about GADS: https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx

Demand Impacts Vary and Cause Forecast Uncertainty

The pandemic is negatively impacting electricity demand in many parts of North America just as it has elsewhere around the world. Prior to summer, when government stay-at-home orders and societal response were at their highest, some areas reported as much as 15% drop off in peak demand. However, these observed demand impacts varied across North America and in some areas were negligible. Throughout the pandemic, many independent system operators and regional transmission operators have periodically reported on demand impacts.[8] In most areas, weather continues to be the predominant factor in electricity demand. Diminished peak demand resulting from pandemic does not pose any meaningful risk to reliability for the summer season.

Many areas are experiencing variations in hourly load shapes as a result of changing societal behaviors and mechanisms implemented to halt the spread of the coronavirus. In general, these areas are seeing below-normal ramp in demand in morning hours and lower evening demand as can be seen in **Figure 5**. Changes to pre-pandemic patterns can affect accuracy of day-ahead demand forecasts that are relied upon to ensure resources are available for each hour of the day. In recent years, demand and resource forecasting has become more complex—and more critical—as the generation resource mix has changed to include higher levels of variable generation, and load shape has changed with increasing solar photovoltaic (PV) resources. When operating entities began observing discrepancies between predicted and actual demand as a result of pandemic behavior, many instituted measures designed to improve the accuracy of forecasts made available to system operators. In MISO and other ISOs, support teams have increased the frequency of short-term demand forecast simulations.

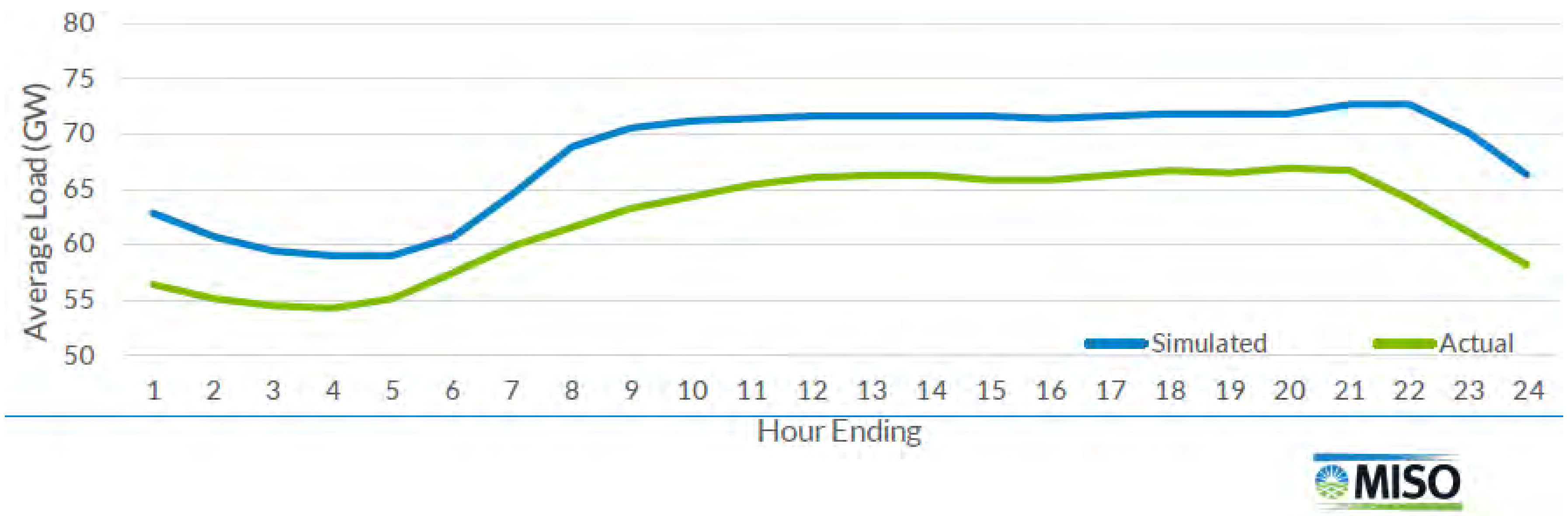


Figure 5: Average Simulated and Actual Load in MISO Area for April 4–10, 2020

[8] For example, see reports from ERCOT and CAISO: http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf http://www.ercot.com/content/wcm/lists/200201/ERCOT_COVID-19_Analysis_FINAL.pdf

Potential Demand and Resource Challenges for System Operators

Where pandemic restrictions persist through the summer, system operators could encounter difficult system characteristics, such as increased impact of DERs on load profiles, distribution reverse power flows, higher than usual operating voltages, and minimum demands at all-time lows. Operating challenges such as these need to be addressed in real-time and often by using complex tools for studying dynamic system conditions.

The effect of distributed energy resources (DERs) on system performance can become more pronounced as synchronous generation can be replaced on the system during periods of lower minimum demand; operators could face challenges in maintaining sufficient amounts of frequency-responsive reserves necessary to regulate or arrest changes in frequency. Typically, DER effects on the system are more pronounced in the spring when milder temperatures reduce air conditioning load and increase efficiency in solar PV modules. With potentially lower demand on the system as a result of the pandemic, these conditions could extend into early summer. In areas with higher DER penetration (e.g., California and North Carolina), minimum loads and reverse power flows from the distribution system can cause some challenges for system operators.

Operators in some areas may also have to contend with how a reduction in industrial and commercial loads could affect operating strategies and emergency plans. The potential lack of industrial and commercial load could alter underfrequency or undervoltage load shedding plans that rely on tripping these loads as well as demand response programs that may be relied on to support emergency operations.

Operating Reliability Considerations

- Increased uncertainty in demand projections and daily use
- Potential for increased forced outages due to deferred maintenance, staff unavailability, or limited supplies and/or fuel
- Higher than usual operating voltages
- Light load conditions
- Reverse power flow and increased penetration levels of DERs
- Potential for reduced effectiveness in underfrequency/voltage load shedding schemes as industrial and commercial load may not be online

Utility Crews and Operators Must Stay Postured for Reliability, Security, and Resilience

As the coronavirus crisis unfolds in the lead up to summer, the industry is preparing to operate with a significantly smaller workforce, an encumbered supply chain, and limited support services for an extended and unknown period of time. Vigilance to cyber security threats intensifies as risks are elevated due to a greater reliance on remote working arrangements. The business continuity and pandemic plans developed by the different operating entities are designed to protect the people working for them and to ensure critical electricity operations and infrastructure are supported properly throughout an emergency.

Protecting critical electric industry workforce during the COVID-19 pandemic remains a priority for reliability and resilience. System and Generator Operators have implemented operating postures and personnel restrictions prescribed by their pandemic plans in order to protect essential personnel and support reliable operations. Many of these measures will need to be maintained for the foreseeable future. There is a continuing risk that control centers or plants could be temporarily shut down if a significant number of operators or plant employees test positive for COVID-19 despite preparedness efforts, including employee sequestration. As of April, many entities had begun developing return to work plans; however, the majority of entities indicated that they expected to maintain protective protocols for operating personnel through summer and beyond. When relaxations can be implemented, operators will likely need to stay postured to return to heightened protections if warranted by public health conditions.

An important component of BPS resilience and recovery from hurricanes and major storms is the effective mutual assistance rendered by organizations from outside the storm-affected areas. The comprehensive plans in place to rapidly deploy support teams and equipment take on even greater complexity for the 2020 North American hurricane season (May–November) due to the need to safeguard personnel from coronavirus infection. In April, the ESCC updated its *Resource Guide* to provide lessons learned from the experience of the utilities, electric cooperatives, and investor-owned electric companies affected by a series of storms in late March and early April of this year. Lessons learned include considerations for maintaining social distancing at all times, planning for personnel protection equipment needs, and increased need for local logistical and coordination personnel to support a decentralized response.[9]

[9] See *ESCC Resource Guide*, Version 7, April 27, 2020, p. 47–48.

Cyber Security Risk and Information Sharing

Electricity and other critical infrastructure sectors face elevated cyber security risks arising from the COVID-19 pandemic in addition to ongoing risks. Opportunistic actors are attempting to find and exploit new vulnerabilities that arise as entities shift work processes and locations to maintain business continuity. The Electricity Infrastructure Sharing and Analysis Center (E-ISAC) continues to exchange information with its members and has posted communications and guidance from the ESCC and from government partners, and other advisories on its Portal; members are encouraged to check in regularly to receive updates. The E-ISAC also continues to provide information regarding emerging cyber threats; these include attacks on conferencing and remote access infrastructure, disinformation, and spear phishing campaigns attempting to harvest credentials and other information. Members are encouraged to actively share information regarding threats and other malicious activities with the E-ISAC to enable broader communication with other sector participants and government partners.

Operational Risks Highlighted for Summer 2020

Seasonal Operational Risk Assessments of 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 potential variation in resource and load as well as the potential effects that operating actions can have to mitigate shortfalls in operating reserves when insufficiencies occur. **Figure 6** shows an example seasonal risk assessment for the Southwest Power Pool (SPP) area that NERC developed using SRA data. A description of resource and demand variables is found in **Table 1**.

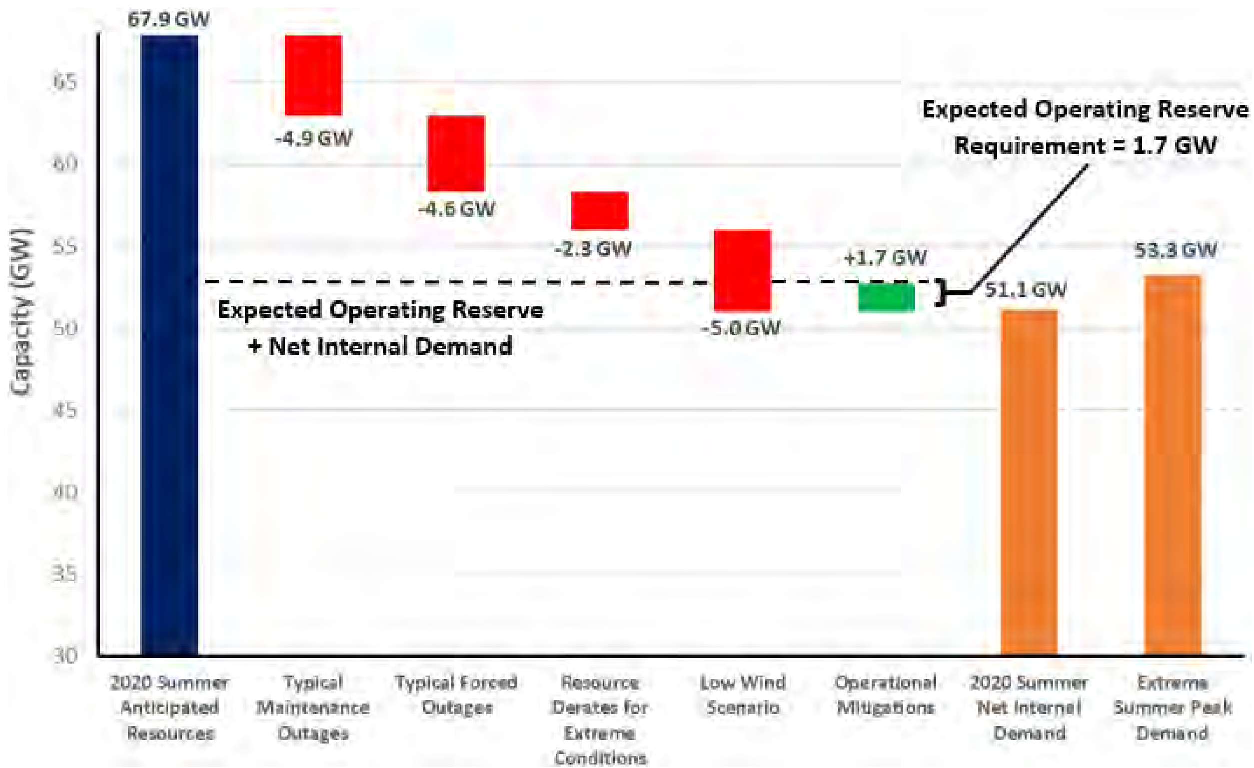


Figure 6: SPP Assessment Area Seasonal Risk Assessment

About the Seasonal Risk Assessment

The operational risk analysis shown in Figure 6 provides a deterministic scenario for understanding how various factors affecting 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 SRA 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 summer 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 SPP seasonal risk scenario in Figure 6 can be found for each assessment area in the Regional Assessment Dashboards section of this report.

The seasonal risk assessment for the SPP assessment area shows that resources are available to meet peak summer demand, including normally hot and humid summer conditions. However, extreme heat and summer conditions, such as those associated with record-setting temperatures, could increase demand and reduce generator performance enough to cause operating emergencies. A low-output wind generation event, though rare, could lead to operating actions, including conservative operations plans and EEA declarations, to manage resources and demand. Despite anticipated resources in excess of Reference Margin Levels as shown in Figure 1, operators in SPP and other areas of North America can face resource constraints during extreme summer weather.

During the past two summers, system operators in SPP needed to take operating actions, including issuing one EEA in August 2019, to address resource shortfalls. In some instances, operators were responding to higher than expected planned and forced outages coupled with real time forecasting errors for load and wind. SPP has established operational mitigation teams and developed enhanced processes and procedures to support operators in maintaining real time reliability.

Table 1: Resource and Demand Variables in the SPP Seasonal Risk Assessment	
Resource Scenarios	
Typical Maintenance Outages	Typical maintenance outages refer to an estimate of generation resources that will be out for maintenance during peak demand conditions. SPP calculated a value of 4,926 MW based on historical averages.
Typical Forced Outages	Typical forced outages refer to an estimate of generation resources that will experience forced outage during peak load conditions. SPP calculated a value of 4,638 MW based on historical averages.
Resource Derates for Extreme Conditions (Low-likelihood)	An estimated capacity derate due to extreme conditions is calculated and used for a low-likelihood resource scenario. The derate accounts for reduced capacity contributions due to generator performance in extreme conditions. SPP calculated a capacity derate of 2,276 MW for thermal generation due to extreme conditions.
Low-Wind Scenario (Low-likelihood)	The low-wind scenario is used to analyze the impact of low-likelihood weather conditions that severely reduce output from wind generation resources. A capacity adjustment of 5,017 MW is based on a low wind generator output historical event observed by system operators during summer peak conditions.
Operational Mitigations	SPP estimates that certain operational mitigations can contribute 1,700 MW of additional resources to support maintaining operating reserve requirements.
Demand Scenarios	
2020 Summer Net Internal Demand	Net internal demand 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. It is based on historical average weather (i.e., forecasts for a 50/50 distribution).
Extreme Summer Peak Load	A seasonal load adjustment (2,313 MW) is added to 2020 Net Internal Demand to account for extreme weather conditions. The adjustment is 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 of this report. Potential extreme generation resource outages and peak loads that can accompany extreme hot or humid weather may result in reliability risks in MISO, SPP, and ERCOT as well as the Canadian provinces of Manitoba, Saskatchewan, and the Maritimes. Parts of the system within the WECC area, including California ISO, 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.

Wildfire Risk Potential and BPS Impacts

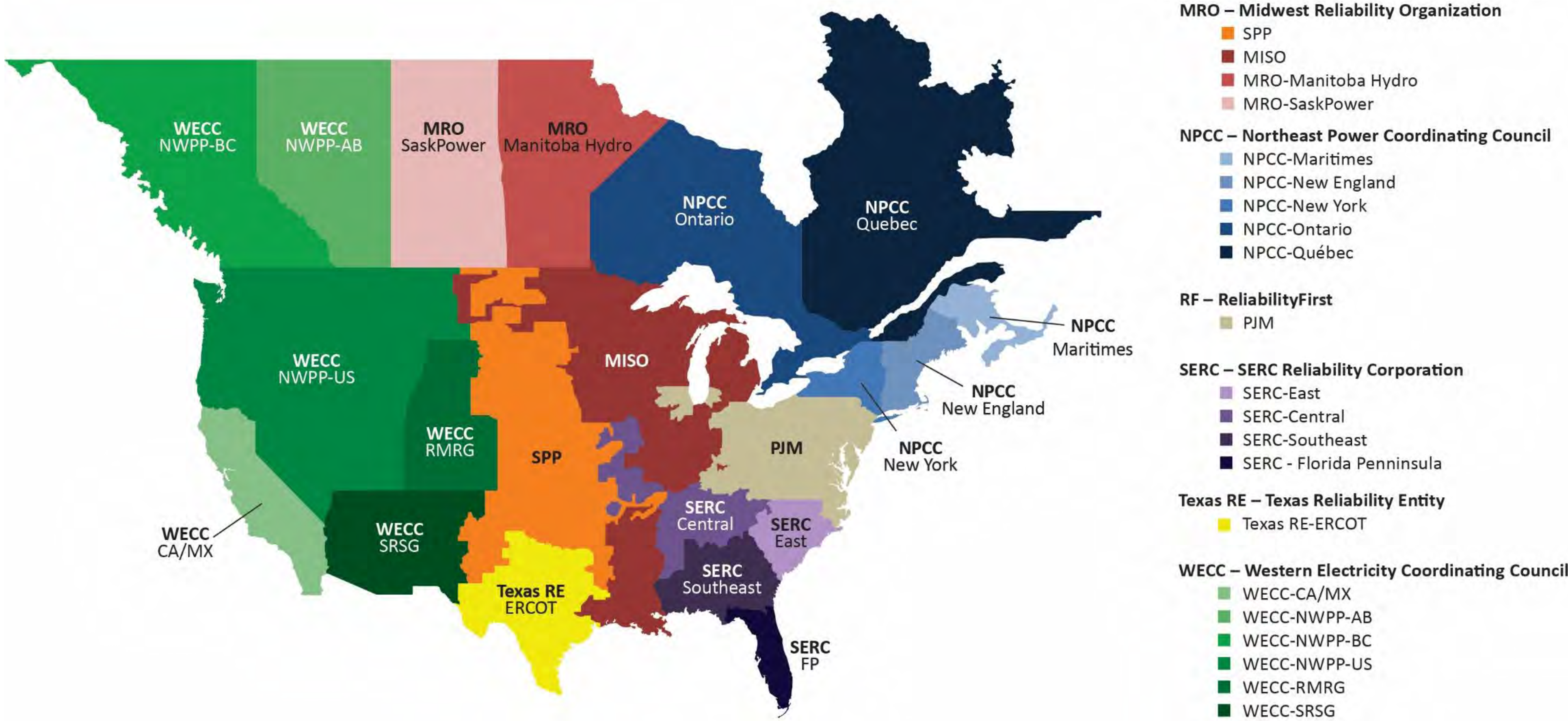
Government agencies predict normal to below-normal wildfire risk at the start of summer for the West Coast of the United States and the southwestern states. However, the latest three-month *Seasonal Fire Assessment and Outlook* published by the National Interagency Fire Center, Natural Resources Canada, and National Meteorological Service in Mexico warns that the trend toward warmer, drier weather could lead to above normal wildland fire potential in Northern California, Oregon, and Washington beginning in June.[10] Across most of western Canada, weather patterns and forecasts also suggest increased potential for wildland fires.

Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. Wildfire prevention planning in California and other areas include power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines, including transmission-level lines, may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures.

[10] See *North American Seasonal Fire Assessment and Outlook*, May 2020: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

Regional Assessment Dashboards

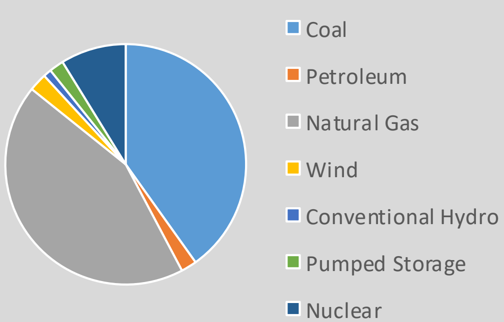
The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis.



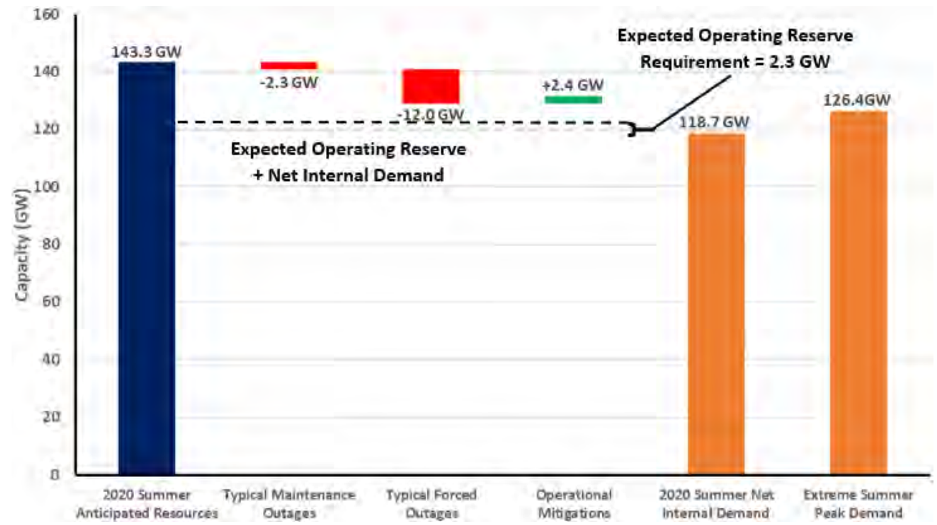
MISO

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 that serves approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.



Seasonal Risk Scenario



MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2019 SRA	2020 SRA	2019 vs. 2020 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	124,744	124,866	0.1%
Demand Response: Available	6,385	6,172	-3.3%
Net Internal Demand	118,359	118,694	0.3%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	139,220	140,636	1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,955	2,795	42.9%
Anticipated Resources	141,175	143,430	1.6%
Existing-Other Capacity	591	290	-50.9%
Prospective Resources	141,766	143,720	1.4%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	19.3%	20.8%	1.5
Prospective Reserve Margin	19.8%	21.1%	1.3
Reference Margin Level	16.8%	18.0%	1.2

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels, with adjustments for normal and extreme conditions. MISO determined the adjustments to summer capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Observation:

Resources meet operating reserve requirements under normal demand and outage scenarios. Extreme summer peak demand or outages could result in a need to employ operating procedures to mitigate resource shortfall.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Average from highest peak hour over the past five summers

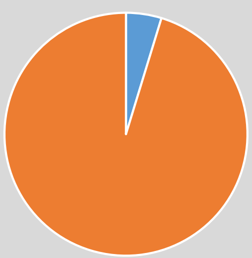
Highlights

- Summer scenarios with high resource outages and high demand may require use of load modifying resources during peak periods as load modifying resources become an increasingly important segment of MISO's resource portfolio.
- Though MISO remains resource adequate for the 2020 summer, some areas may be resource and import constrained presenting local operating challenges.
- Near-term impacts of COVID-19 have resulted in generally lower loads and shifted morning and evening peaks to later hours. It is unclear how observed trends will change through the summer months.

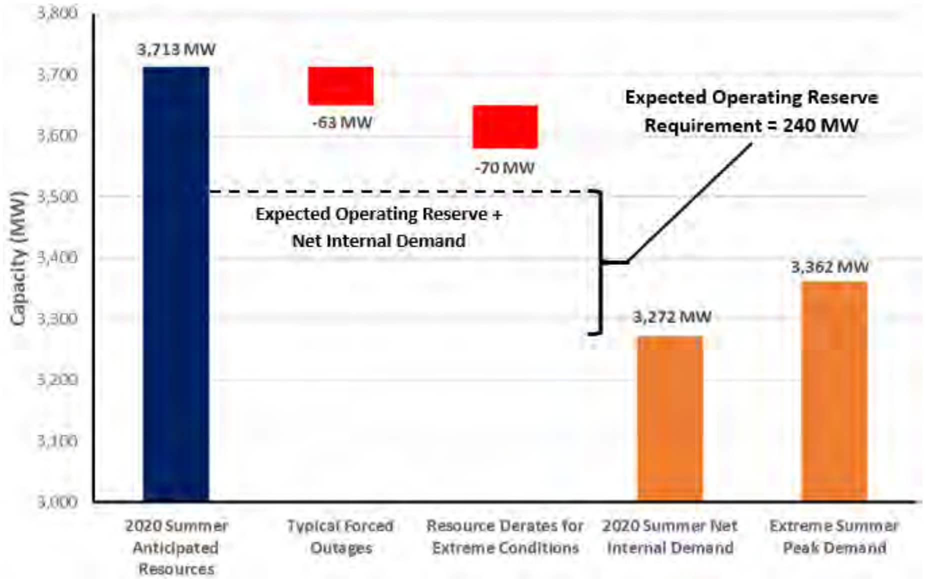
MRO-Manitoba Hydro

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 people 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.



Seasonal Risk Scenario



MRO-Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,224	3,272	1.5%
Demand Response: Available	0	0	-
Net Internal Demand	3,224	3,272	1.5%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,161	5,239	1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,408	-1,526	8.4%
Anticipated Resources	3,753	3,713	-1.1%
Existing-Other Capacity	215	125	-41.6%
Prospective Resources	3,968	3,838	-3.3%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	16.4%	13.5%	-2.9
Prospective Reserve Margin	23.1%	17.3%	-5.8
Reference Margin Level	12.0%	12.0%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. MRO-Manitoba determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under normal demand and outage scenarios.

Scenario Assumptions

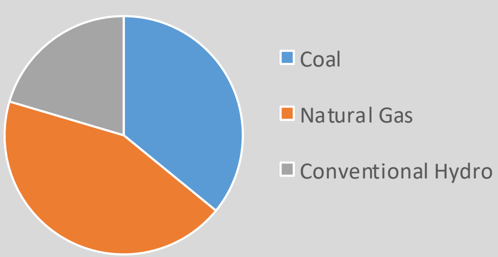
- **Extreme Peak Demand:** All-time highest peak load
- **Outages:** Based on historical operating experience
- **Extreme Derates:** Thermal units derated for extreme temperature where appropriate.

Highlights

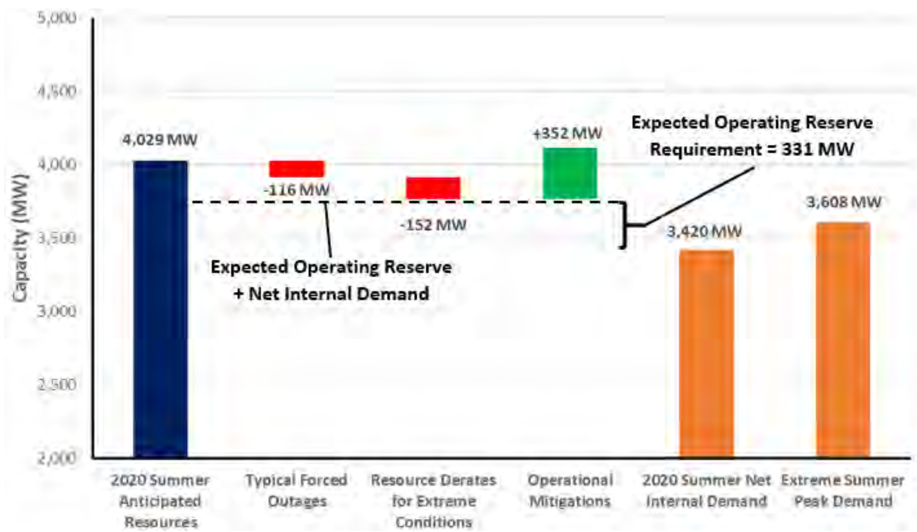
- Manitoba Hydro has implemented measures to minimize coronavirus impact risk to operations. While the COVID-19 Pandemic is expected to be present over the summer assessment period, an impact on BPS reliability is not anticipated.
- Reservoir storage levels are above average and more than adequate to withstand the design-basis drought conditions.

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, under provincial legislation, and is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.



Seasonal Risk Scenario



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. MRO-SaskPower determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the **Data Concepts and Assumptions** for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under normal scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption.)

Scenario Assumptions

- **Extreme Peak Load:** Peak demand with lighting and all large consumer loads
- **Maintenance Outages:** Estimated based on average maintenance outages for June, July, August, and September for 2019
- **Forced Outages:** Estimated using SaskPower forced outage model
- **Extreme Derates:** Derate on natural gas units based on historic data and manufacturer data

MRO-SaskPower Resource Adequacy Data

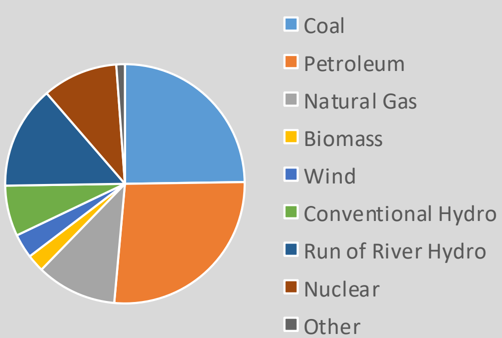
Demand, Resource, and Reserve Margin	2019 SRA	2020 SRA	2019 vs. 2020 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,553	3,480	-2.1%
Demand Response: Available	85	60	-29.4%
Net Internal Demand	3,468	3,420	-1.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	3,907	3,904	-0.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	25	125	400.0%
Anticipated Resources	3,932	4,029	2.5%
Existing-Other Capacity	0	0	-
Prospective Resources	3,932	4,029	2.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	13.4%	17.8%	4.4
Prospective Reserve Margin	13.4%	17.8%	4.4
Reference Margin Level	11.0%	11.0%	0.0

Highlights

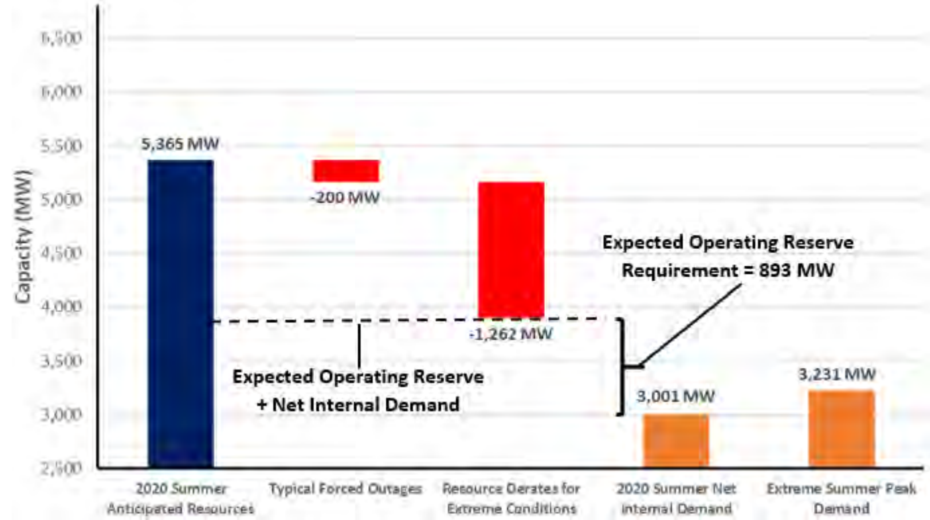
- Saskatchewan experiences high load in summer as a result of extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outage occurs during peak load times in the end of August to early October 2020 when 641 MW of SaskPower's natural gas generating station is off-line for overhaul maintenance.

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion 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 that is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.



Seasonal Risk Scenario



NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	3,255	3,370	3.5%
Demand Response: Available	289	369	27.7%
Net Internal Demand	2,966	3,001	1.2%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	5,842	5,312	-9.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	0	53	0.0%
Anticipated Resources	5,842	5,365	-8.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,842	5,365	-8.2%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	97.0%	78.8%	-18.2
Prospective Reserve Margin	97.0%	78.8%	-18.2
Reference Margin Level	20.0%	20.0%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Maritimes determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating requirements under normal peak load scenario. Extreme summer peak load and outage conditions could result in the need to employ operating mitigation to manage resource shortfall.

Scenario Assumptions

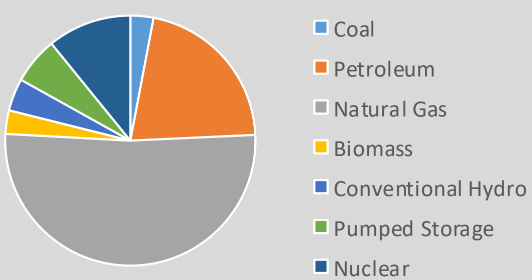
- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Based on historical operating experience
- **Extreme Derates:** An extreme, low-likelihood scenario is used whereby thermal units are derated for extreme temperature and all wind unit capacity is unavailable

Highlights

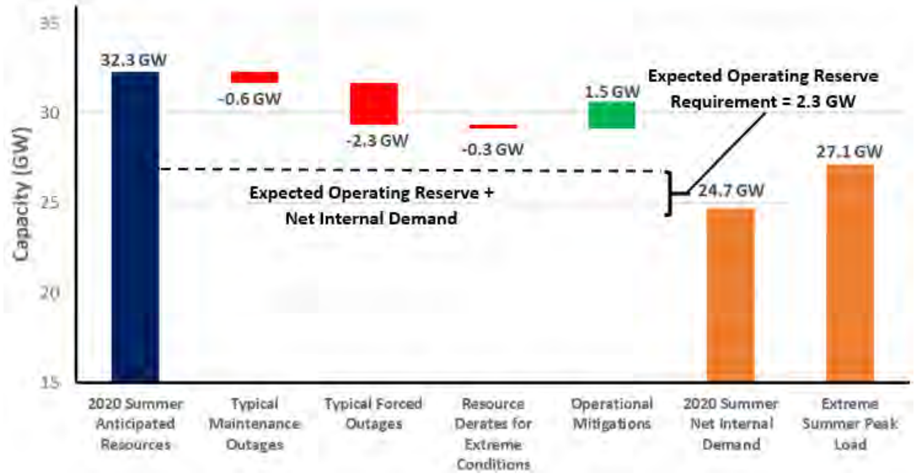
- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations procedures in place. All of the area's declared firm capacity is expected to be operational for the summer operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.
- The effects of the COVID-19 pandemic on load patterns, energy use, and peak demands will continue to be evaluated as the pandemic evolves.
- The Maritimes are evaluating contingency plans for transmission, distribution and generation planned work, planned maintenance and forced outages to proceed conservatively while mitigating short term and longer term reliability risks.

NPCC-New England

ISO New England (ISO-NE) Inc. is a regional transmission organization that serves 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, and it also administers the area's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.



Seasonal Risk Scenario



NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	25,323	25,158	-0.7%
Demand Response: Available	340	443	30.3%
Net Internal Demand	24,983	24,715	-1.1%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	30,144	30,791	2.1%
Tier 1 Planned Capacity	1,185	0	-100.0%
Net Firm Capacity Transfers	1,328	1,510	13.7%
Anticipated Resources	32,657	32,301	-1.1%
Existing-Other Capacity	704	324	-54.0%
Prospective Resources	33,361	32,625	-2.2%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	30.7%	30.7%	0.0
Prospective Reserve Margin	33.5%	32.0%	-1.5
Reference Margin Level	18.3%	18.3%	0.0

The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-New England determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 Forecast
- **Outages:** Based on weekly averages
- **Operating Mitigations:** Based on ISO-NE operating procedures

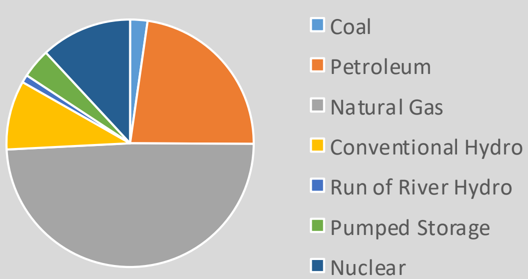
Highlights

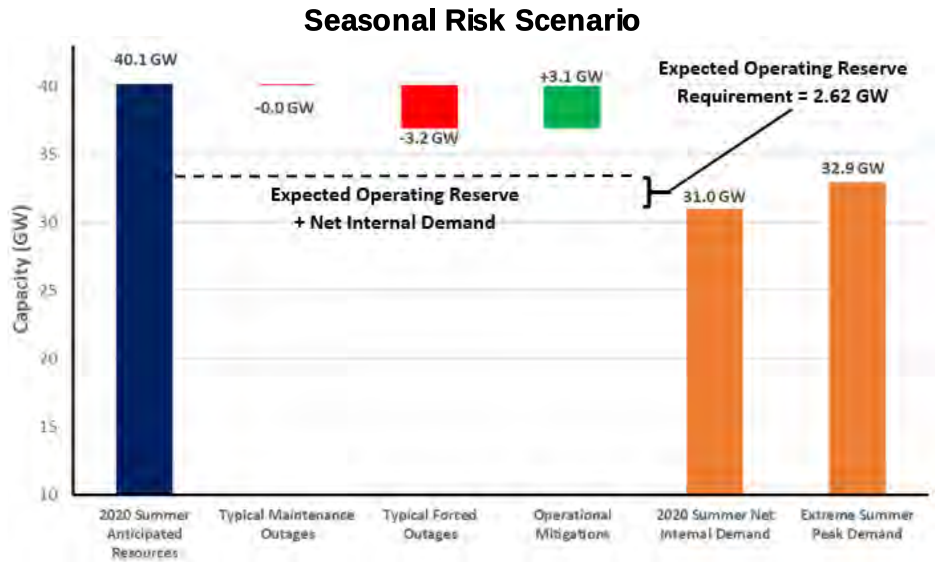
- The New England Area expects to have sufficient resources to meet the 2020 summer peak demand forecast of 25,158 MW for the week beginning July 5, 2020, with a projected net margin of 3,197MW (12.7%). The 2020 summer demand forecast is 165 MW (0.7%) less than the 2019 summer forecast of 25,323 MW and takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.
- With residents and businesses across New England changing their behavior in response to the COVID-19 pandemic, ISO New England is seeinga decline in system demand of approximately 3–5% compared to what would normally be expected under weather conditions in the area. These percentages may change over time.
- In addition to overall declines in consumer demand, these societal changes are also affecting demand patterns across the region. Though the pandemic is affecting energy use, weather conditions remain the primary drivers of system demand. ISO-NE will continuously monitor these ever-changing trends in load patterns and make the appropriate adjustments to calculate an accurate load forecast. The area's power system continues to remain reliable.

NPCC-New York

The New York Independent System Operator (NYISO) is the only Balancing Authority within the state of New York. NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. NYISO manages the New York State transmission grid that encompasses approximately 11,000 miles of transmission lines, more than 47,000 square miles, and serving the electric needs of 19.5 million people. New York experienced its all-time peak load of 33,956 MW in the summer of 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 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 18.9%.





The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-New York determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Demand:** 90/10 load forecast with demand response adjustments
- **Extreme Derates:** Near-zero MW due to summer peaking area
- **Typical Outages:** Based on scheduled maintenance and GADS forced outage data
- **Operational Mitigation:** 3.1 GW based on operational/emergency procedures in NYISO *Emergency Operations Manual*

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	32,382	32,296	-0.3%
Demand Response: Available	1,309	1,282	-2.1%
Net Internal Demand	31,073	31,014	-0.2%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	37,304	38,475	3.1%
Tier 1 Planned Capacity	27	101	274.8%
Net Firm Capacity Transfers	1,452	1,562	7.6%
Anticipated Resources	38,783	40,138	3.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	38,783	40,138	3.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	24.8%	29.4%	4.6
Prospective Reserve Margin	24.8%	29.4%	4.6
Reference Margin Level	15.0%	15.0%	0.0

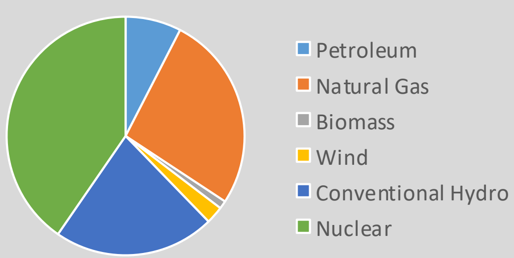
Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- 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 determined and approved annually by the New York State Reliability Council (NYSRC). NYSRC approved a 2020–2021 IRM of 18.9%. The IRM meets the NPCC and NYSRC criterion of a loss of load expectation of no greater than 0.1 days per year. Its calculation is based on a study that accounts for the forced outage rates of thermal generators, the peak load forecast, the load forecast uncertainty, the actual hourly production data for wind and solar over the most recent five-year calendar period, long term capacity imports and exports, demand response programs derated to account for historic availability, various emergency operation procedures, and assistance from neighboring control areas. Historically since 2000, the IRM has ranged between 15.0% and 18.9%.

NPCC-Ontario

The Independent Electricity System Operator (IESO) is the Balancing Authority and Reliability Coordinator for the province of Ontario. In addition to administering the area's wholesale electricity markets, the IESO plans for Ontario's future energy needs. Ontario covers more than 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.

Ontario IESO treats demand response as a resource for its own assessments while in the NERC assessment demand response is used as a load-modifier. As a result, the total internal demand, reserve margin, and Reference Margin Level values differ in IESO's reports when compared to NERC reports.



The table and chart above provide potential summer peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Ontario determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** Determined from the most severe historical weather
- **Extreme Derates:** Based on thermal unit derating curves and historical hydro performance for a low-water year
- **Operational Mitigation:** 2,000 MW imports assessed as available from neighbors

NPCC-Ontario Resource Adequacy Data

Demand, Resource, and Reserve Margin	2019 SRA	2020 SRA	2019 vs. 2020 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	22,105	22,195	0.4%
Demand Response: Available	790	518	-34.5%
Net Internal Demand	21,315	21,677	1.7%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	26,581	25,719	-3.2%
Tier 1 Planned Capacity	924	49	-94.7%
Net Firm Capacity Transfers	-102	0	-100.0%
Anticipated Resources	27,403	25,768	-6.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	27,403	25,768	-6.0%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	28.6%	18.9%	-9.7
Prospective Reserve Margin	28.6%	18.9%	-9.7
Reference Margin Level	14.9%	14.6%	-0.3

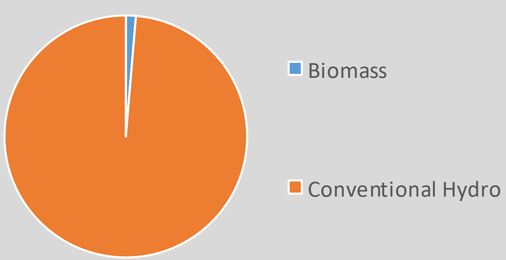
Highlights

- The IESO expects to have sufficient generation supply for Summer 2020. Likewise, Ontario's transmission system is expected to continue to reliably supply province-wide demand throughout the summer season.
- Napanee Generating Station, a 994 MW natural-gas-fired plant, was added to Ontario's generation fleet in March 2020. The Darlington Nuclear Unit G2 (936 MW) is expected to return to service following refurbishment prior to summer.
- The year-on-year reduction in anticipated/prospective reserve margin is due to a greater number of nuclear units on refurbishment outage as well as reductions in demand response and hydroelectric contributions.
- The ongoing transmission outage of the phase angle regulator on the L33 circuit at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. The issue is being jointly managed by all involved parties.

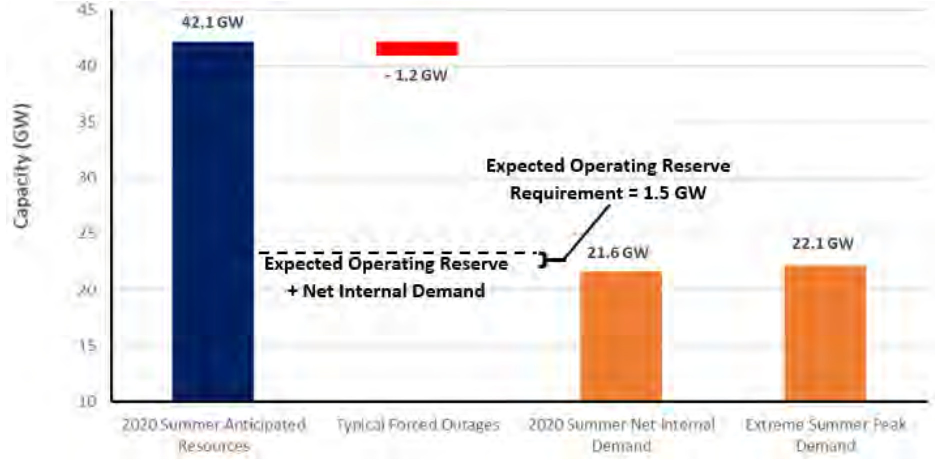
NPCC-Québec

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

Québec is one of the four 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.



Seasonal Risk Scenario



NPCC- Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	21,005	21,635	3.0%
Demand Response: Available	0	0	0.0%
Net Internal Demand	21,005	21,635	3.0%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	34,303	34,771	1.4%
Tier 1 Planned Capacity	28	14	-49.1%
Net Firm Capacity Transfers	-1,663	-1,963	18.0%
Anticipated Resources	32,667	32,822	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	32,667	32,822	0.5%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	55.5%	51.7%	-3.8
Prospective Reserve Margin	55.5%	51.7%	-3.8
Reference Margin Level	12.8%	9.8%	-3.0

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. NPCC-Québec determined the adjustments to peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Forced Outages:** Hydro resources operate in extreme conditions without increased outage rates

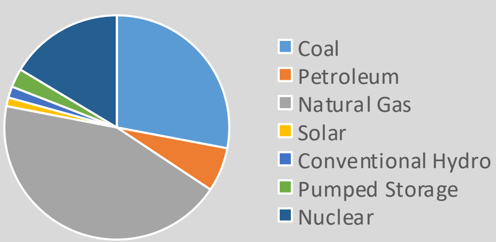
Highlights

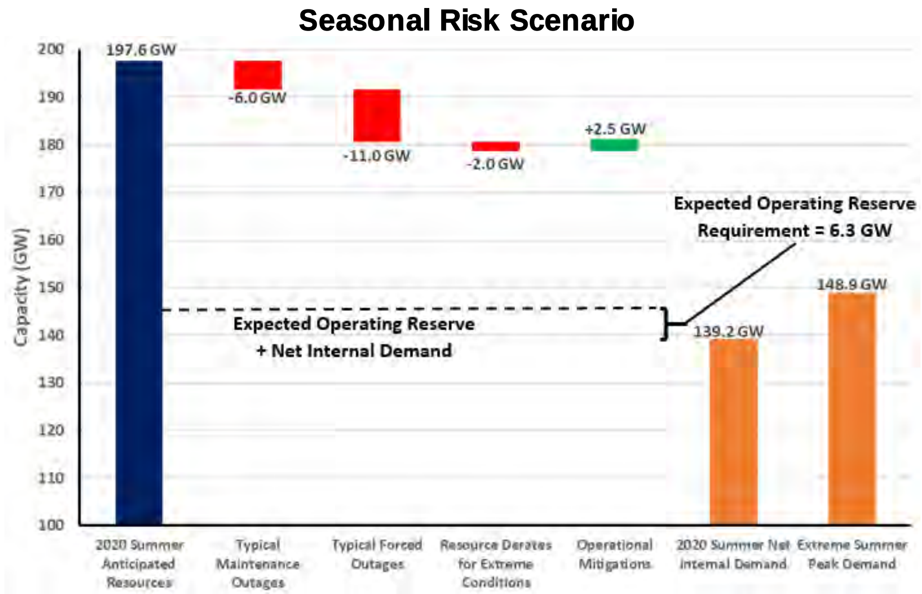
- No resource adequacy or reliability issues are anticipated for the upcoming summer operating period since the Quebec system is winter peaking.
- A strategic 735 kV line was commissioned in May 2019 in order to meet NERC Reliability Standards. The line will provide more flexibility to operators for the upcoming summer period.

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.





PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	151,358	148,092	-2.2%
Demand Response: Available	8,154	8,929	9.5%
Net Internal Demand	143,204	139,163	-2.8%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	181,013	182,523	0.8%
Tier 1 Planned Capacity	2,200	1,800	-18.2%
Net Firm Capacity Transfers	1,535	1,412	-8.0%
Anticipated Resources	184,748	185,735	7.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	184,748	185,735	7.7%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	29.0%	33.5%	4.5
Prospective Reserve Margin	29.0%	33.5%	4.5
Reference Margin Level	15.9%	15.5%	-0.4

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. PJM determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

- **Extreme Peak Load:** 90/10 forecast
- **Outages:** Approximate values based on review of previous summer peak periods

Highlights

- PJM's Anticipated Reserve Margin of 33.5% is well over the reserve margin requirement of 15.5%.
- No known operational challenges are anticipated in PJM for the upcoming summer season.
- PJM's capacity performance initiative has resulted in better generator performance than in years preceding its implementation.

SERC

On July 1, 2019, the integration of FRCC entities into SERC resulted in an additional SERC subregion (SERC FL-Peninsula) for inclusion in NERC's reliability assessments.

SERC is a summer-peaking assessment area that covers approximately 350,000 square miles and serves a population estimated at 69 million. SERC is divided into four assessment areas: SERC- E, SERC-N, SERC-SE, and SERC-FL Peninsula. The SERC assessment area includes 33 Balancing Authorities, 26 Planning Authorities, and 4 Reliability Coordinators.

SERC Resource Adequacy Data							
Demand, Resource, and Reserve Margins	**SERC-C**	**SERC-E**	**SERC-FP**	**SERC-SE**	**2019 SRA SERC Total**	**2020 SRA SERC Total**	**2019 vs. 2020 SRA**
Demand Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Total Internal Demand (50/50)	40,799	43,702	49,286	47,311	179,466	181,098	0.9%
Demand Response: Available	1,970	947	2,906	2,145	8,262	7,968	-3.6%
Net Internal Demand	38,829	42,755	46,380	45,166	171,204	173,130	1.1%
Resource Projections	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Megawatts**	**Net Change (%)**
Existing-Certain Capacity	48,368	50,825	55,093	61,495	214,712	215,780	0.5%
Tier 1 Planned Capacity	0	88	333	316	2,679	736	-72.5%
Net Firm Capacity Transfers	-807	266	1,146	-972	306	-367	-219.8%
Anticipated Resources	47,561	51,179	56,571	60,839	217,697	216,149	-0.7%
Existing-Other Capacity	4,427	852	529	348	6,034	6,155	2.0%
Prospective Resources	51,988	52,030	57,100	61,186	223,731	222,304	-0.6%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	22.5%	19.7%	22.0%	34.7%	27.2%	24.8%	-2.4
Prospective Reserve Margin	33.9%	21.7%	23.1%	35.5%	30.7%	28.4%	-2.3
Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	0.0

Highlights

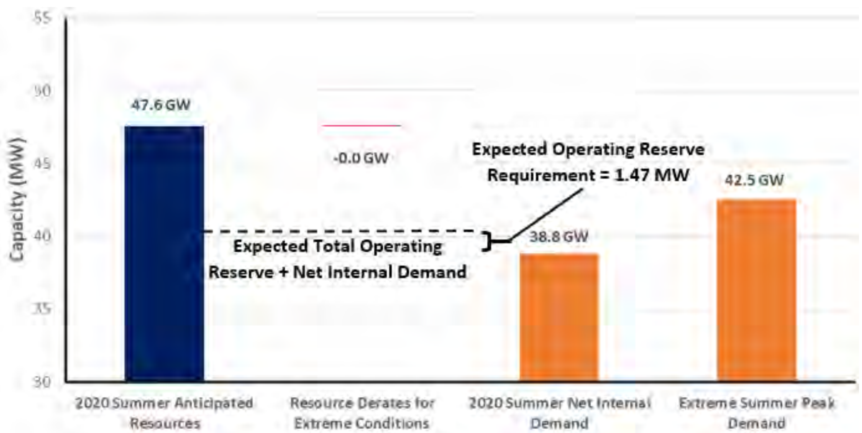
- To date in the SERC region, there are no significant reliability risks expected for the 2020 summer season.
- All subregions within SERC meet or exceed the reserve margin target of 15%.
- Entities in the SERC region continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.

Charts

The charts on the following pages provide potential seasonal peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the following pages present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. SERC determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below each chart. See the Data Concepts and Assumptions for more information about the table and charts.

SERC-C

Seasonal Risk Scenario

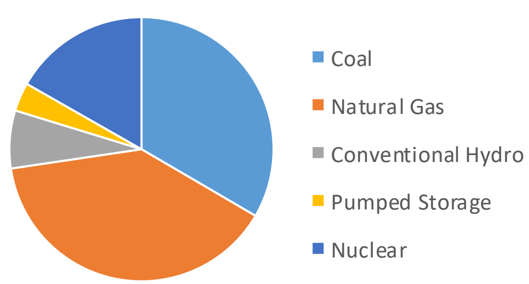


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

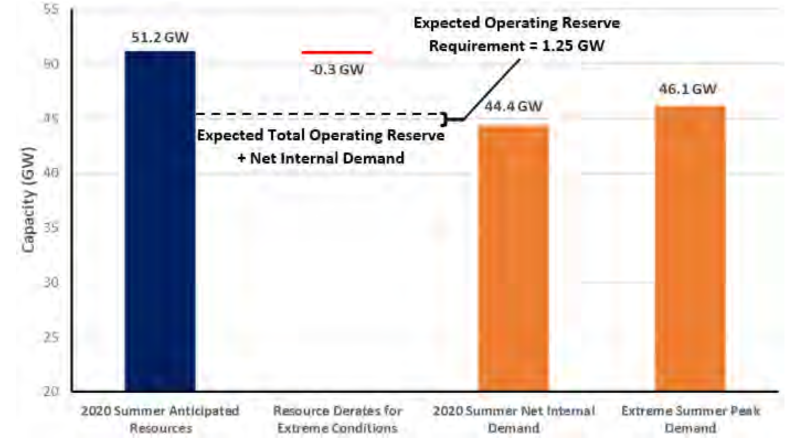
Scenario Assumptions

- **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by entities and aggregated at the subregional level



SERC-E

Seasonal Risk Scenario

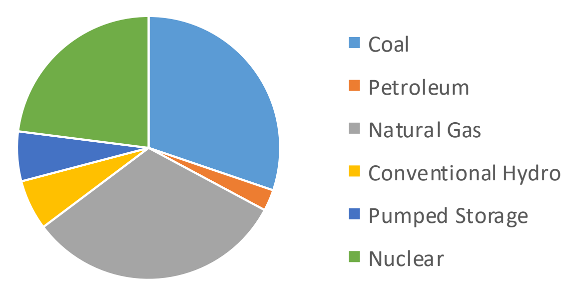


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

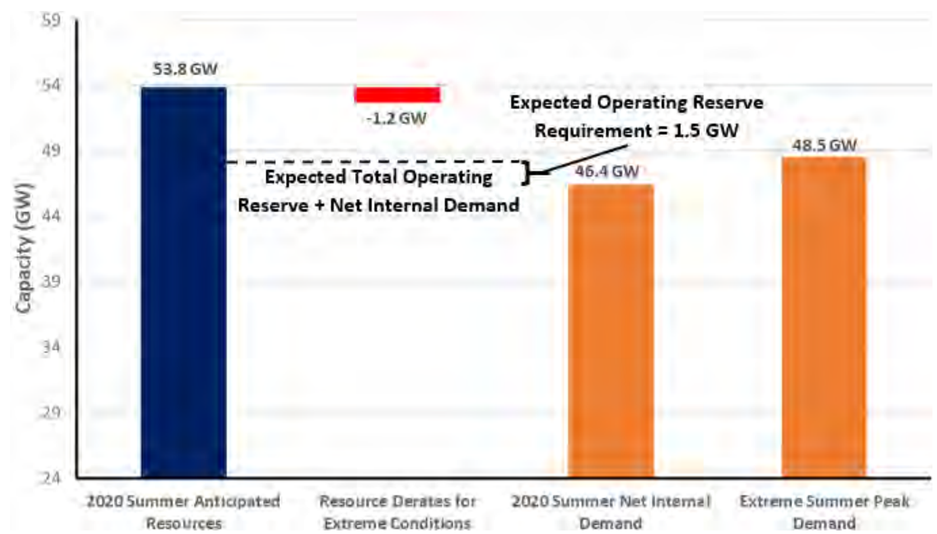
Scenario Assumptions

- **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by entities and aggregated at the subregional level



SERC-FP

Seasonal Risk Scenario

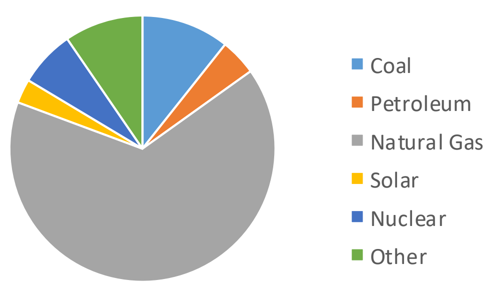


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

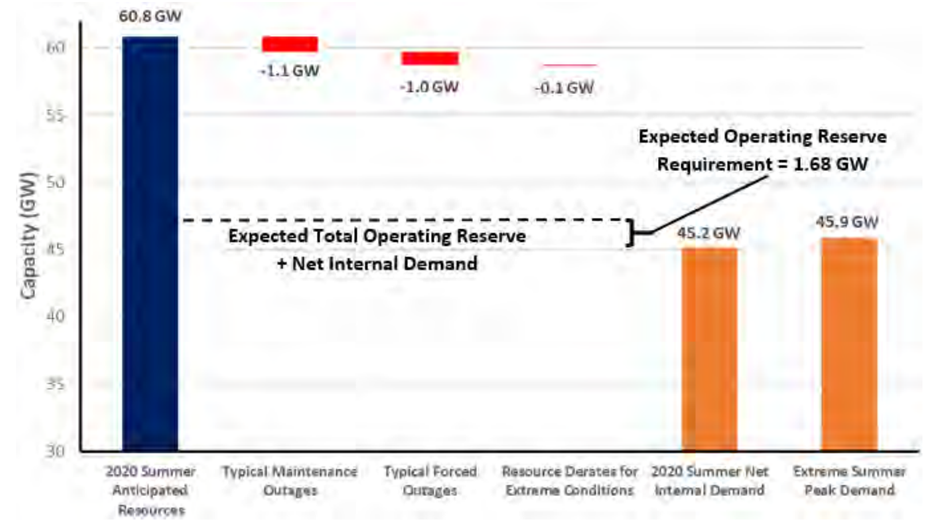
Scenario Assumptions

- **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by entities and aggregated at the subregional level



SERC-SE

Seasonal Risk Scenario

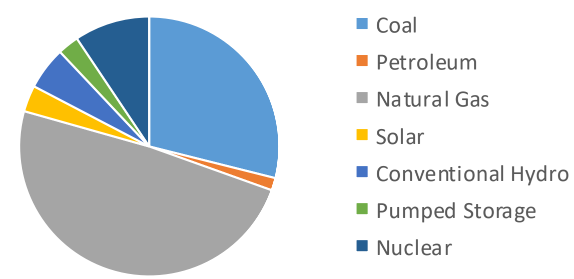


Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

Scenario Assumptions

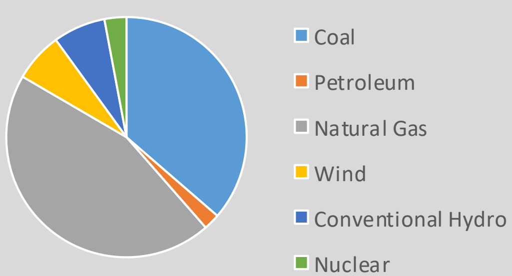
- **Extreme Peak Load:** Developed by adjusting subregional peak forecasted load using the probabilistic load multiplier developed in the SERC Probabilistic Assessment
- **Outages:** Based on historical data
- **Extreme Derates:** Determined by entities and aggregated at the subregional level

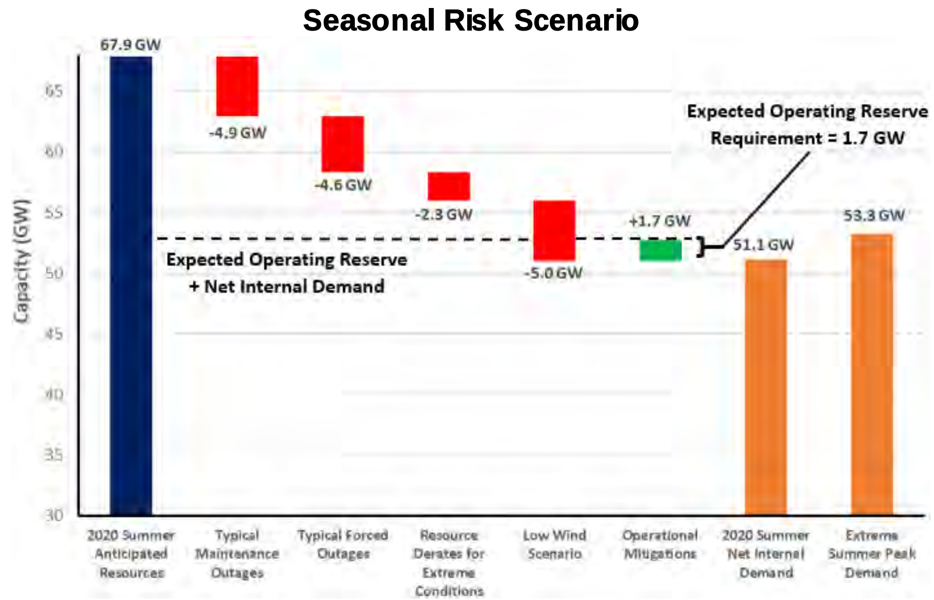


SPP

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.





SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margin	2019 SRA	2020 SRA	2019 vs. 2020 SRA
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	51,520	51,943	0.8%
Demand Response: Available	835	835	0.0%
Net Internal Demand	50,686	51,108	0.8%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	67,960	69,100	1.7%
Tier 1 Planned Capacity	64	0	-100.0%
Net Firm Capacity Transfers	-1,244	-1,244	0.0%
Anticipated Resources	66,780	67,856	1.6%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,780	67,856	1.6%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	31.8%	32.8%	1.0
Prospective Reserve Margin	31.8%	32.8%	1.0
Reference Margin Level	12.0%	12.0%	0.0

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. SPP determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below. See the Data Concepts and Assumptions for more information about this table and chart.

Risk Scenario Summary

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

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

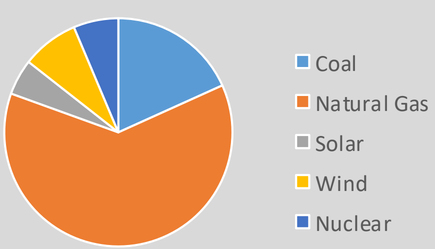
Highlights

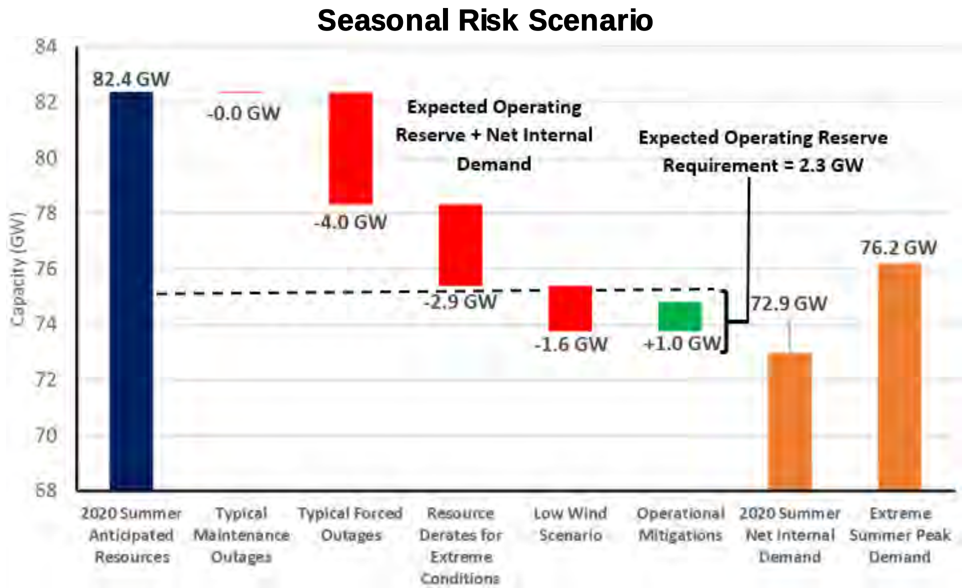
- SPP does not anticipate any emerging reliability issues impacting the area for the 2020 summer season.
- In an effort to minimize declared periods of conservative operations and EEAs that may arise from uncertainty in wind forecasts, SPP created new mitigation processes to deal with high impact areas of concern. SPP has developed operational mitigation teams as well as processes and procedures to maintain real time reliability needs; some of these are new and will be relied upon for the first time in the 2020 summer season.

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 Region that covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has over 680 generation units, and serves more than 26 million customers. Texas RE is responsible for the regional RE functions described in the *Energy Policy Act of 2005* for the ERCOT Region.





Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margin	**2019 SRA**	**2020 SRA**	**2019 vs. 2020 SRA**
Demand Projections	**MW**	**MW**	**Net Change**
Total Internal Demand (50/50)	74,853	75,200	0.5%
Demand Response: Available	2,227	2,251	1.1%
Net Internal Demand	72,626	72,949	0.4%
Resource Projections	**MW**	**MW**	**Net Change**
Existing-Certain Capacity	77,482	79,395	2.5%
Tier 1 Planned Capacity	607	2,172	257.9%
Net Firm Capacity Transfers	721	817	13.3%
Anticipated Resources	78,810	82,384	4.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	78,810	82,412	4.6%
Reserve Margins	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	8.5%	12.9%	4.4
Prospective Reserve Margin	8.5%	13.0%	4.5
Reference Margin Level	13.75%	13.75%	0.0

The table and chart above provide potential seasonal peak demand and resource condition information. The table on the right presents a standard seasonal assessment and comparison to the previous year's assessment. The chart above presents deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. ERCOT determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below.

Risk Scenario Summary

Operating mitigations and EEAs may be needed to meet extreme demand or extreme resource derated conditions.

Scenario Assumptions

- **Extreme Peak Load:** Based on 2011 historic summer peak load
- **Outages:** A derate for maintenance and forced outages based on the past three summer periods
- **Extreme Derates:** Based on 95th percentile of historical forced outages for June – September, hours ending 2:00 p.m.–8:00 p.m. for the last three summer seasons
- **Operational Mitigations:** Additional resources (e.g., switchable generation resources, additional imports, and voltage reduction) to support maintaining operating reserves, not already counted in SRA reserve margins

Highlights

- ERCOT's anticipated reserve margin, 12.9%, is higher than last summer due mainly to greater planned wind and solar capacity. Increases are attributed to completion of new projects as well as delayed projects from 2019 and improved methods for calculating wind and solar capacity contributions.
- The Planning Reserve Margin is considered tight. ERCOT expects grid operations to be similar to last summer, assuming that peak loads hit record levels as forecasted.
- ERCOT assumes the availability of 817 MW of dc tie net imports from SPP during its forecasted summer peak load hours based on recent historical experience and expected energy market conditions for the upcoming summer. Emergency conditions in both areas simultaneously would impact imports into ERCOT. ERCOT does not expect COVID-19-related delays for planned projects with expected in-service dates prior to the summer season.
- There are no known transmission reliability, fuel supply, or essential reliability service procurement issues projected for summer. Continued penetration of wind and solar resources is expected to further stress system conditions and call for additional actions to maintain system stability. Stability constraints are managed through generic transmission constraints (GTCs) in real-time operations. ERCOT assesses the impact of future planned new generation to determine the adequacy of existing GTCs and the need for developing new GTCs or system improvements.

WECC

WECC is responsible for coordinating and promoting BES 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 BES. 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 states of the United States in between. The WECC assessment area is divided into six subregions: 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 subregional 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-US	RMRG	SRSG	2019	2020	2019 vs. 2020 SRA
Demand Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Total MW**	**Total MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,500	8,278	53,236	53,964	12,568	25,145	156,142	164,691	5.5%
Demand Response: Available	0	0	910	629	240	144	2,164	1,923	-11.1%
Net Internal Demand	11,500	8,278	52,326	53,335	12,328	25,001	153,979	162,768	5.7%
Resource Projections	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,356	11,471	63,186	62,770	16,068	29,440	194,208	197,292	1.6%
Tier 1 Planned Capacity	0	215	92	817	53	477	3961	1,653	-58.3%
Net Firm Capacity Transfers	0	0	0	749	0	0	0	749	0.0%
Anticipated Resources	14,356	11,686	63,278	64,336	16,122	29,917	198,169	199,694	0.8%
Existing-Other Capacity	0	0	0	0	0	0	0	0	0.0%
Prospective Resources	14,356	11,686	63,278	64,336	16,122	29,917	198,169	199,694	0.8%
Planning Reserve Margins	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Percent**	**Annual Difference**
Anticipated Reserve Margin	24.8%	41.2%	20.9%	20.6%	30.8%	19.7%	28.7%	22.7%	-6.0
Prospective Reserve Margin	24.8%	41.2%	20.9%	20.6%	30.8%	19.7%	28.7%	22.7%	-6.0
Reference Margin Level	10.4%	10.4%	13.7%	15.7%	13.0%	10.0%	15.4%	15.4%	0.0

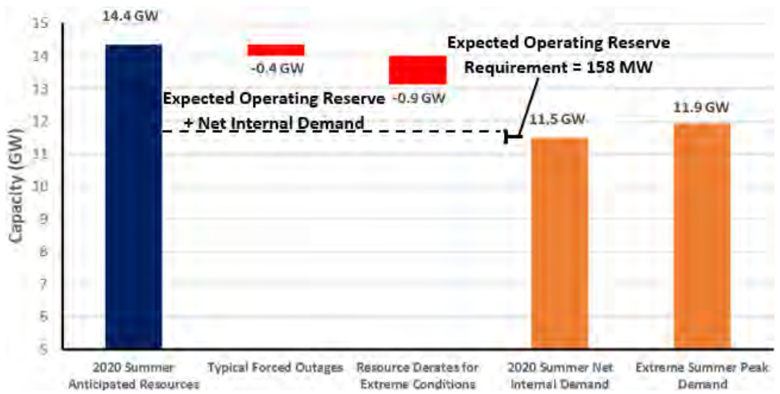
Highlights

- The existing and Anticipated Reserve Margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season.
- Below-normal hydro conditions are present in California that could reduce energy available from hydro resources throughout the summer. Hydro resources and imports from neighboring areas are important for maintaining system reliability in the California ISO area, where dispatchable generation has declined and variable generation is increasing. Extreme heat extending over California and neighboring areas could pose operating risk if surplus energy for import is reduced. Risks are heightened later in the summer when energy from hydro resources will be lower and solar PV output is near zero at the peak hour.
- Inventories of the Aliso Canyon Natural Gas Storage Facility (Aliso Canyon) remain an item of focus for electric reliability within the Western Interconnection. Going into the 2020 summer, the Southern California Gas Company (SoCalGas) system has more natural gas in storage and additional transmission lines in service, making it better postured to support natural gas users including electricity generators. SoCalGas estimates that it will be able to meet the forecasted peak day demand under a "best case" supply assumption even without supply from Aliso Canyon. Under a "worst case" supply assumption, the forecasted peak day demand cannot be met without curtailment even with the use of supply from Aliso Canyon.

The charts on the next page provide potential peak demand and resource condition information. The table above presents a standard seasonal assessment and comparison to the previous year's assessment. The waterfall charts on the next page present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. WECC entities determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized on the next page. See the Data Concepts and Assumptions for more information about the table and charts.

WECC-Alberta

Seasonal Risk Scenario

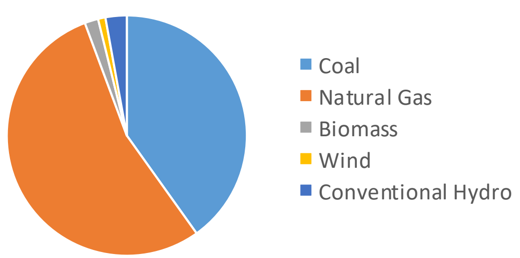


Risk Scenario Summary

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

Scenario Assumptions

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



WECC-British Columbia

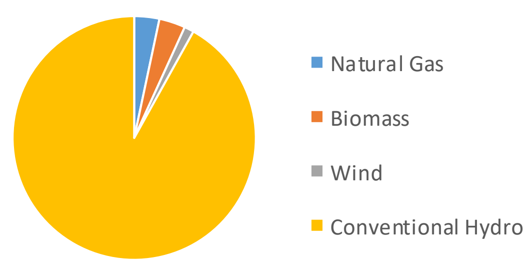
Seasonal Risk Scenario

Risk Scenario Summary

Resources meet operating reserve requirements under studied scenarios.

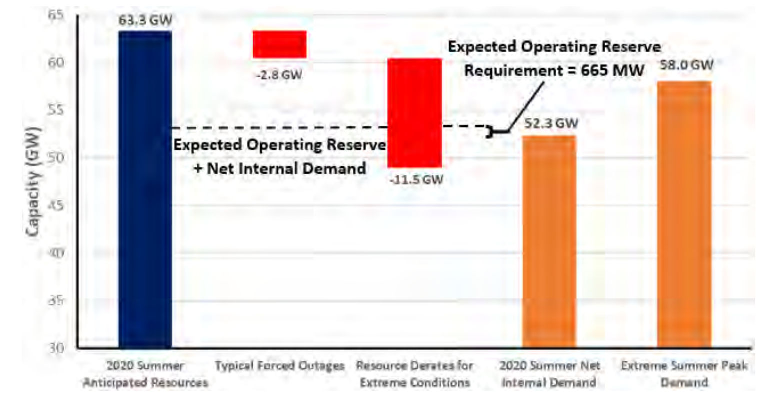
Scenario Assumptions

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



WECC-California / Mexico

Seasonal Risk Scenario

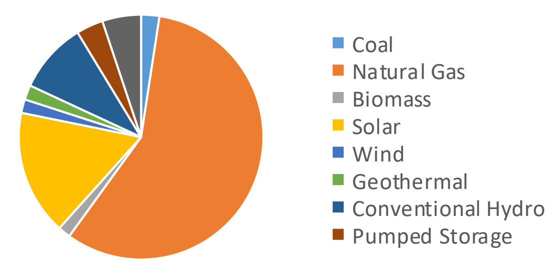


Risk Scenario Summary

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

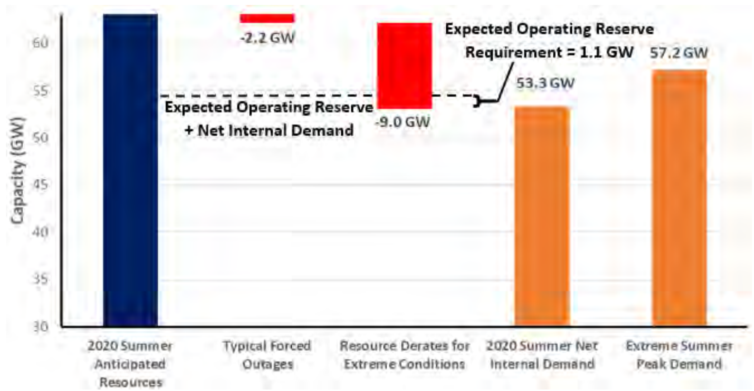
Scenario Assumptions

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



WECC-Northwest Power Pool

Seasonal Risk Scenario

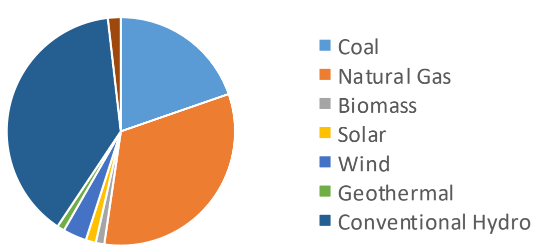


Risk Scenario Summary

Resources meet operating reserve requirements for normal peak-load and outage conditions. Operating mitigations and EEAs may be needed under extreme resource derated conditions.

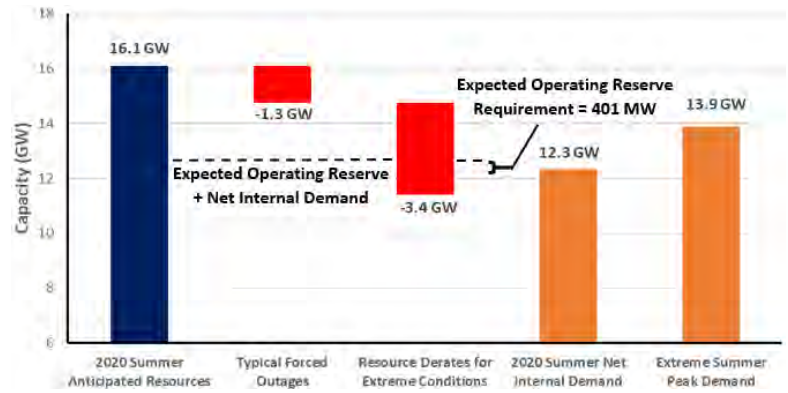
Scenario Assumptions

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



WECC-Rocky Mountain Reserve Sharing Group

Seasonal Risk Scenario

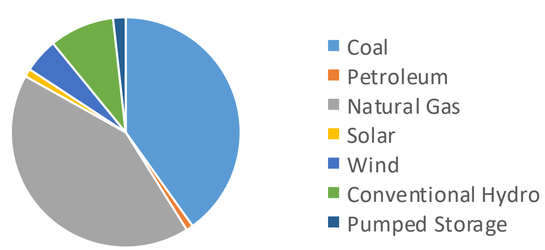


Risk Scenario Summary

Resources meet operating reserve requirements for normal peak-load and outage conditions. Operating mitigations and EEAs may be needed under extreme resource derated conditions.

Scenario Assumptions

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



WECC-Southwest Reserve Sharing Group

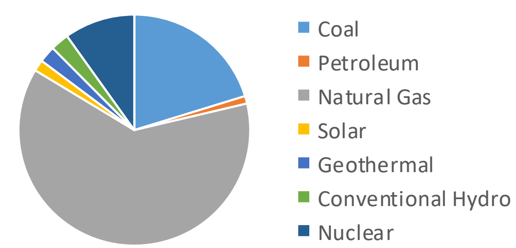
Seasonal Risk Scenario

Risk Scenario Summary

Resources meet operating reserve requirements for normal peak-load and outage conditions. Operating mitigations and EEAs may be needed under extreme resource derated conditions.

Scenario Assumptions

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



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.
• *2019 Long-Term Reliability Assessment* data has been used for most of this 2020 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[11] or total internal demand for the summer and winter of each year.[12]
• Total internal demand projections are based on normal weather (50/50 distribution[13]) and are provided on a coincident[14] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Table 2 below shows the wind and solar generation resources in each assessment area and describes how capacity contributions values are determined.
<u>Anticipated Resources:</u> • **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 summer 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.
<u>Prospective Resources</u>: 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.

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

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

[13] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[14] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

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 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 summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, 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 low-probability, extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer 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.

BPS Wind and Solar Generation Resources by Assessment Area

Assessment Area	Wind			Solar		
	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)
MISO	21,594	4,417	20.5%	663	390	58.8%
MRO-Manitoba Hydro	259	44	17.0%	0	0	-
MRO-SaskPower	241	55.8	23.2%	29	0	0.0%
NPCC-Maritimes	1,170	283	24.2%	2	0	0.0%
NPCC-New England	1,421	178	12.5%	200	119	59.5%
NPCC-New York	1,985	301	15.2%	57	16	27.7%
NPCC-Ontario	4,846	664	13.7%	478	66	13.8%

BPS Wind and Solar Generation Resources by Assessment Area						
Assessment Area	Wind			Solar		
	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/Nameplate (%)
NPCC-Quebec	3,904	0	0.0%	0	0	-
PJM	10,399	1,648	15.8%	4,684	2,415	51.6%
SERC-C	480	456	95.0%	10	8	80.0%
SERC-E	0	0	-	555	546	98.4%
SERC-FP	0	0	-	2,969.3	1,582.3	-
SERC-SE	0	0	-	2,266	2,259	99.7%
SPP	23,529	5,761	24.5%	272	201	73.9%
Texas RE-ERCOT	27,847	6,924	24.9%	3,735	2,838	76.0%
WECC-AB	1,445	142	9.8%	115	4.5	3.9%
WECC-BC	727.5	146	20.1%	2	0.6	30.0%
WECC-CAMX	6,773	1,097	16.2%	13,774	10,090	73.3%
WECC-NWPP-US	10,898	2,023	18.6%	5,831	883	15.1%
WECC-RMRG	3,852	774	20.1%	756	180	23.8%
WECC-SRSG	1,327	203	15.3%	1,698	458	27.0%

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2021 Summer Reliability Assessment

May 2021

Table of Contents

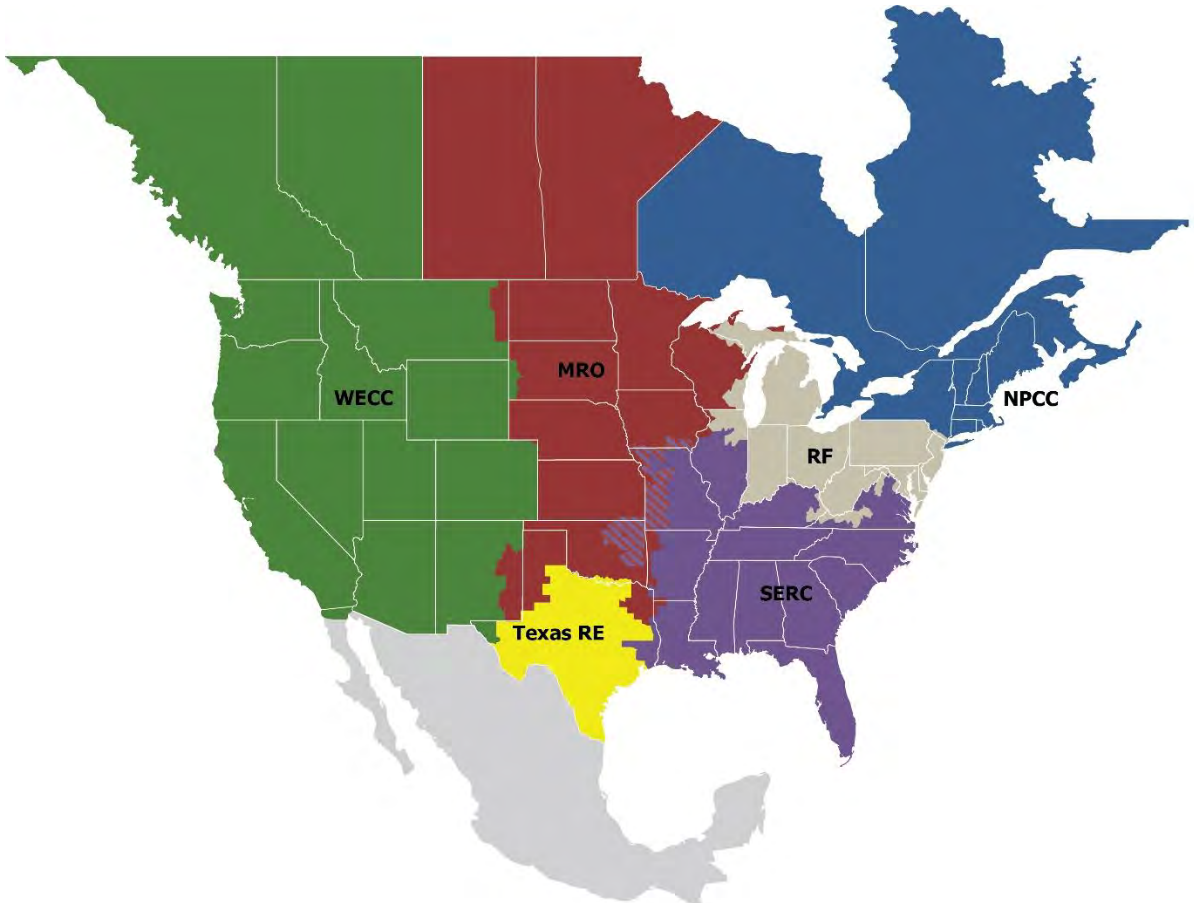
Preface

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 Report

NERC's *2021 Summer Reliability Assessment* (SRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the SRA 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 RE, and NERC staff. 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 summer period.

Findings

NERC's annual SRA covers Summer 2021 (June–September). This assessment provides an evaluation of the resource and transmission system adequacy that is necessary to meet projected summer peak demands. In addition to assessing resource adequacy, the SRA monitors and identifies potential reliability issues of interest and regional topics of concern. The following key findings represent NERC's independent evaluation of electric generation and transmission capacity as well as potential operational concerns that may need to be addressed for the upcoming summer:

- Parts of North America are at elevated risk to energy emergencies (see **Figure 1**). Above-normal heat in summer can challenge grid operators by increasing demand from temperature-dependent loads (such as air-conditioning and refrigeration) and reducing electricity supplies as a result of lower-than-capacity resource output or increased outages. Wide-area heat events (such as the August 2020 heat wave that affected much of the Western United States and Mexico) are especially challenging as fewer resources are available for electricity transfers between areas because they are required to serve native load:
  - In **Texas RE**, on-peak Planning Reserve Margins have increased to 15.3% from 12.9% last summer with the addition of 7,858 MW wind, solar, and battery resources since 2020. However, extreme weather can affect both generation and demand and cause energy shortages that lead to energy emergencies in the Electric Reliability Council of Texas (ERCOT). Furthermore, with a significant portion of electricity supply coming from wind generation, operators must have sufficient flexible resources to cover periods of low-wind output.
  - Across most of **WECC**, resource and energy adequacy is a significant concern for the summer with overall capacity and demand projections for the area at similar levels to those seen in 2020 when a wide-area heat event caused energy emergencies and managed firm load loss. Though new flexible resources have been added in California, peak demand projections have also increased in many parts of the west, and overall resource capacity is lower compared to 2020. Increasing demand and lower resource capacity across WECC can mean the availability of surplus capacity for transfer into stressed areas is declining.
  - **MISO** and **NPCC-New England** have sufficient resources for periods of peak demand. However, the above-normal levels of demand in the 90/10 forecast are likely to exceed capacity resources and require additional non-firm transfers from surrounding areas.
  - All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions. Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions.[1] Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate.

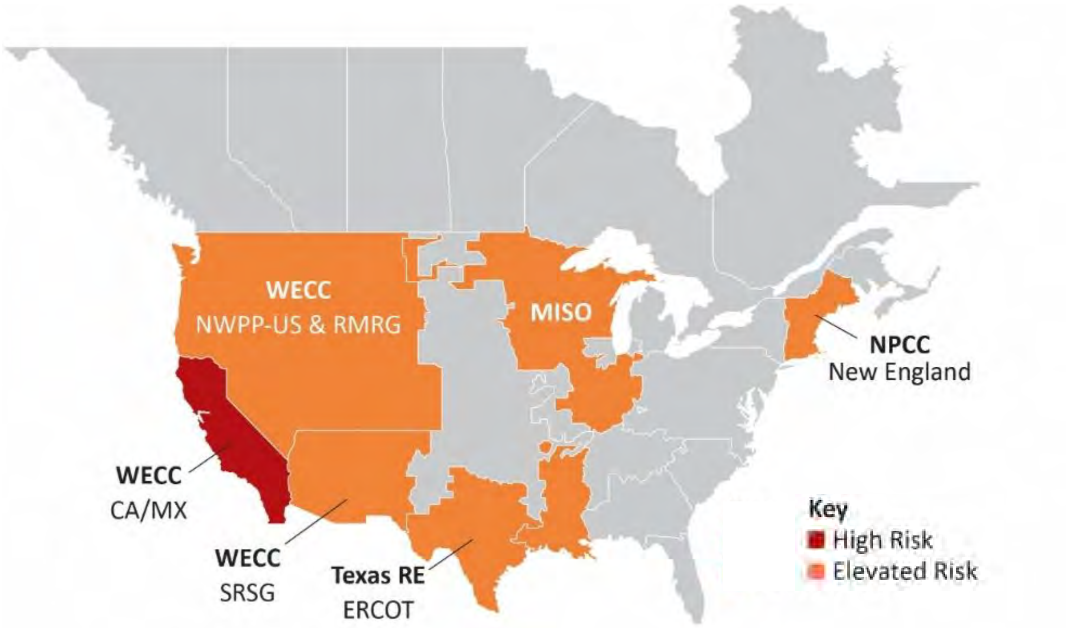


Figure 1: Energy Emergency Risk Areas

- **WECC-California is at risk of energy emergencies during periods of normal peak summer demand and high risk when above-normal demand is widespread in the west.** Prior to summer, the planning reserve margin (which is based on existing and firm capacity) for the California-Mexico assessment area was below the 18.4% Reference Margin Level that WECC calculates is

[1] For more information, see the description of the "Reference Margin Level" in the **Data Concepts and Assumptions** section of this report or refer to NERC's *Long-term Reliability Assessment*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

needed for maintaining loss-of-load risk below a 1-day-in-10-year benchmark (a 400 MW shortfall at peak demand). Probabilistic studies indicate 10,185 MWh of energy in the area is expected to go unserved this summer. Over 3 GW of additional resources are expected for this summer with most coming in the form of new solar photovoltaic (PV) generation. These generation plants can provide energy to support peak demand; however, solar PV output falls off rapidly in late afternoon while high demand often remains.

Imports to the area are needed to maintain reliability when demand peaks in the afternoon and to ramp up even further for several hours as internal resources draw down. California will have 675 MW of new battery energy storage systems on-line at the start of the summer that can continue to supply stored energy for periods when needed. Reliance on non-firm imports to cover high demand or low resource output conditions heightens the risk that operators will need to use energy emergency alerts (EEA)—and trigger the shedding of firm load in above-normal heat conditions—to maintain a stable BPS at times. Planned resource additions of 1,300 MW over the summer, including 825 MW of new battery storage, are expected to help mitigate late-summer risks.

- **Protecting the critical electrical workforce from health risks during pandemic remains a priority.** Protocols put in place for reducing risks to personnel in control centers and on the front lines, including mutual assistance in hurricane-damaged areas, should be maintained as warranted by public health conditions. Also related to the coronavirus (COVID-19) pandemic, operators must continue to give attention to daily load shapes that can be sensitive to changing behaviors of the workforce and commercial loads. In 2021, there is remaining uncertainty in demand projections as governments adjust to changing public health guidelines and conditions and as the behavior of society adapts.
- **The Late-summer wildfire season in Western United States and Canada poses risk to BPS reliability.** Government agencies warn of the potential for above-normal wildfire risk beginning in July in parts of the Western United States as well as Central and Western Canada.[2,3] Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions (see **Figure 3**).

Implications and Recommendations

The summer of 2021 is shaping up to be a challenge for electric system operators in many parts of North America, combining the resource situation described above with significant drought, fire, and high temperature risk assessments by independent agencies. In the near term, NERC recommends the following:

- Load-serving entities (LSE) and regulators work with their Balancing Authorities (BA) and Reliability Coordinators (RC) to ensure that clear lines of communication are open for coordination during periods of system stress. RC, BA, and Transmission Operators review outage schedules well in advance and coordinate across the RC area.
- BA and RC conduct drills on their alert programs to ensure that they are prepared to signal need for conservative operations, restrictive maintenance periods, etc. BA and Generator Operators verify protocols and operator training for communication and dispatch.
- LSE prepare for demand-side conservation measures and potentially condition customers to their need and efficacy.
- RC and BA maintain the highest vigilance during peak risk hours and forecasted high temperature periods.
- LSE review non-firm customer inventories and rolling black out procedures to ensure that no critical infrastructure loads (e.g., natural gas, telecommunications, etc.) would be affected.

Finally, the potential for these conditions to emerge were reflected in NERC's *2018* and *2020 Long-Term Reliability Assessments*; we recommend policy makers, system planners, LSE, and Generator Owners review these assessments and factor them into their integrated resource plans, and ISO/RTO factor them into their own generation queue management and long-range planning processes.[4]

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[2] See North American Seasonal Fire Assessment and Outlook, April 2021: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf.
[3] See Natural Resources Canada seasonal wildland fire forecasts: https://cwfis.cfs.nrcan.gc.ca/maps/forecasts
[4] NERC's Reliability Assessments web page: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is strongly influenced by temperature. Weather officials are expecting above normal temperatures for much of North America this summer (see Figure 2). Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as increases in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

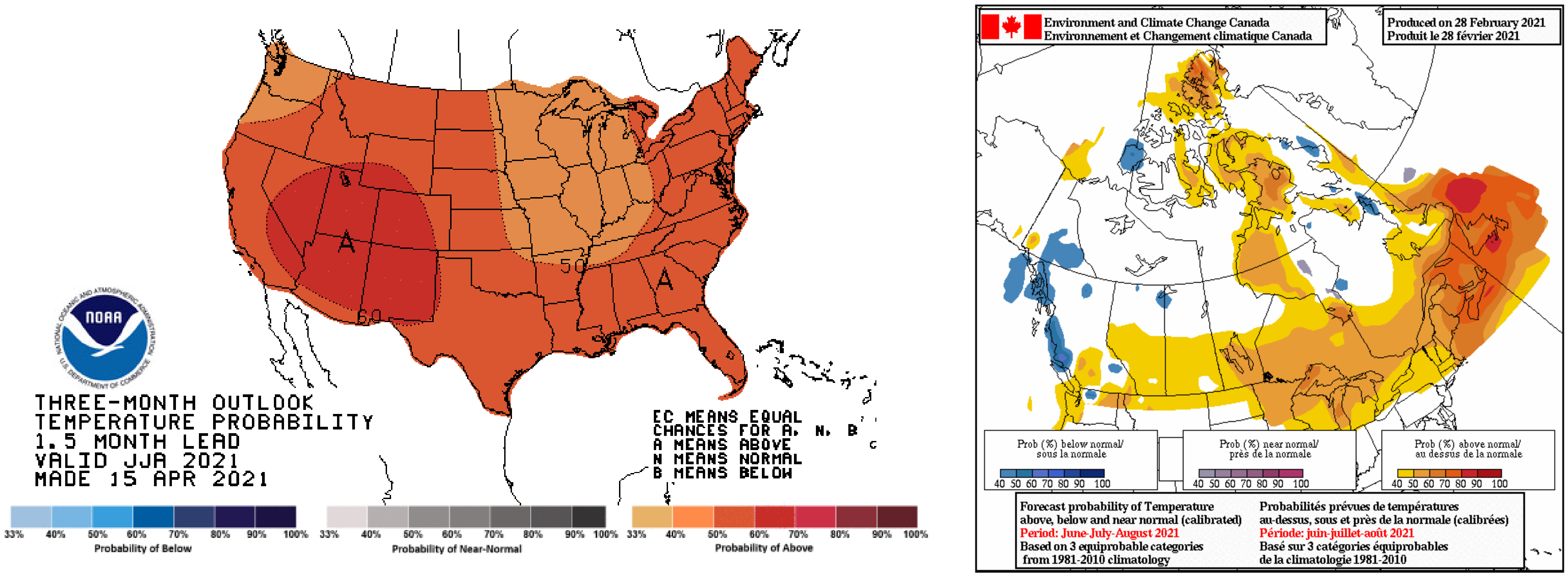

Figure 2: United States and Canada Summer Temperature Outlook[5]

[5] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Drought conditions extend over the western half of the United States and the middle-third of Canada. Above-normal fire risk at the beginning of the summer exists in the Southwest United States and over the middle-third of North America in the spring, setting the stage for an active fire season at the beginning of the summer (see **Figure 3**). Government agencies predict an active early fire season in the Southwest United States as well as above-normal risk in the lower half of central Canada (Southern Prairies, Boreal forest, grassland and parkland areas).[6] In late summer, hotter and drier conditions are expected to cause elevated fire risk in California and the United States West Coast. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions (see **Finding: Risk Discussion**).

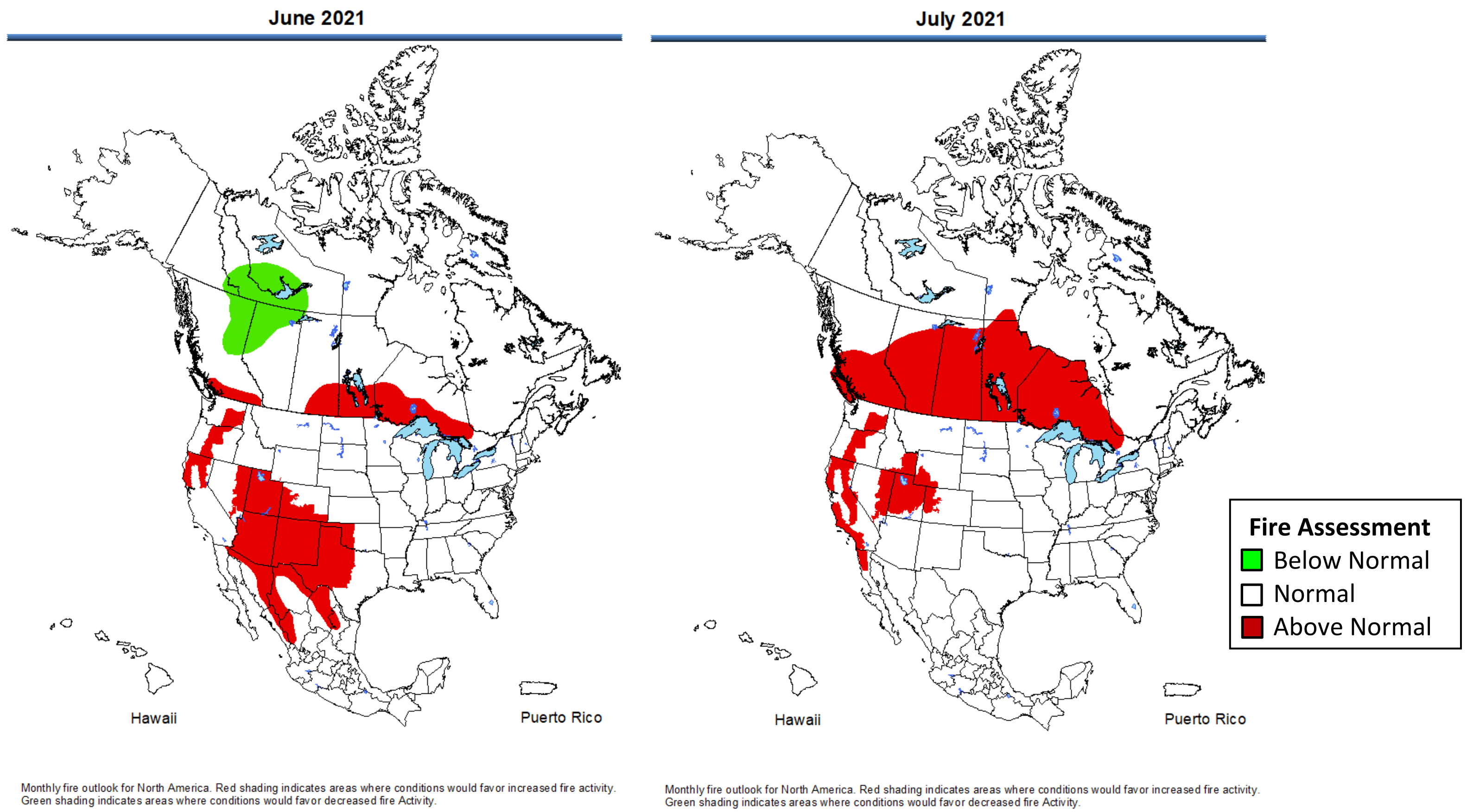

Figure 3: North American Seasonal Fire Assessment for June and July 2021

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[6] See North American Seasonal Fire Assessment and Outlook, April 2021: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

Finding: Risk Discussion

Texas RE: ERCOT Interconnection

With forecasted growth in peak demand and new generation resources primarily coming in the form of variable wind and solar generation, the risk of shortages that lead to energy emergencies in ERCOT continues for the upcoming summer. On-peak Planning Reserve Margins have increased to 15.3% from 12.9% last summer with the addition of 7,858 MW wind, solar, and battery resources since 2020; This exceeds the 13.75% Reference Margin Level established in ERCOT for reliably serving demand under normal summer peak conditions. However, extreme weather can affect both resource and demand and cause energy shortages that lead to energy emergencies in ERCOT. Furthermore, with a significant portion of electricity supply coming from wind generation, operators must have sufficient flexible resources to cover periods of low-wind output (see Figure 4 for a risk scenario involving 90/10 low wind conditions and normal 50/50 peak demand). Operational mitigations may be needed in unexpected wind generation shortfalls to avoid energy emergencies.

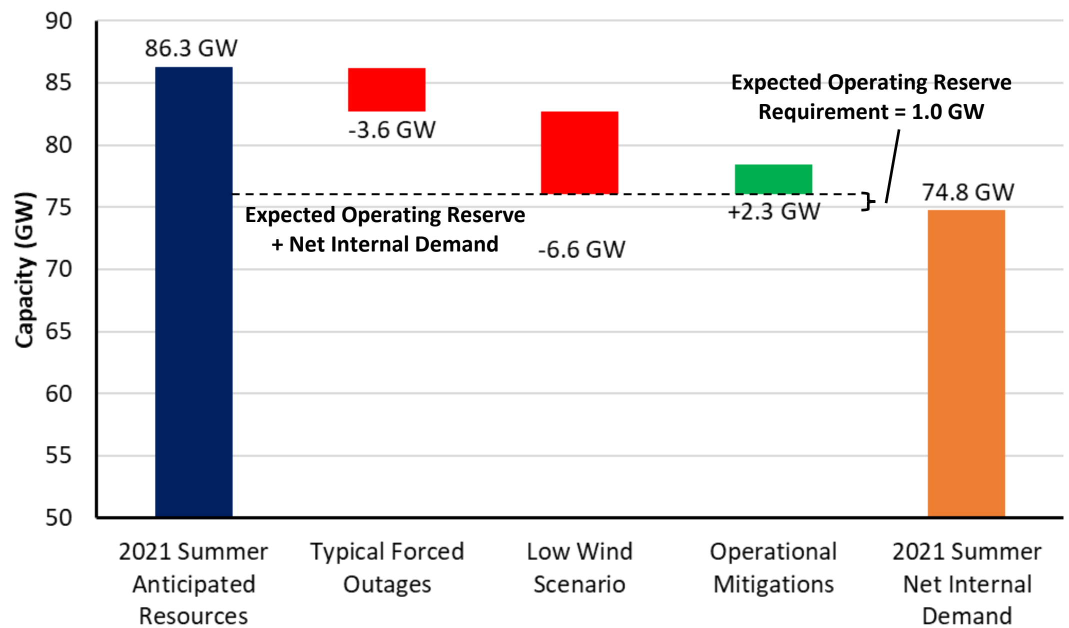

Figure 4: Combination of Low-Wind and Normal Generator Outages at Peak Demand in ERCOT

Weather conditions can create an elevated risk of operating emergencies in ERCOT in the event that higher demand or lower resource output diminishes the relatively low reserve margins that exist on the system. Shown in Figure 5 are the 1-in-10 year high demand levels alongside an extreme low-resource scenario: 12.1% of expected thermal resources are unavailable as well as 76.8% reduced output of expected wind (this is 6.2% of the total installed nameplate wind capacity operating). Combinations of high peak demand and extreme low resource output are exceedingly rare; however, they are plausible and provide industry and stakeholders with insights into potential emergency conditions. The result of the described scenario is a 12.7 GW shortfall. In challenging conditions like those depicted, operators would resort to implementing rotating outages as a measure of preserving the BPS.

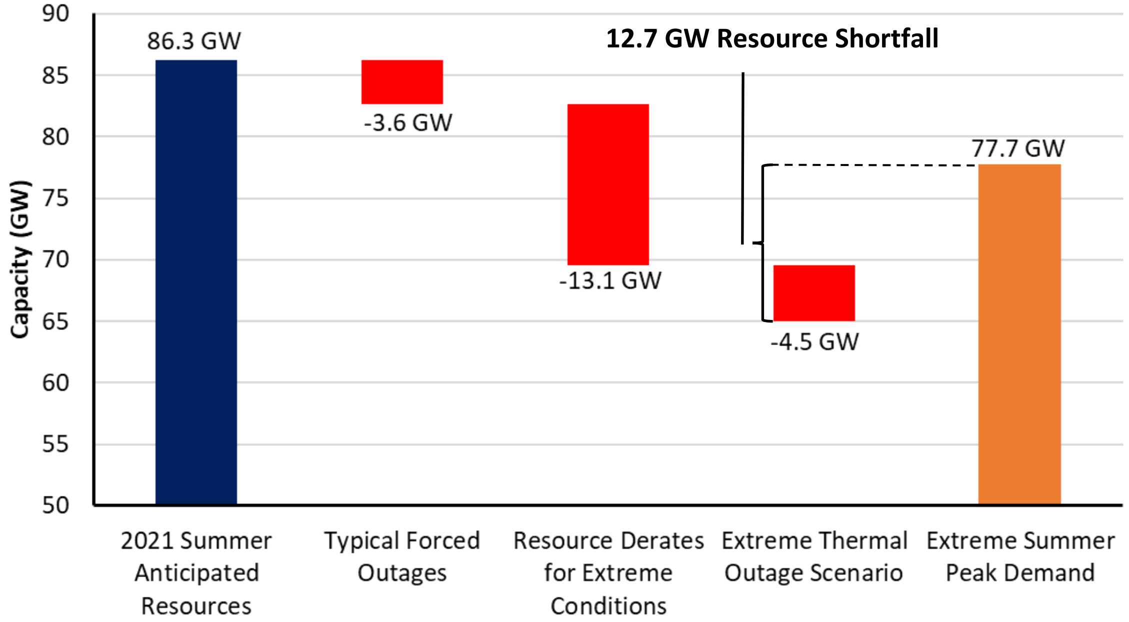

Figure 5: Impact of Extreme Demand and Resource Outages in ERCOT

In addition to the 1-in-10 year demand scenario above, ERCOT conducted an additional extreme demand scenario based on a wide-area heat event. In this scenario, peak demand increases by over 4,900 MW from a normal 50/50 demand forecast as all of ERCOT's eight weather zones show simultaneous high levels of demand from higher temperatures. Even with the normal resource performance and low outages typically seen in ERCOT, the electricity demand from a wide-area heat event would likely lead to operating emergencies and a potential for unserved load.[7]

Currently, much of Texas is experiencing a drought, and projections for below-normal rainfall are cause for concern for electric reliability.[8] If drought conditions continue to deteriorate, the likelihood of the actual summer peak demand exceeding the forecast and/or generation derates due to low cooling lake levels increases. Generator outages are expected to increase during severe and prolonged drought conditions due to cooling water supply and temperature issues. These issues can cause forced outages of the thermal and wind fleet.

Generator performance in ERCOT is optimized for summer conditions, supporting reliable system performance despite relatively lower reserve margins. The generation fleet in ERCOT is a diverse mix of fuel types, including natural gas, nuclear, on-shore and coastal wind, solar, and a small amount of coal-fired generation. Some design choices, such as open-air thermal plants, provide optimum summer efficiency but may contribute to operating stress at other times. The availability of reliable, flexible generation is important to balancing system needs with a high penetration of variable, weather-dependent generation from wind and solar.

[7] See ERCOT's *2021 Summer Seasonal Assessment of Resource Adequacy (SARA)*: http://www.ercot.com/content/wcm/lists/219840/SARA-FinalSummer2021.pdf
[8] https://droughtmonitor.unl.edu/CurrentMap/StateDroughtMonitor.aspx?TX

WECC: Western Interconnection

Resource and energy adequacy is a significant concern for the summer across most of the Western Interconnection with overall capacity and demand projections for the area at similar levels to those seen in 2020 when a wide-area heat event caused energy emergencies and managed firm load loss. New flexible resources have been added in California and some plans for generation retirements have been put on hold to improve resource availability for periods of peak demand as well as for times when variable generation output falls off. However, peak demand projections have also increased in many parts of the Western United States, and overall resource capacity is lower compared to 2020 (see **Table 1**). Increased demand and lower resource capacity across the Western Interconnection can mean limited availability of surplus capacity for transfer into load centers for parts of California.

August 2020 Heatwave Event in the Western Interconnection

From August 14 through August 19, 2020, the Western United States suffered an intense and prolonged heatwave that affected many areas across the Western Interconnection.[9] Because of above-average temperatures, generation and transmission capacity struggled to keep up with increased electricity demand. Throughout many supply-constrained hours over this same period, generation resource output was below preseason peak forecasts for nearly all resource types, including natural gas, wind, solar, and hydro. During the event, 10 Western Interconnection BA issued 18 separate EEA. The impacts of the August heatwave struck the entirety of the Western Interconnection and caused a peak demand record of 162,017 MW on August 18, 2020, at 4:00 p.m. Mountain time. Although demand peaked on August 18, the most severe reliability consequence of the heatwave event occurred at the beginning, when 1,087 MW of firm load was shed on August 14 and 692 MW was shed on August 15 in California. An in-depth evaluation of the August 2020 Heatwave Event on BPS operations will be included in the 2021 State of Reliability report. The State of Reliability covers significant BPS events from the prior year and is typically published mid-year.

Table 1: Western Interconnection On-Peak Resource Adequacy

WECC - AB			
	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	11,500	10,886	-5.3%
Net Internal Demand	11,500	10,886	-5.3%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	14,356	12,205	-15.0%
Anticipated Resources	14,356	13,928	-3.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	24.8%	27.9%	3.1
Reference Margin Level	10.4%	9.7%	-0.7
WECC - BC			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	8,278	8,264	-0.2%
Net Internal Demand	8,278	8,264	-0.2%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	11,471	11,178	-2.6%
Anticipated Resources	11,686	11,363	-2.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference

[9] WECC August Heat Wave Event information provided by WECC's *August Heat Wave Analysis* Presentation

Table 1: Western Interconnection On-Peak Resource Adequacy			
Anticipated Reserve Margin	41.2%	37.5%	-3.7
Reference Margin Level	10.4%	9.7%	-0.7
WECC - CA / MX			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	53,236	55,409	4.1%
Net Internal Demand	52,326	54,487	4.1%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	63,186	63,396	0.3%
Anticipated Resources	63,278	67,440	6.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	20.9%	23.8%	2.9
Reference Margin Level	13.7%	18.4%	4.7
WECC - NWPP-US & RMRG			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	66,532	67,117	0.9%
Net Internal Demand	65,664	66,030	0.6%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	78,839	70,069	-11.1%
Anticipated Resources	80,457	77,210	-4.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	*	16.9%	*
Reference Margin Level	*	14.3%	*
WECC - SRSG			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	25,145	24,751	-1.6%
Net Internal Demand	25,001	24,419	-2.3%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	29,440	26,850	-8.8%
Anticipated Resources	29,917	27,904	-6.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	19.7%	14.3%	-5.4
Reference Margin Level	10.0%	9.8%	-0.2

Responding to supply shortages from August 2020 and a directive from the California Public Utilities Commission, utilities in California have been procuring additional generating capacity for Summer 2021.[10] Existing on-peak capacity for the California-Mexico (CAMX) assessment area is 63.4 GW, a slight increase from 2020. However, a total of 3.4 GW of new resources are in late-stage planning for addition this summer; without these resources, the CAMX area will have an on-peak planning reserve margin of 17.6%, just short of the 18.4% Reference Margin Level target set by WECC for the area.[11] See **Figure 6** for peak hour existing certain and anticipated resource reserve margins for the Western Interconnection assessment areas.

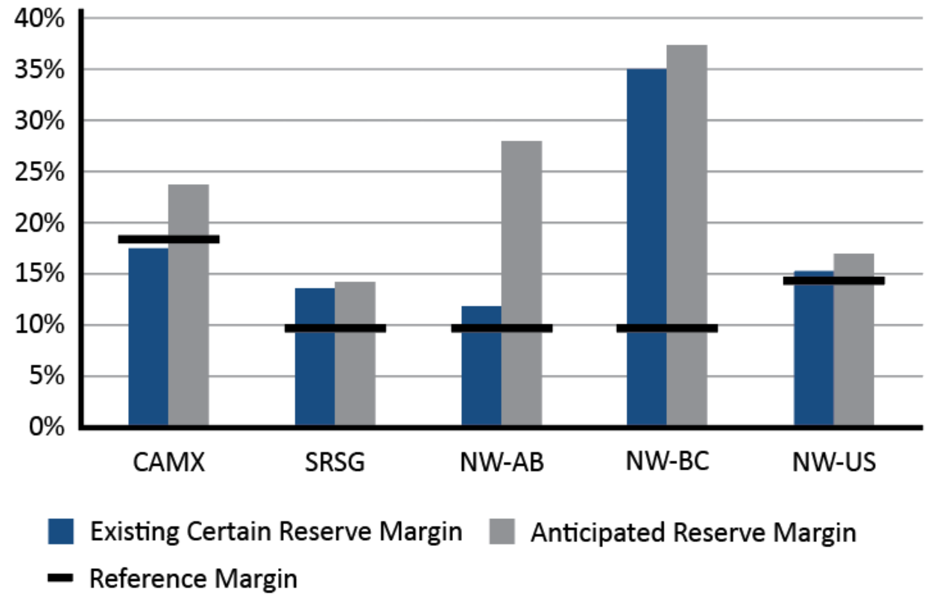

Figure 6: On-Peak Planning Reserve Margins in the Western Interconnection Assessment Areas

Most of the resource additions in California come in the form of new solar PV generation. These generation plants can provide energy to support peak demand; however, solar PV output falls off rapidly in late afternoon while summer demand often remains (see the discussion in the **Western Interconnection Risk Scenarios** section). Battery storage systems can supply energy to smooth the system ramping needs associated with high amounts of variable generation; by summer, nearly 600 MW of large-scale battery storage projects will have come on-line in California with an additional 800 MW expected by August 1.[12] The California Independent System Operator (CAISO) has performed significant work to support the integration of these new technologies into market and operating systems so that they will enhance grid reliability.

Throughout the Western Interconnection, BAs rely on flexible resources to support balancing the increasingly weather-dependent load with the variable generation within the resource mix. Dispatchable generation from hydroelectric and thermal plants internal to the BA's area as well as imports from surplus energy in another area are called upon by operators when area shortfalls are anticipated. Under normal

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[10] See California Public Utilities Commission Emergency Reliability Rulemaking R.20-11-003

[11] WECC's Reference Margin Levels are based on a probabilistic approach for Loss-of-Load Probability (LOLP) less than or equal to 0.02% (approximately a 1-day-in-10-year loss of load). For more information see the *NERC 2020 Long-Term Reliability Assessment (LTRA)* Table 10: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

[12] A summary of resource additions in the CAISO area is found in Table 10 of the *CAISO Summer Loads and Resources Assessment, May 2021*: http://www.caiso.com/Documents/2021-Summer-Loads-and-Resources-Assessment.pdf

conditions, there is sufficient energy and resource capacity and an adequate transmission network for transfers between areas to meet system ramping needs. However, conditions such as wide-area heat events can reduce the availability of resources for transfer as areas serve higher internal demands. Additionally, transmission networks can become stressed when events such as wildfires or wide-area heatwaves cause network congestion. The growing reliance on transfers within the Western Interconnection and falling resource capacity in many adjacent areas increases the risk that extreme events will lead to load interruption.

Western Interconnection Risk Scenarios

Probabilistic studies performed by WECC identified a continued risk of energy shortfalls. For the upcoming summer, the WECC-CAMX area has 10,180 MWh of expected unserved energy (EUE) and the Northwest Power Pool and the Rocky Mountain Reserve Sharing Group (WECC-NWPP & RMRG) has 3,442 MWh of EUE; all other WECC areas have negligible EUE. WECC examined risk across a wide probability spectrum of potential combinations of high loads and low generation levels, with and without dependency on neighboring BA areas, and how deviations from those expected means would affect reliability.[13] The risk analysis charts in the **Regional Assessments Dashboards** illustrate the potential for above-normal peak demand and resource outage scenarios, similar to those seen in 2020, to result in operating emergencies in all WECC assessment areas with the exception of the winter-peaking Canadian provinces. For example, **Figure 7** is for the WECC CAMX area. Wide-area heatwave events can heighten energy shortfall risks throughout the Western Interconnection by reducing the availability of surplus capacity for sharing or by loading the transmission network to the limits of its transfer capability.

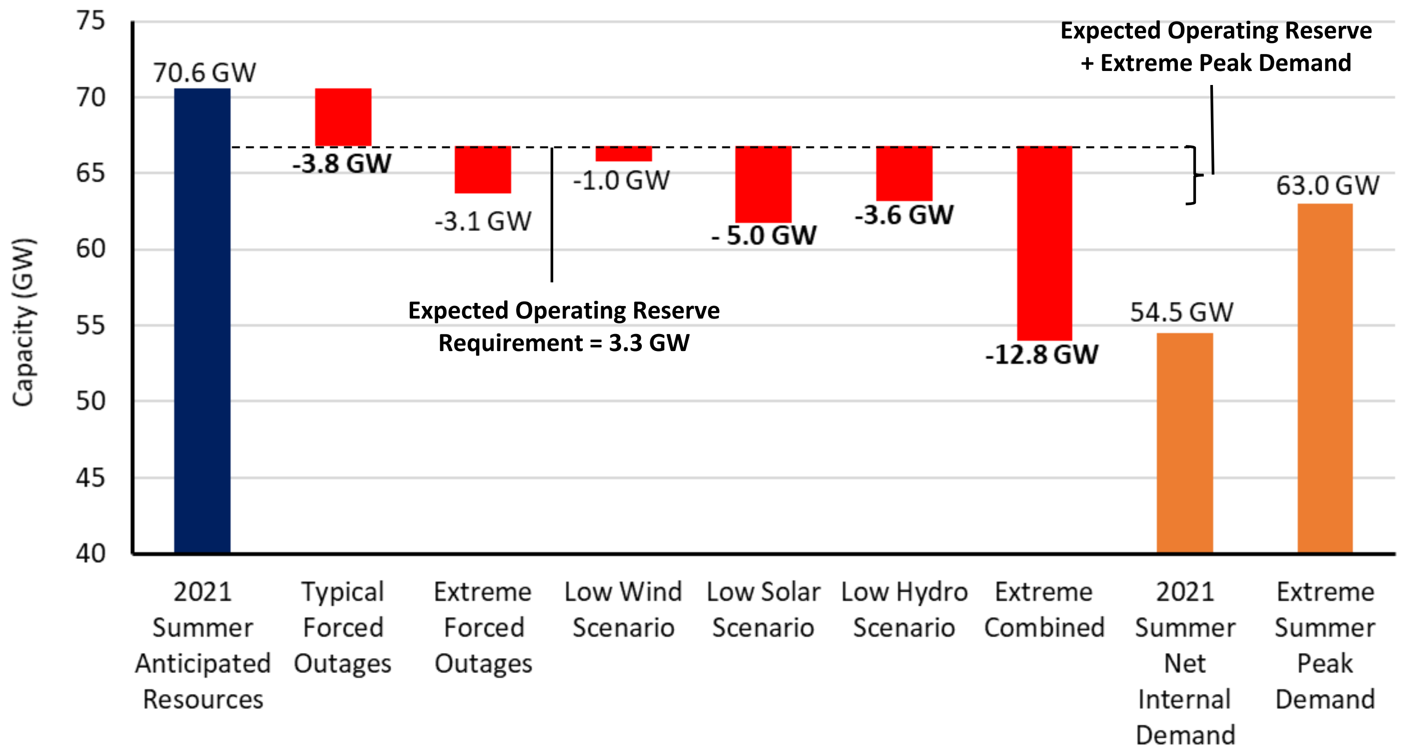


Figure 7: CAMX On-Peak Risk Scenario

[13] See *Western Assessment of Resource Adequacy Report*: Western Assessment of Resource Adequacy Report 12-18 (Final).pdf.pdf (wecc.org)

In summer, CAMX can be exposed to greater risk of resource shortfall for the hours that immediately follow the peak demand. The reason the risk is greater in these hours is that solar resource output is rapidly diminishing with the setting sun. Shown in the scenario depicted in Figure 8, anticipated resources are lower than on peak due to the reduced solar PV outputs. During periods of peak demand and normal forced outages, imports provide the needed energy to ensure demand and operating reserve requirements are met. Demand or resource derates from extreme conditions that cannot be satisfied with imports will result in energy emergencies and the potential for load shedding. Though trends for off-peak risk are increasing in other parts of the Western Interconnection, WECC's analysis indicates that greater risk exposure after the demand peak is only exhibited in CAMX.

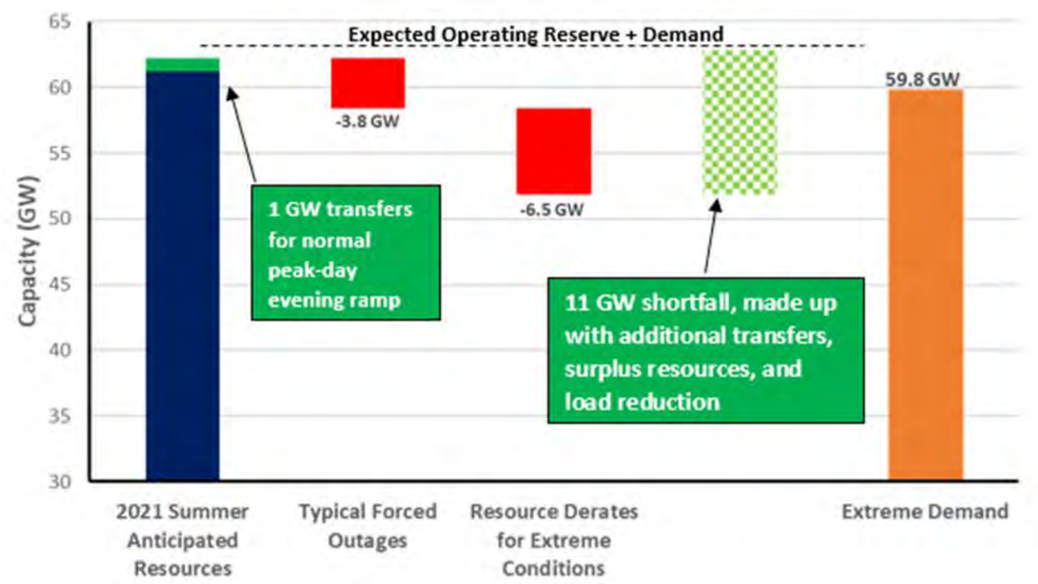


Figure 8: CAMX Highest Risk Hour Scenario (Hour Ending 7:00 p.m. Pacific Time)

Given that little has changed in the available electricity resources and the expected demand throughout the Western Interconnection, the summer-peaking areas remain at risk for localized shortfalls to exceed the availability of resource assistance and transmission deliverability during events like the 2020 August wide-area heat wave. Early generation and load forecasting based on long-term meteorological conditions will be important to maximize available generation and prepare load management plans for challenging weather. Enhancements to day-ahead markets and operational planning that were put in place and were effective in mitigating the impacts of the second, higher temperature heat wave that extended across the Western United States in September 2020 will need to be employed again to support BPS reliability in similar conditions.

Wildfire Impacts to the BPS in the Western Interconnections

Operation of the BPS can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. Wildfire prevention planning in California and other areas include power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the Electric Reliability Organization published the *Wildfire Mitigation Reference Guide*[14] to promote preparedness within the North American electric power industry and share the experience and practices from utilities in the Western Interconnection.

On-Peak Planning Reserve Margins

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 forecasted peak demand.[15] Large year-to-year changes in anticipated resources or forecasted 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 Summer 2021 (see **Figure 9**). Variable energy resources, including wind, solar, and types of hydro generation, often contribute significantly less of their installed capability at the period of peak demand. Consequently, the capacity contribution of variable energy resources to an areas anticipated resources may be a fraction of the installed capacity (see **Variable Energy Resource Contributions**).

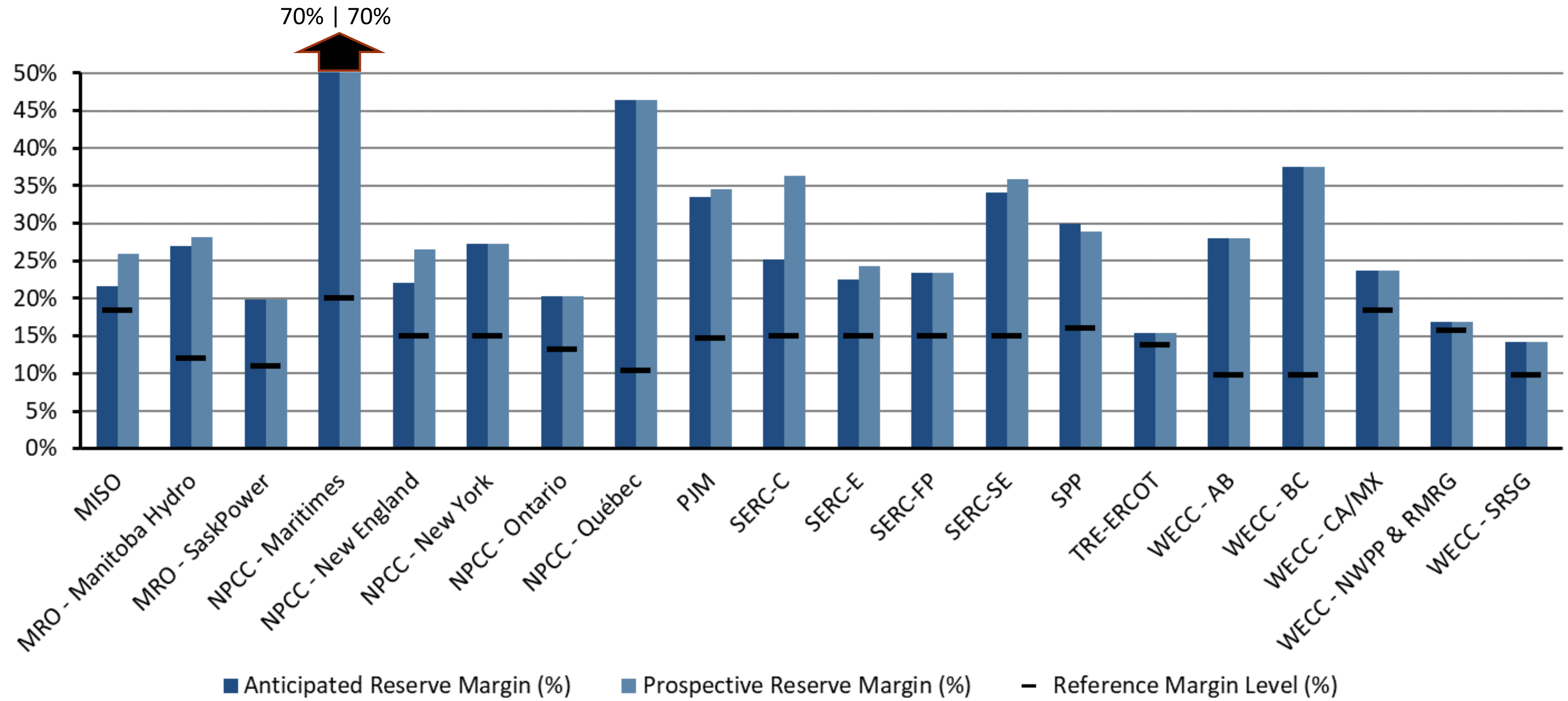


Figure 9: Summer 2021 Anticipated / Prospective Reserve Margins Compared to Reference Margin Level

[14] See the NERC Wildfire Mitigation Reference Guide, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

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

Changes from Year-to-Year

Understanding the changes from year-to-year can give insights for the upcoming season. Figure 10 provides the relative change from the Summer 2020 to the Summer 2021 period. The assessment area tables in the Demand and Resource Tables section provide details of the demand and resource components that make up the Anticipated Reserve Margins for each assessment area. In the following areas, Anticipated Reserve Margin changed by more than five percentage points, and none of the changes result in a resource adequacy concern for the upcoming summer:

- **MRO-Manitoba Hydro:** New hydro generators begin operation in May and July.
- **NPCC-Maritimes:** A decrease in demand-side management availability accounts for the majority of Anticipated Reserve Margin loss for the Maritimes footprint.
- **NPCC-New England, Québec, and WECC-SRSG:** Resources have fallen year-on-year with generation retirements.

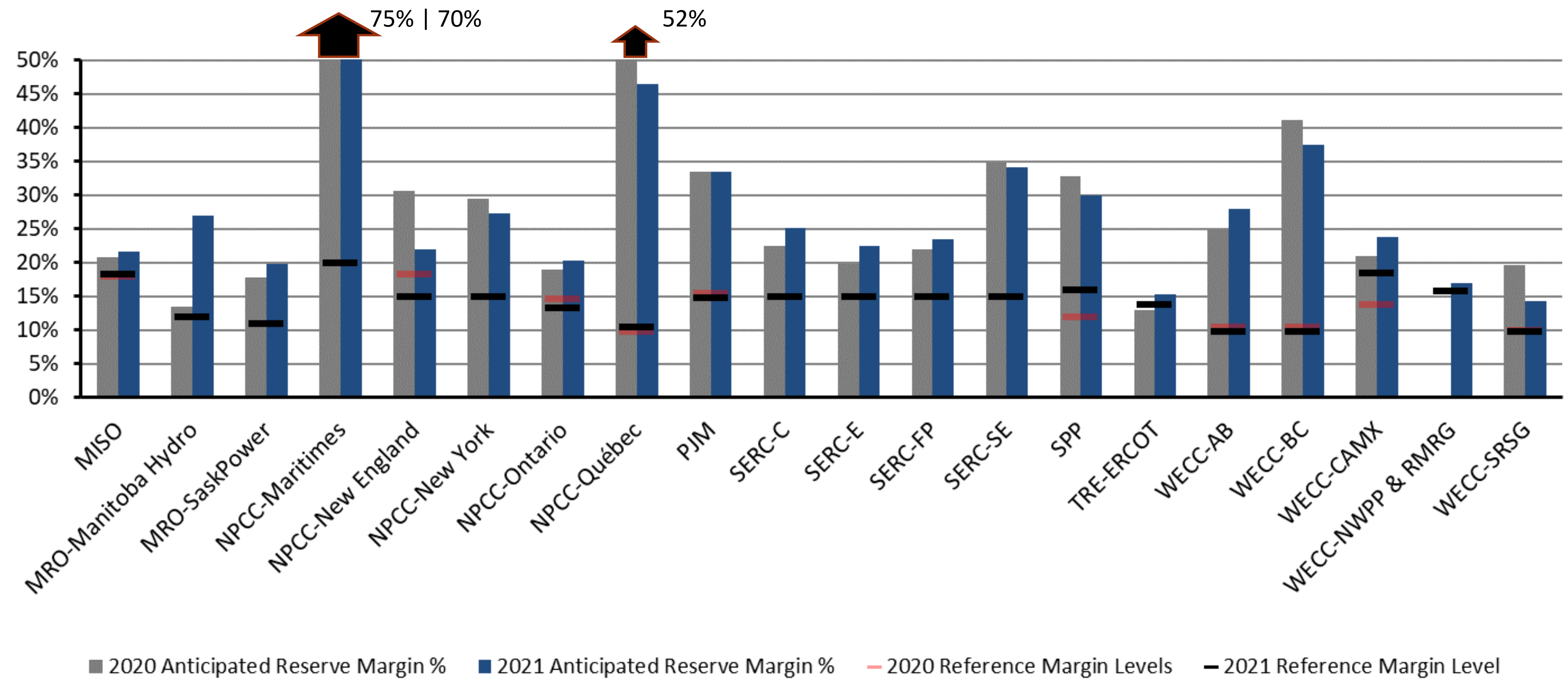


Figure 10: Summer 2020 to Summer 2021 Anticipated Reserve Margins Year-to-Year Change[16]

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

Risk Assessments of 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. Grid operators employ operating mitigations or EEA (see **Table 2**) to obtain resources necessary to meet peak demands when operating resources are insufficient. The **Regional Assessments Dashboards** section in this report includes a seasonal risk scenario for each area that illustrates potential variation in resource and load as well as the potential effects that operating actions can have to mitigate shortfalls in operating reserves when insufficiencies occur.

About the Seasonal Risk Assessment

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. 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 SRA 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 events are also factored in through additional resource derates or low-output scenarios and extreme summer 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.

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 BS 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 Event

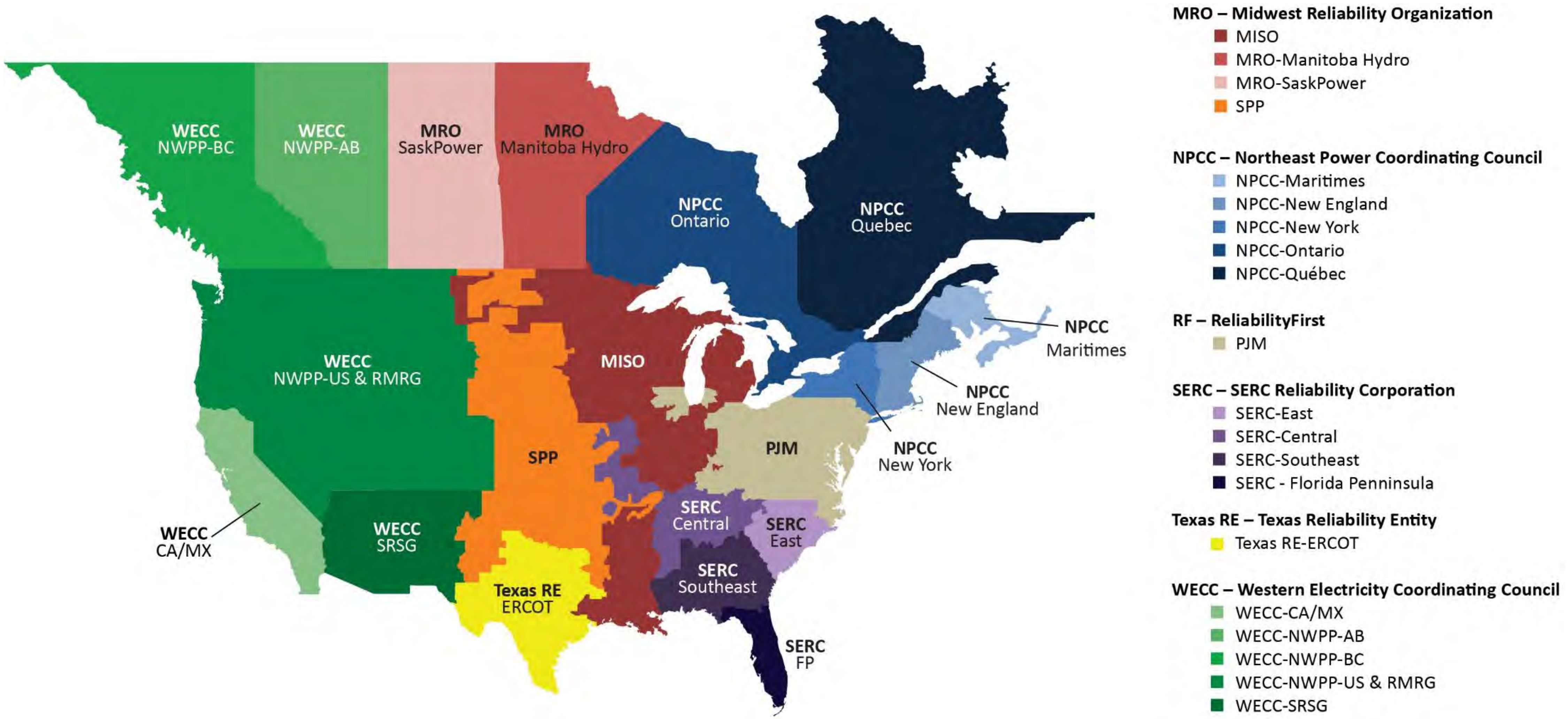
When above-normal temperatures extend over a wide area, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Some assessment areas expect imports from other areas to be available to meet periods of peak demand and have contracted for firm transfer 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 summer seasons are shown in **Table 3**; the data in this table is sourced from the data adequacy tables in the **Data Concepts and Assumptions** section. In the unlikely event that multiple assessment areas are experiencing energy emergencies as could occur in a wide-area heatwave, 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.

Table 3: 2020 and 2021 On-Peak Net Firm Transfers

Assessment Area	2020 Summer Transfers (MW)	2021 Summer Transfers (MW)	Year-to-Year Change
MISO	2,795	2,979	6.6%
MRO-Manitoba	-1,526	-1,596	4.6%
MRO-SaskPower	125	125	0.0%
NPCC-Maritimes	-53	-57	7.5%
NPCC-New England	1,510	1,208	-20.0%
NPCC-New York	1,562	1,816	16.3%
NPCC-Ontario	0	80	N/A
NPCC-Quebec	-1,963	-1,995	1.6%
PJM	1,412	1,460	3.4%
SERC-C	-807	172	-121.3%
SERC-E	266	562	111.3%
SERC-FP	1,146	1,007	-12.1%
SERC-SE	-972	-1,115	14.7%
SPP	-1,244	186	-115.0%
TRE-ERCOT	817	210	-74.3%
WECC-AB	0	0	N/A
WECC-BC	0	0	N/A
WECC-CAMX	0	686	N/A
WECC-NWPP-US and RMRG	749	6,139	719.6%
WECC-SRSG	0	866	N/A

Regional Assessments Dashboards

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

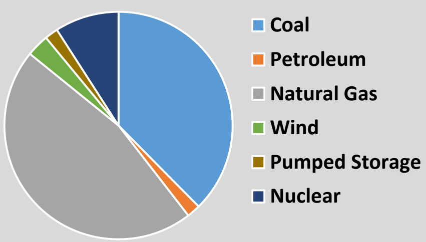


MISO

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 NERC RE, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Fuel Mix



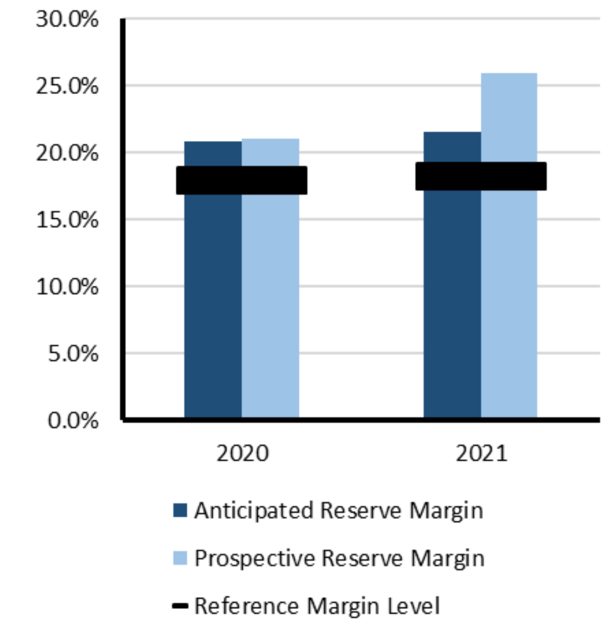
Highlights

- Summer scenarios with high resource outages and high demand may require use of load modifying resources (LMRs) and non-firm imports during peak periods. LMRs are an increasingly important segment of MISO resource portfolio. Operators designate resource constrained periods (Maximum Generation Events) to access LMRs.
- All MISO zones have met local capacity clearing requirements in the wholesale market auction and are projected to have sufficient resources for the summer.
- Covid-19 impacts on MISO load through late 2020 and the first quarter of 2021 have been much less pronounced than they were at the beginning of the pandemic. During the pandemic, MISO load has run 1–2% below normal in mild weather and 1–2% above normal in hotter weather. MISO expects load to trend close to normal through the summer; however, during a heatwave, load could trend 1–3% above normal due to increased residential demand.
- Based on probabilistic studies performed by MISO, the area has low amounts of EUE (18.6 MWh) for the summer season. Greatest risk occurs in the month of July, coinciding with the typical peak in annual demand.

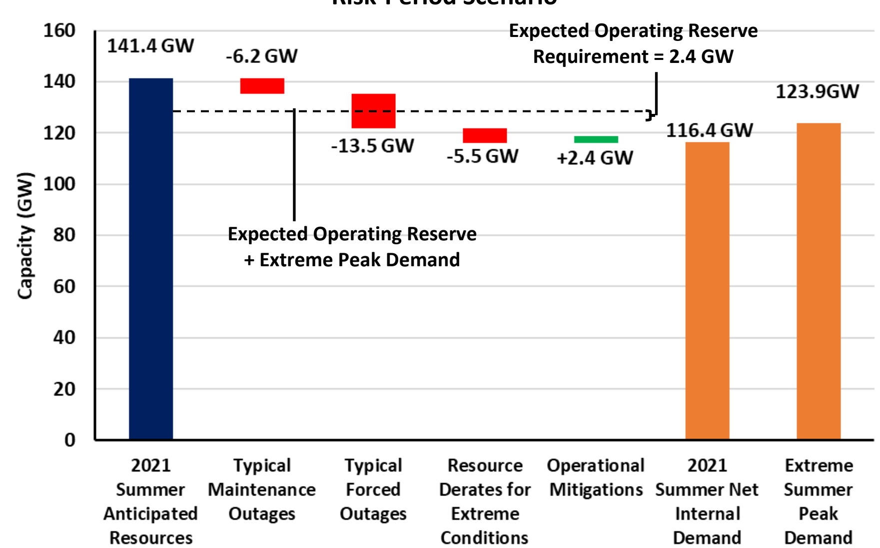
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

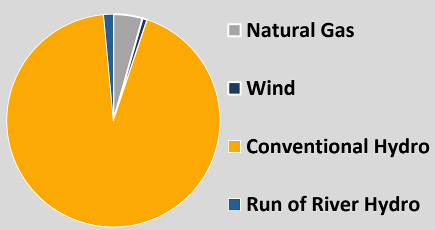
- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon).
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast using 30 years of historical data
- **Maintenance Outages:** Rolling five-year average of maintenance and planned outages
- **Forced Outages:** Five-year average of all outages that were not planned
- **Extreme Derates:** Maximum of last five years of outages
- **Operational Mitigation:** 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 BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

On-Peak Fuel Mix

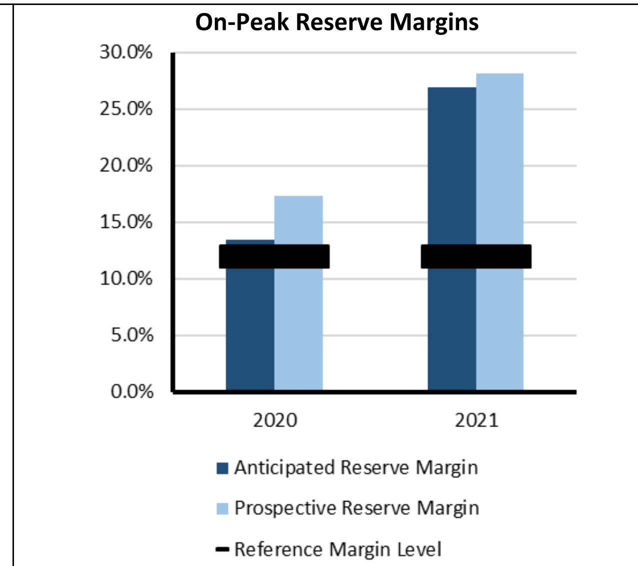


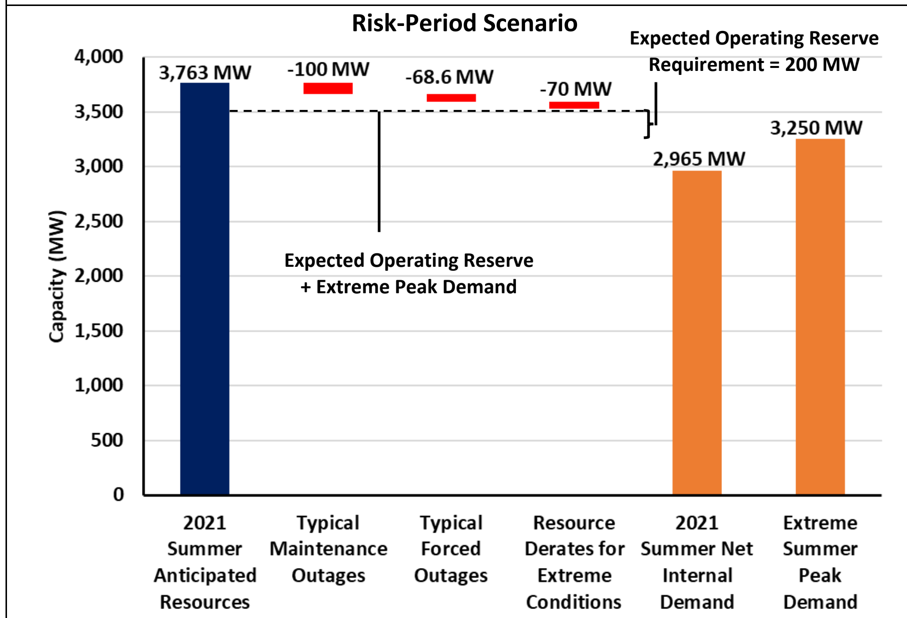
Highlights

- While the COVID-19 pandemic is expected to continue over the summer, no impact on area BPS reliability is anticipated as Manitoba Hydro has measures in place to minimize risk to operations. As of mid-March 2021, the pandemic situation in Manitoba appears stable with the implemented government measures.
- Reservoir storage levels are average and adequate to withstand the design drought.
- The first of seven Keeyask units is expected in May and the second is expected by July 1, 2021 (93 MW per unit).
- Based on the NERC 2020 Probabilistic Assessment (ProbA) and analysis of summer demand and resources, Manitoba Hydro is unlikely to experience resource shortages requiring operating procedures over the summer.

Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.





Scenario Description

- **Risk Period:** Periods of peak demand
- **Demand Scenarios:** Net internal demand (50/50) and minimum probability of exceedance forecast load
- **Outages:** Accounts for planned maintenance and average forced outages
- **Extreme Derates:** Capacity derate for thermal resources for extreme conditions.

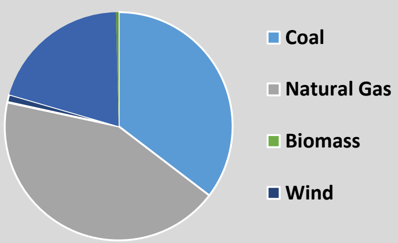
MRO-SaskPower

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 (BES) and its interconnections.

On-Peak Fuel Mix



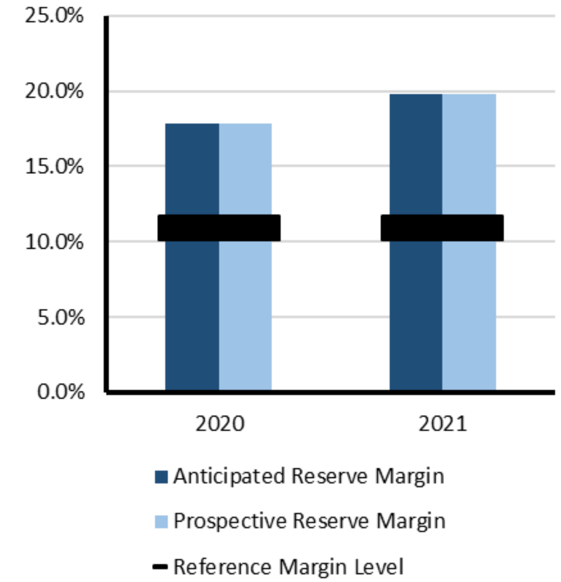
Highlights

- SaskPower experiences high load in summer as a result of hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro with inputs from Basin Electric (North Dakota) and prepares operating guidelines for any identified issues.
- Based on a SaskPower probability-based assessment, a low-likelihood scenario (1.8%) of capacity forced outages totaling 450 MW or greater that coincides with peak loads poses some risk of energy emergencies and unserved load. In the case of extreme hot weather 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. Risk is higher at the end of August to early October when larger amounts of generation maintenance is planned.

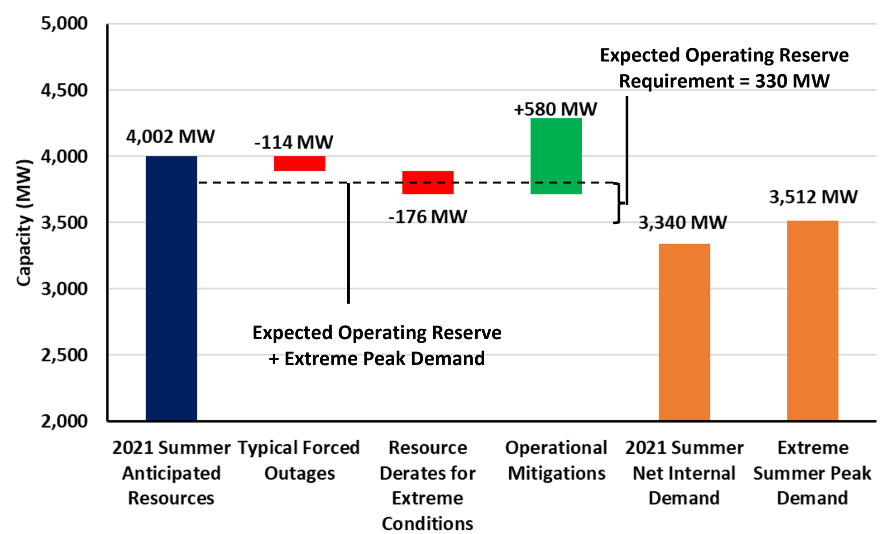
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).

On-Peak Reserve Margins



Risk-Period Scenario

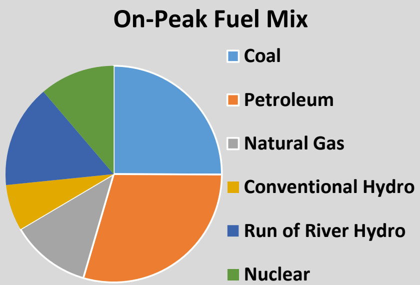


Scenario Description

- **Risk Period:** Periods of peak demand, afternoon (Risk is higher at the end of August to early October when more generation planned maintenance occurs.)
- **Demand Scenarios:** Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads
- **Maintenance Outages:** Estimated based on averages from June-September 2020
- **Forced Outages:** Estimated using SaskPower forced outage model
- **Extreme Derates:** Estimated derate on natural gas units under extreme warm weather (>35 ˚C) based on historic performance and manufacturer data
- **Operational Mitigation:** Based on operational/emergency procedures

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.

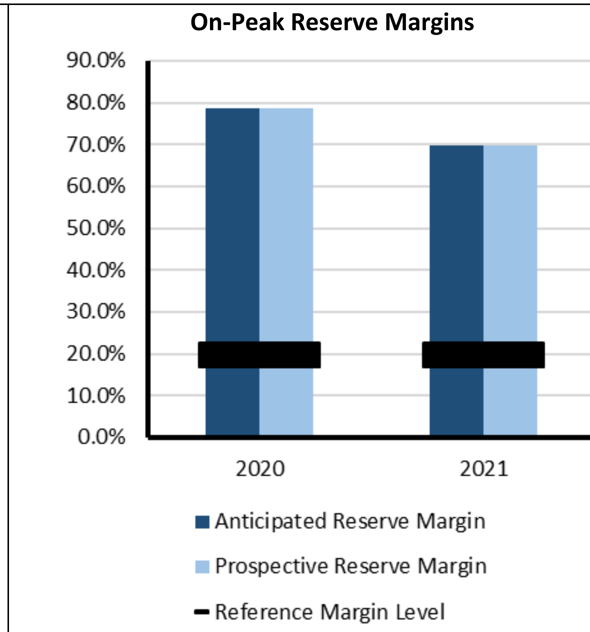


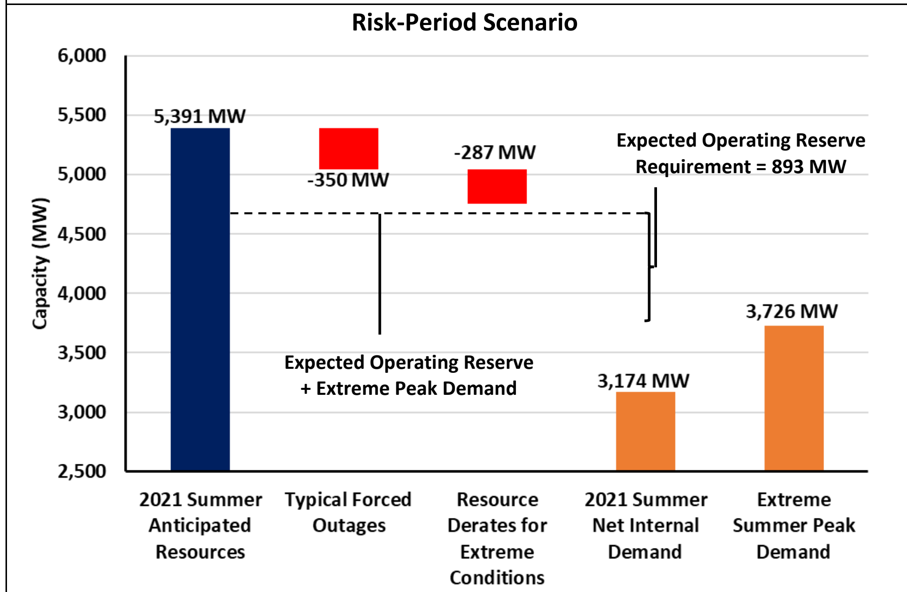
Highlights

- 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 declared firm capacity is expected to be operational for the summer.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions.
- The effects of the COVID-19 pandemic on load patterns, energy usage, and peak demands will continue to be evaluated during the pandemic.
- The Maritimes are evaluating contingency plans for transmission, distribution and generation planned work, planned maintenance, and forced outages to proceed conservatively while mitigating short term and longer term reliability risks.
- Based on an NPCC probabilistic assessment, the Maritimes assessment area is estimated to require a limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled.

Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.





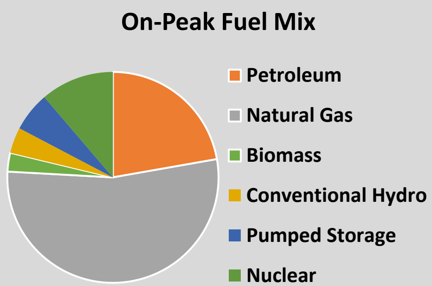
Scenario Description

- **Risk Period:** Periods of peak demand
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 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.

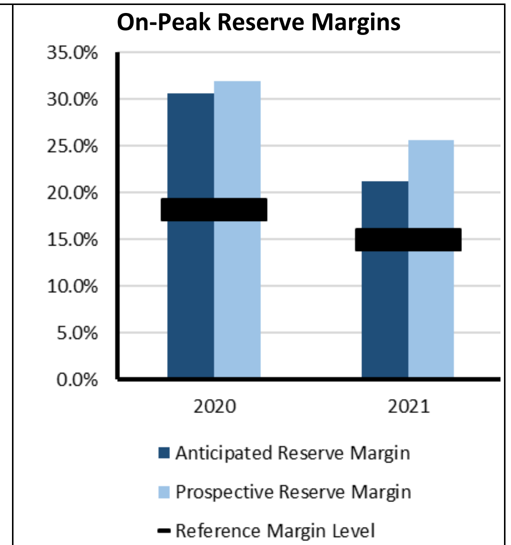


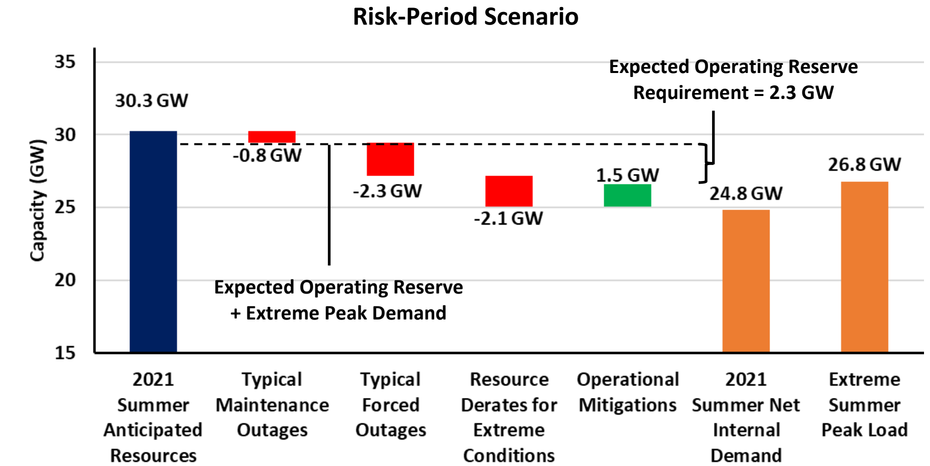
Highlights

- ISO New England (ISO-NE) expects to have sufficient resources to meet the area summer peak demand forecast. Peak summer demand is forecast to be 24,810 MW occurring the week of August 8 with a projected net margin of 1,910 MW (7.6%). The summer demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic systems, and distributed generation.
- ISO-NE is producing a weekly analysis of the impact the response to COVID-19 is having on New England system demand, posted on its external website every Tuesday.[17] ISO-NE will adjust forecasts based on trends.
- Based on an NPCC probabilistic assessment with scenarios, the New England assessment area is expected to require limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled except the severe low-likelihood case. The two highest peak load levels for this severe case resulted in LOLE of 0.3 days, with an associated LOLH of 1.3 hours, and an associated EUE of 868 MWh. This scenario is based exclusively on the two highest load levels representing an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurrence. Additional constraints include 10% reduction in NPCC resources and PJM reductions.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption.)





Scenario Description

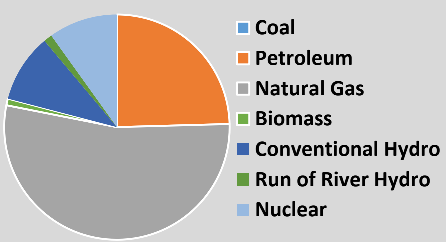
- **Risk Period:** Period of greatest risk coincides with peak demand (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Outages:** Based on weekly averages
- **Extreme Derates:** Represent a 90/10 case based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply
- **Operational Mitigation:** Based on ISO-NE operating procedures

[17] https://www.iso-ne.com/markets-operations/system-forecast-status/estimated-impacts-of-covid-19-on-demand

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 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 20.7%."

On-Peak Fuel Mix



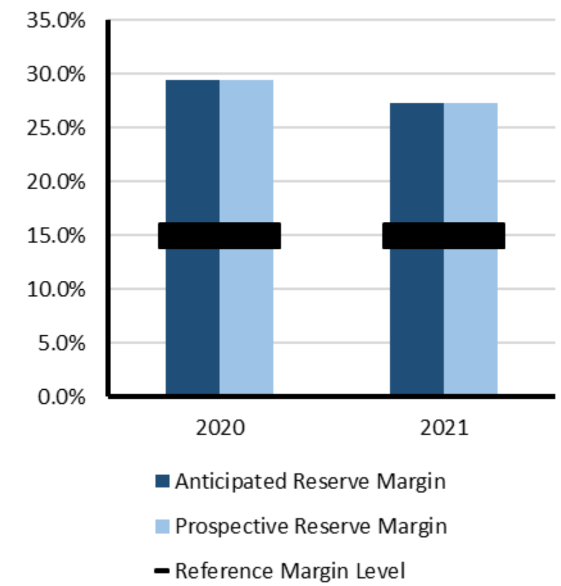
Highlights

- The NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- High capacity factors on certain New York City peaking units could result in possible violations of their daily NOx emission limits if they were to fully respond to the NYISO dispatch signals; this could occur during long duration hot weather events or following the loss of significant generation or transmission assets. Protocols with state agencies provide for reliable operation during emergencies.
- Based on an NPCC probabilistic assessment with scenarios, the New York assessment area is expected to require limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. New York's LOLE risk is correlated to simultaneous high loads occurring in PJM, Ontario, and MISO, which limits the availability of external support. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled except for the low-likelihood severe case that assumes simultaneous stressed system conditions for NPCC and the modeled external systems. The two highest peak load levels for this severe case resulted in an estimated LOLE of one occurrence in July, with an associated LOLH of four hours and an EUE of 3,020 MWh risk. The highest peak load level results were based exclusively on only the two highest load levels (representing on average 10–15% increase in peak loads over the 50/50 forecast) having a combined 7% chance of occurring. Additional constraints include 10% reduction in NPCC resources and PJM reductions.

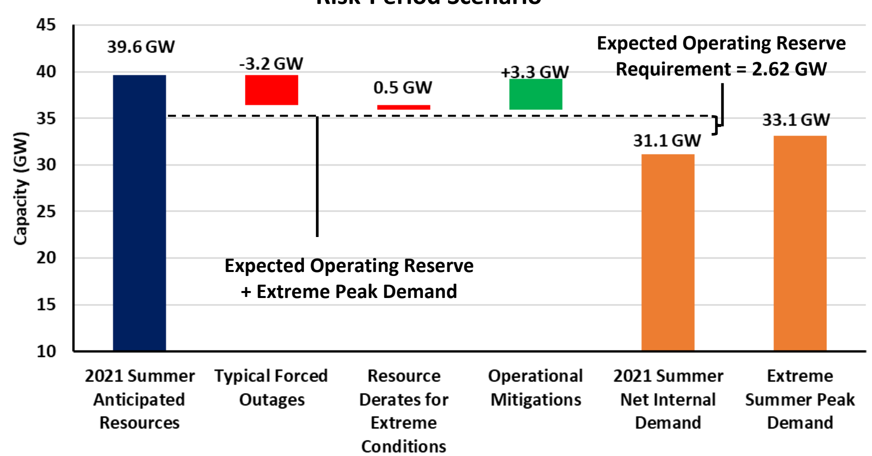
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



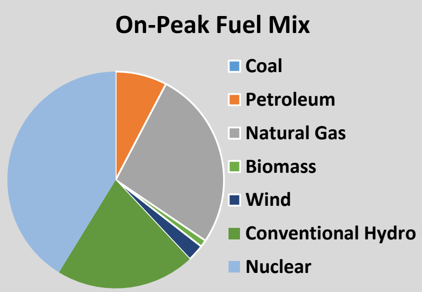
Scenario Description

- **Risk Period:** Periods of peak demand
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast with demand response adjustments
- **Forced Outages:** Based on historical 5-year averages
- **Extreme Derates:** Capacity derate for thermal resources for extreme conditions
- **Operational Mitigation:** 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.

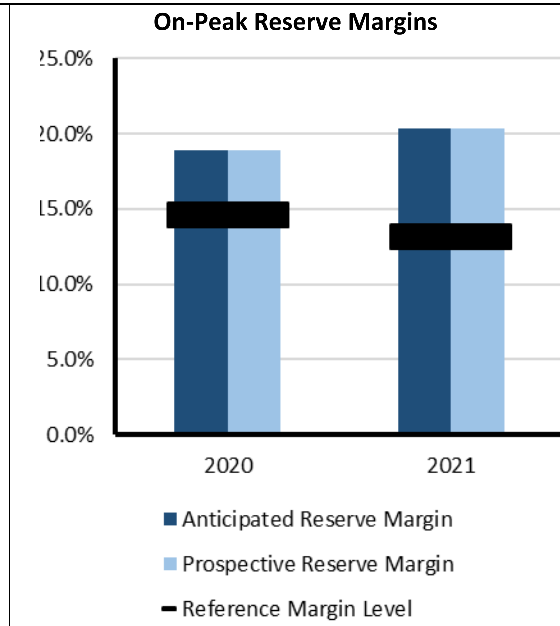


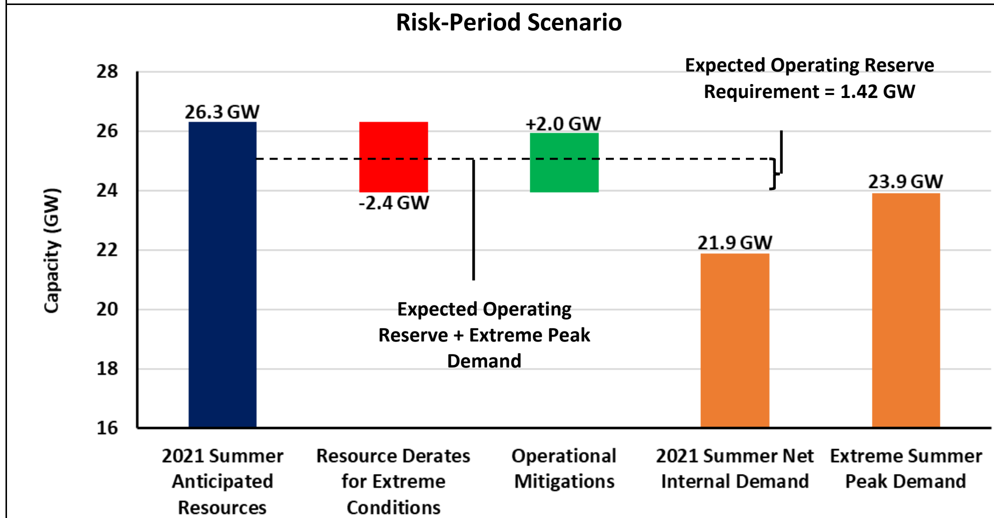
Highlights

- Ontario expects to have sufficient generation resources available to meet its needs throughout the summer, and its transmission system is expected to continue to reliably supply province-wide demand
- In December 2020, the IESO ran its first capacity auction, clearing 992.1 MW of capacity for the 2021 summer period. The capacity auction will be an important tool for meeting Ontario's future reliability needs.
- The ongoing transmission outage at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. The issue is being jointly managed by entities involved.
- Based on an NPCC probabilistic assessment, the Ontario assessment area is estimated to require a limited use of their operating procedures designed to mitigate resource shortages during Summer 2021. Ontario's LOLE risk is correlated to the availability of their external imports at the time of Ontario's peak load. Negligible amounts of LOLE, LOLH, and EUE were estimated over the summer period for all the scenarios modeled except the low-likelihood severe case and highest peak load levels (which resulted in an LOLE of 0.4 days with an associated LOLH of 1.2 hours and an associated EUE of 1,042 MWh risk in July). The highest peak load level results were based exclusively on only the two highest load levels of the seven modeled, having a combined 7% chance of occurring in this already low-likelihood case (with about a 10% reduction in NPCC resources and PJM reductions).

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).





Scenario Description

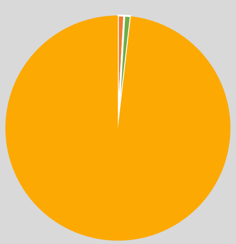
- **Risk Period:** Period of greatest risk coincides with peak demand (afternoon)
- **Demand Scenarios:** Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand from 31 years of demand history
- **Forced Outages:** Estimated using market forced outage model
- **Extreme Derates:** Hydro derates are based on 2012 (dry-year) conditions. Thermal derates are estimated using an extreme temperature from 31 years of historical data.
- **Operational Mitigation:** 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 NERC 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



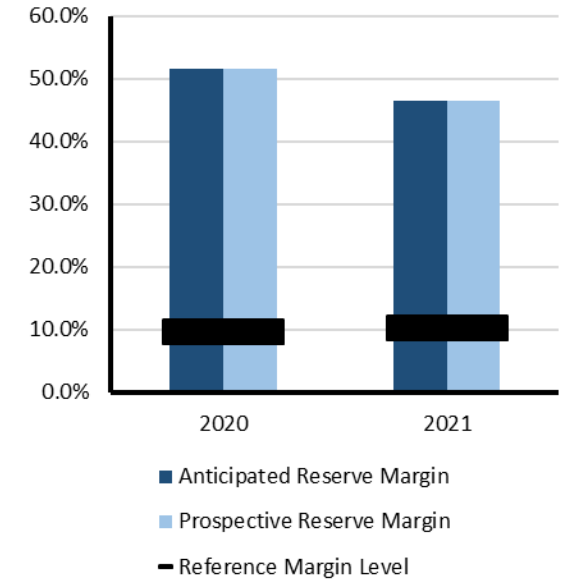
Highlights

- No issues are anticipated for the summer since the Québec system is winter peaking.
- Based on an NPCC probabilistic assessment, the Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2021. The Québec area is winter peaking and has a large reserve margin for the summer period; as a result, Québec did not demonstrate any measurable amounts of LOLE, LOLH, or EUE risk over the summer period for all the scenarios modeled.

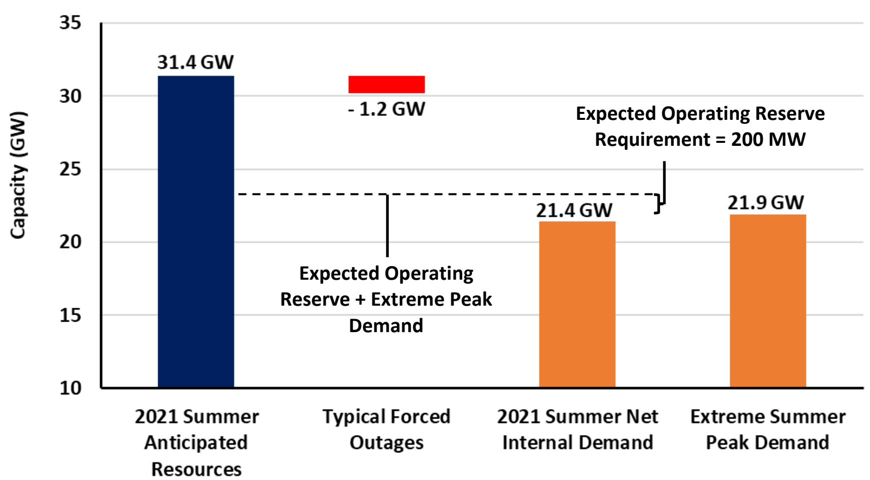
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

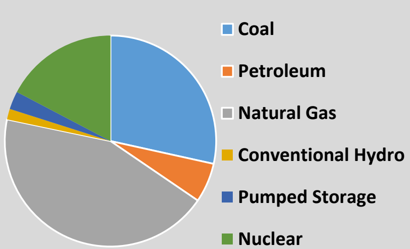
- **Risk Period:** Period of peak demand (afternoons)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Extreme Derates:** Rare scenario of 1,200 MW in unplanned outages

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 people and covers 369,089 square miles.

PJM is a BA, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

On-Peak Fuel Mix



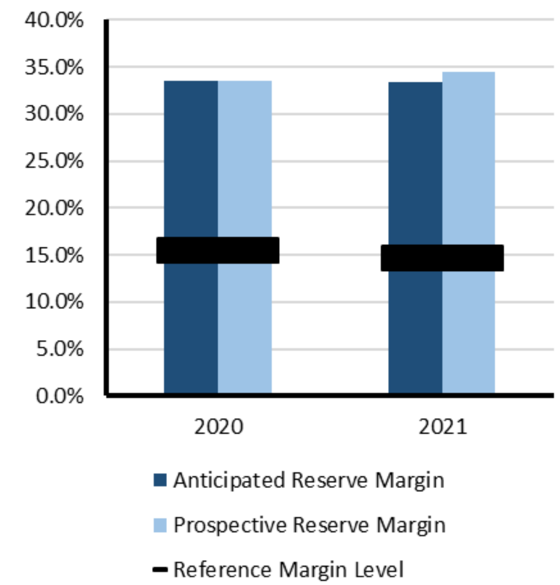
Highlights

- PJM expects no resource problems over the entire 2021 summer peak season. Installed capacity is almost double the Reference Margin Level and there are currently no known deliverability restrictions.
- Probabilistic studies performed by PJM indicate that there is low risk of resource shortfall for summer. The analysis included a range of load, generation, and outage scenarios.
- PJM's Reference Margin Level decreased from 15.1% to 14.9% due to lower average expected forced outage rates in the 2020 PJM capacity model compared to prior years.

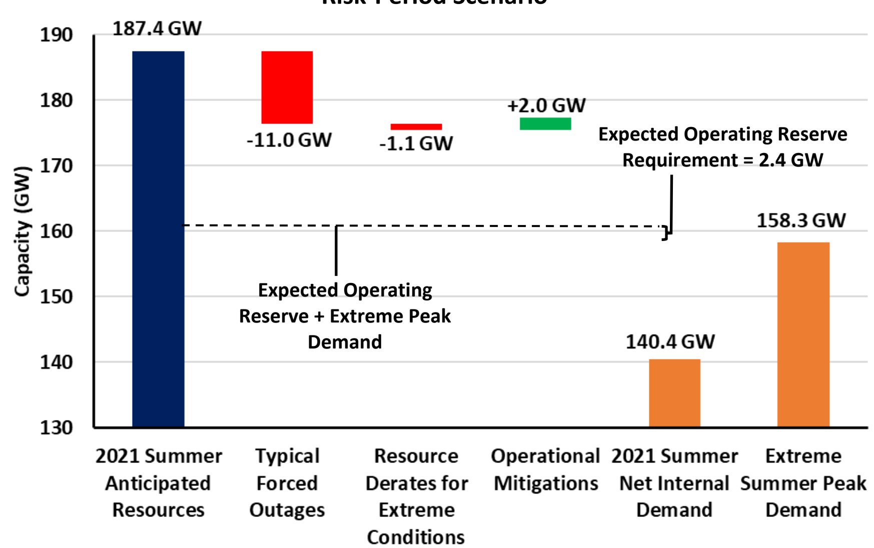
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

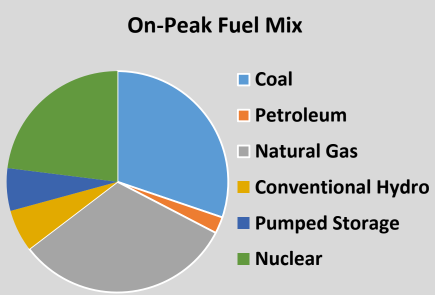
- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Outages:** Based on historical data and trending
- **Extreme Derates:** Derate accounts for reduced thermal capacity contributions due to performance in extreme conditions
- **Operational Mitigation:** A total of 2 GW obtained through emergency requests for behind-the-meter generation dispatch

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 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

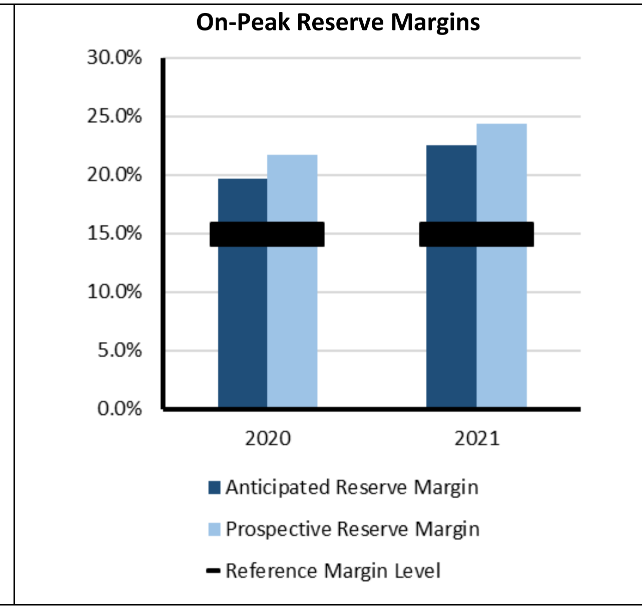


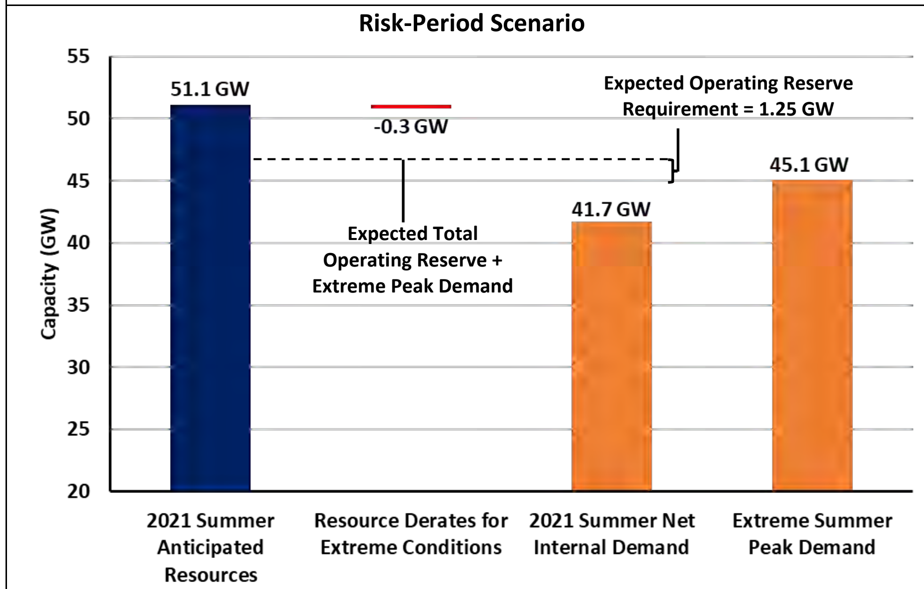
Highlights

- Entities in SERC-East have not identified any potential reliability issues for the upcoming season. The entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain reliability to the system. Entities reported that coal inventory is in the upper allowed range to maintain reliability.
- Entities in the SERC RE continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy as well as with transfer capability.
- Entities in SERC-East are not anticipating operational challenges for the upcoming summer season.
- Probabilistic analysis performed for SERC-East shows almost no risk for resource shortfall for the summer. SERC-East has a small amount of EUE in August but a negligible amount at other times (EUE < 0.4 MWh).

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **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:** Account for reduced thermal capacity contributions due to performance in extreme conditions

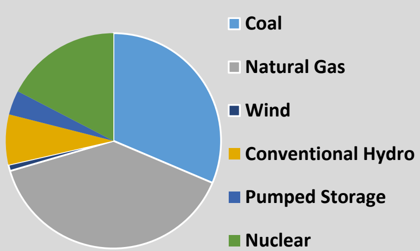
SERC-Central

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

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 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



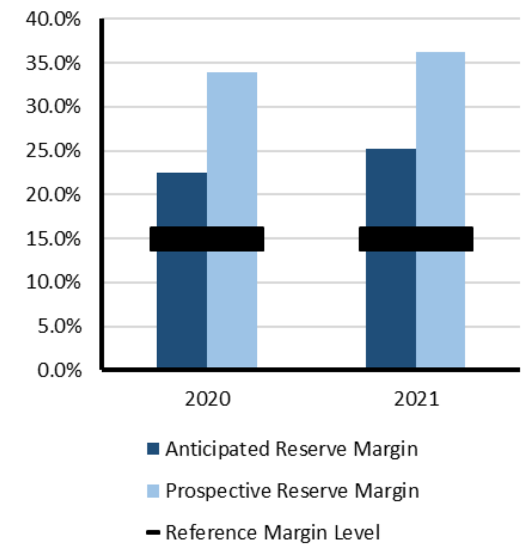
Highlights

- Entities in SERC-Central have not identified any potential reliability issues for the upcoming season. Entities have noted that planned outages are on schedule to be completed prior to the summer season and not anticipated to result in potential reliability issues.
- Entities in the SERC RE continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Central shows low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Central.

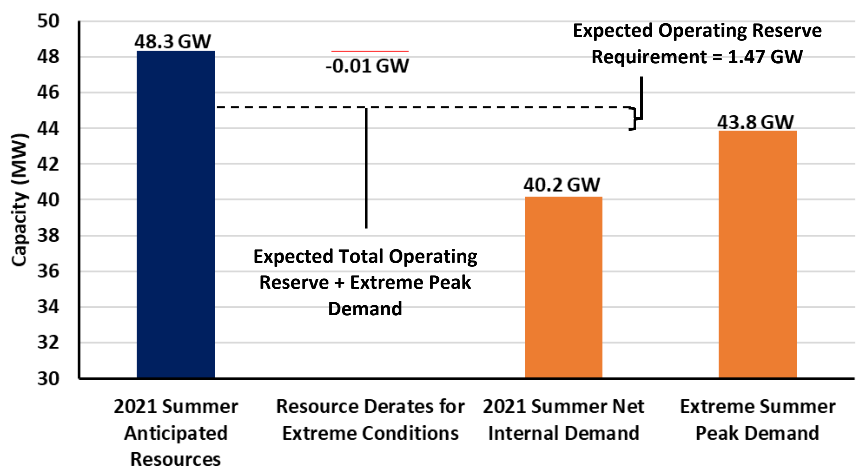
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description

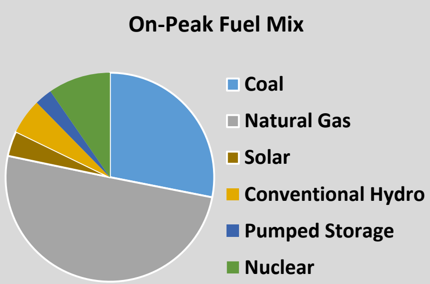
- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Weighted average forced outage rates on-peak are factored into the anticipated resources calculation
- **Extreme Derates:** Account 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 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

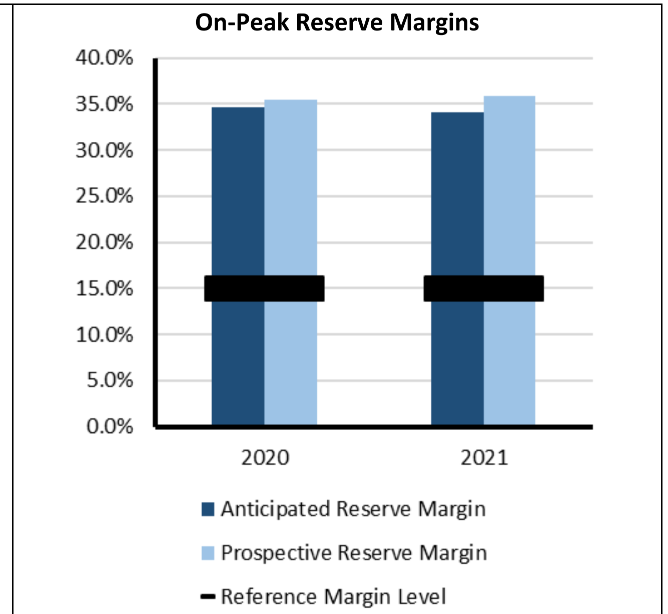


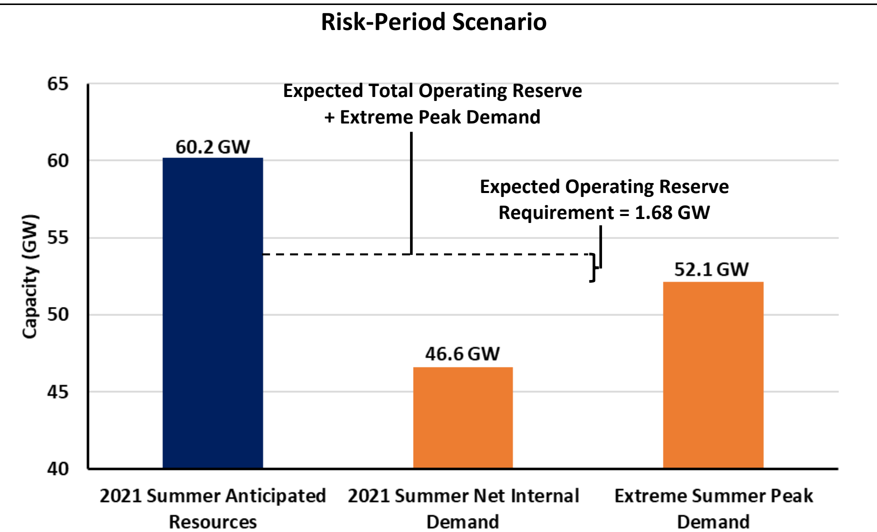
Highlights

- Entities in SERC Southeast have not identified any emerging reliability issues for the upcoming season that will impact resource adequacy. The available system capacity for the upcoming season meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm gas contracts, and power purchases.
- Entities in the SERC area continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Southeast shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Southeast throughout the summer.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description

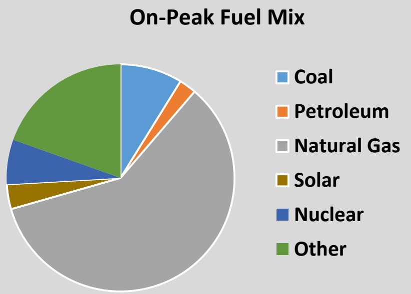
- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages and Extreme Derates:** All outages and derates are factored into the anticipated resources calculation

SERC-Florida Peninsula

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

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 BA, 28 Planning Authorities, and 6 Reliability Coordinators.

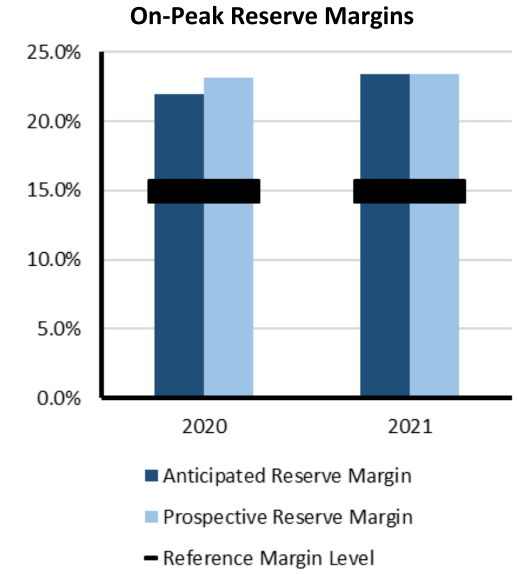


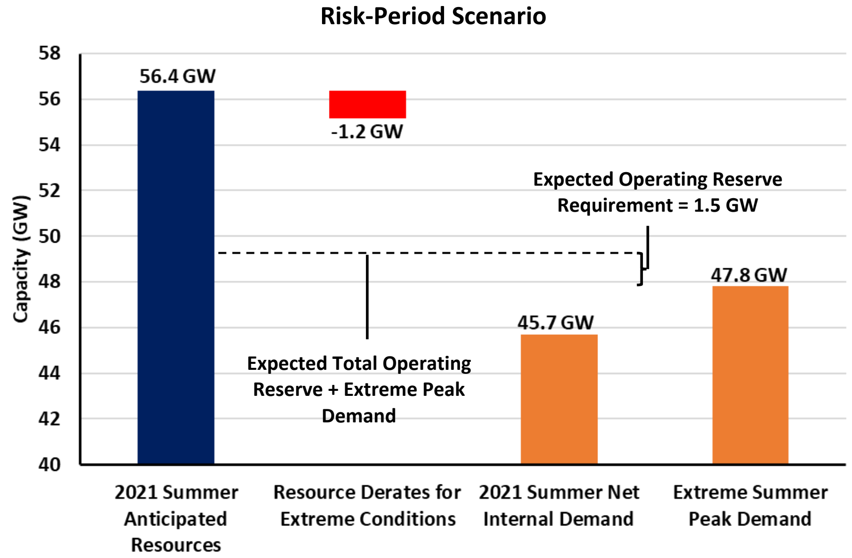
Highlights

- Entities in SERC-Florida Peninsula have not identified any emerging reliability issues or operational concerns for the upcoming summer. Entities in the SERC Region continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities within the Florida Peninsula area have reported no operational challenges for the upcoming summer season based on current expected system conditions, the BES within the Florida Peninsula is expected to perform reliably for the anticipated 2021 summer season.
- Probabilistic analysis performed for SERC-Florida Peninsula shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices for SERC-Florida Peninsula are spread across the summer months but are relatively low (LOLH < 0.03 and EUE < 18 MWH).

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





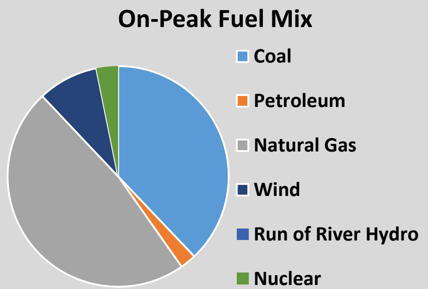
Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **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:** Account 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.

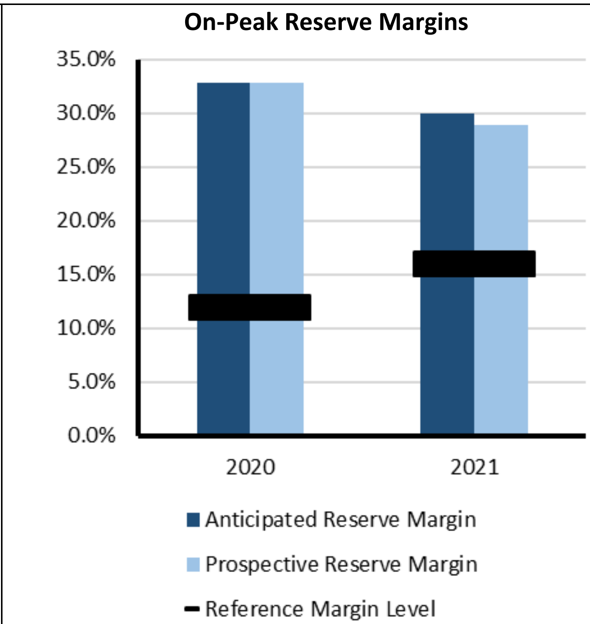


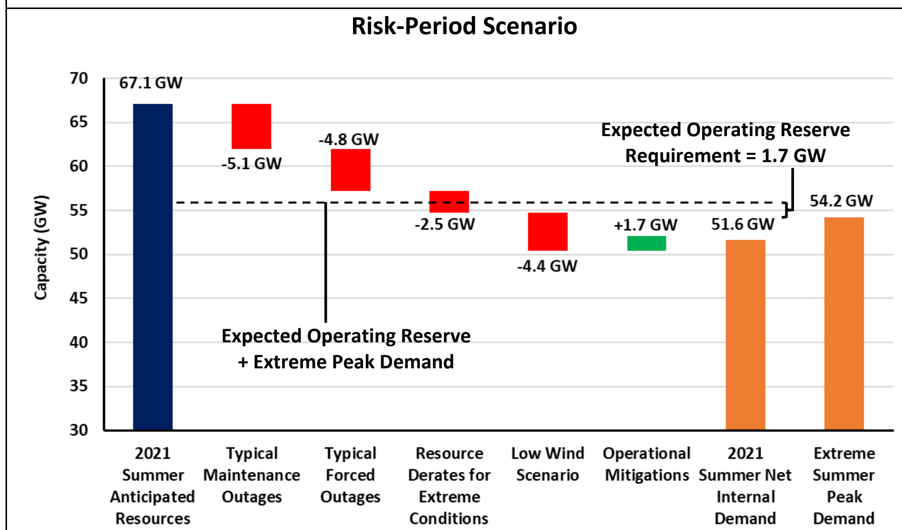
Highlights

- At this time, SPP does not anticipate any emerging reliability issues impacting the area for the 2021 summer season.
- Wind generation occupies a greater share of the SPP resource mix, requiring increased attention to weather-dependent forecasts. The SPP Uncertainty Response Team uses historical data to predict and develop mitigation plans for load forecast errors up to seven days in advance. Potential errors are predicted based on the levels of expected load, wind, and traditional resource outage in forecast. Mitigation may be obtained by scheduling longer-lead resources, controlling planned outages, and communicating with owners and operators.
- Using the current operational processes and procedures, SPP will continue to assess the needs for the 2021 summer season and will adjust as needed to ensure that real time reliability is maintained throughout the summer time frame.
- Probabilistic studies performed by SPP indicate for the 2021 summer season indicate that the current Planning Reserve Margin is sufficient for the 2021 summer season.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).





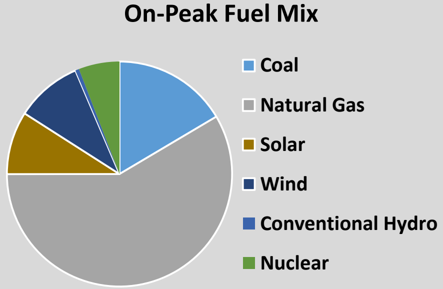
Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Maintenance Outages:** Based on historical summer average for the past three years
- **Forced Outages:** Based on historical summer average for the past three years
- **Extreme Thermal Derates:** Derate accounts for reduced capacity contributions due to performance in extreme conditions
- **Low-Wind Scenario:** Rare scenario with only 320 MW (of 26,800 MW installed capacity) contributing to meet demand
- **Operational Mitigation:** 1,700 MW based on operational/emergency procedures

Texas RE-ERCOT

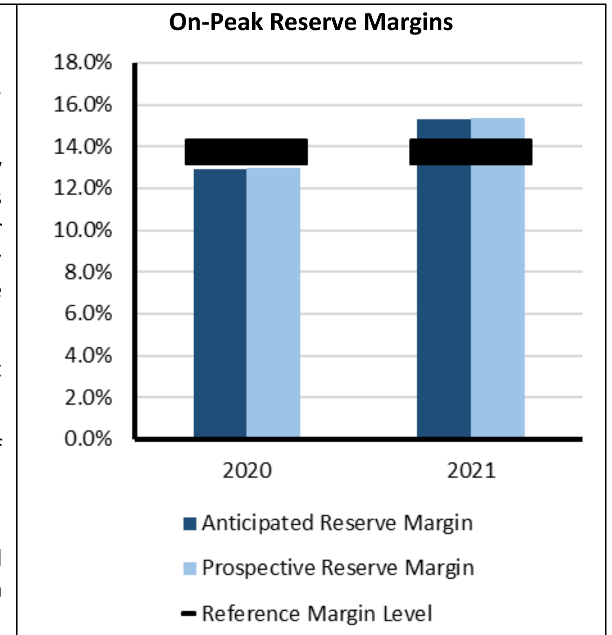
The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million 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.



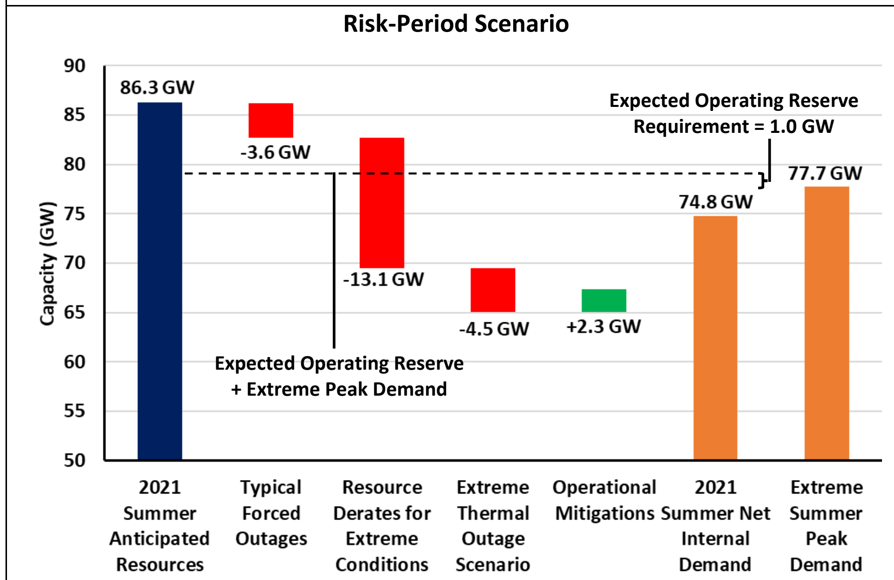
Highlights

- Summer probabilistic analysis performed by ERCOT indicates that the risk of unserved energy is low. Hour-ending 5:00 p.m. continues to be ERCOT's highest-risk hour for unserved energy with the likelihood of unserved energy less than 0.2%.
- Variable energy resources from wind and solar are critical to meeting peak electricity demand in ERCOT. Periods of low wind generation or higher-than expected thermal outages create a reliability risk during peak load hours. ERCOT appears to be in a weather cycle that may increase the risk of intensifying drought conditions and higher than normal summer temperatures. These weather factors could result in actual summer peak demand exceeding the forecast, which already anticipates record peak demand levels. Thermal outages may increase during severe and prolonged drought conditions due to cooling water supply and temperature issues.
- Given an Anticipated Reserve Margin of 15.3% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for summer system conditions.
- Delays or cancellations of planned transmission expansion projects in the western part of the Lower Rio Grande Valley, if they occur, may contribute to potential localized reliability concerns.



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).



Scenario Description

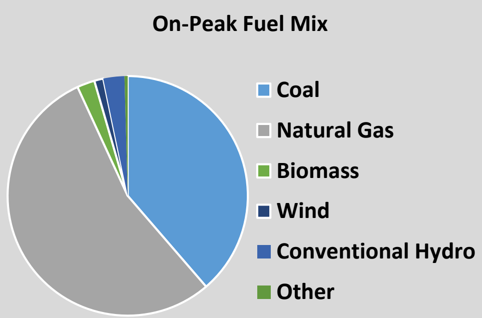
- **Risk Period:** Highest risk for unserved energy at peak demand hour, late afternoon (Risk can extend for 1–2 hours after peak as solar PV output diminishes. Periods of low-wind, which usually occur 1–2 hours before peak demand, can also result in extended shortfall risk.
- **Demand Scenarios:** Net internal demand (50/50) and extreme demand based on 2011 historic summer peak demand (approximates 90/10 demand forecast)
- **Forced Outages:** Based on historical average of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m., for the last three summer seasons (2018–2020)
- **Extreme Derates:** Additional derates of 2,605 MW (thermal), 6,576 MW (wind), and 2,953 MW (PV) for extreme conditions (i.e., based on the 95th percentile of historical forced outages for June–September weekdays, hours ending 3:00–8:00 p.m., for the last three years.
- **Extreme Outage Scenario:** Additional increments of thermal and hydro forced outages equating to highest hourly forced outages from 2011–2021 **(**When combined with extreme derates shown in the Risk-Period Scenario, it represents a very rare resource condition.)
- **Operational Mitigation:** Additional resources, primarily from load resources, but also switchable generation, additional imports, and voltage reduction)

WECC-AB

WECC-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 38 BA, 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 people, it is geographically the largest and most diverse of the NERC 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, and all or portions of the 14 Western United States in between.

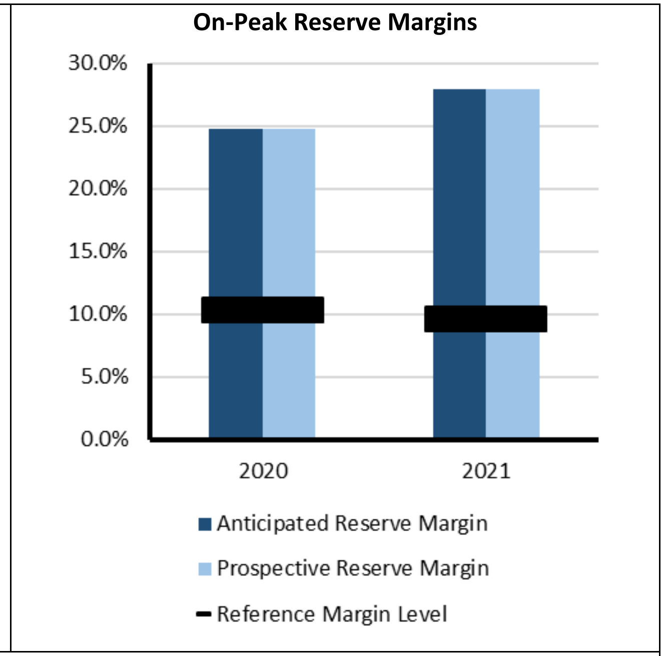


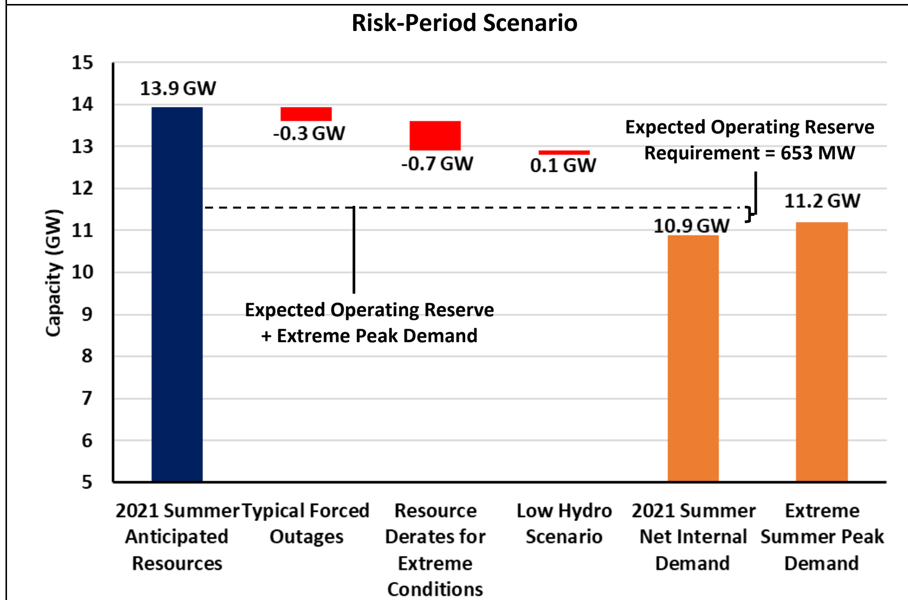
Highlights

- WECC-Alberta is a winter peaking province. Sufficient resources are anticipated to meet summer demand.
- Based on a WECC probabilistic assessment, the WECC-AB assessment area had negligible LOLH and EUE.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description

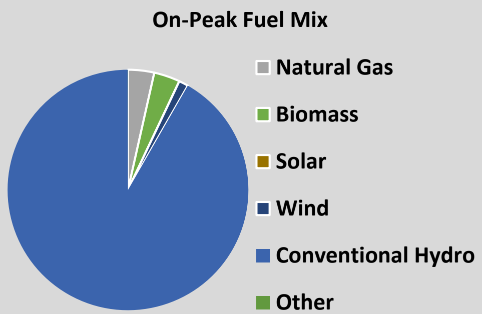
- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate using 90/10 scenario

WECC-BC

WECC-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 38 BA, 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 people, it is geographically the largest and most diverse of the NERC 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, and all or portions of the 14 Western United States in between.

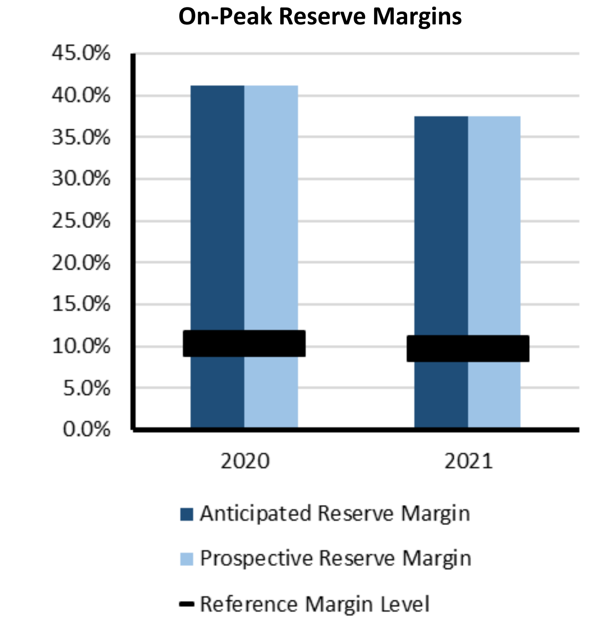


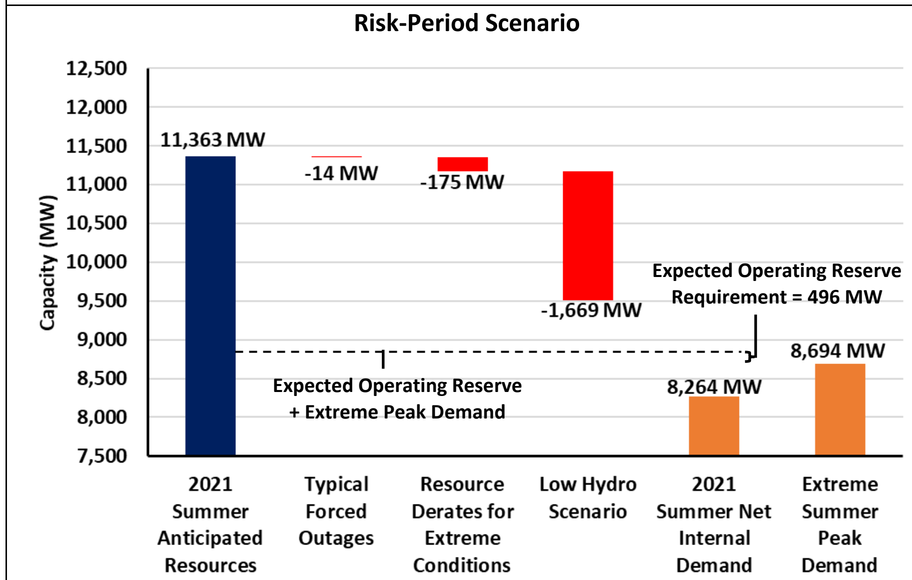
Highlights

- WECC-British Columbia is a winter peaking province. Sufficient resources are anticipated to meet summer demand.
- Based on a WECC probabilistic assessment, the WECC-AB assessment area had negligible LOLH and EUE.

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.





Scenario Description

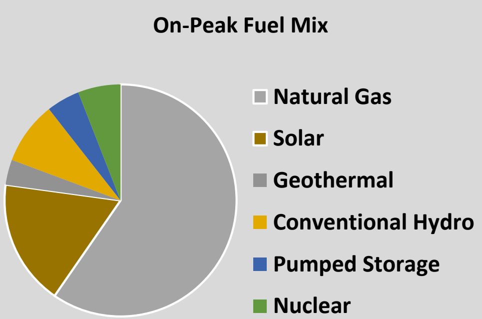
- **Risk Period:** Highest risk for unserved energy at peak demand hour (afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate using 90/10 scenario

WECC-CAMX

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

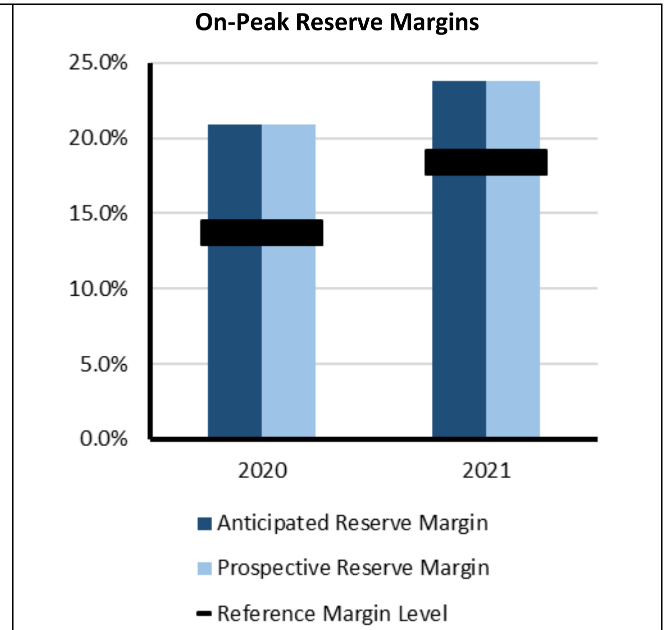
WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members, which include 38 BA, represent a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million people, it is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



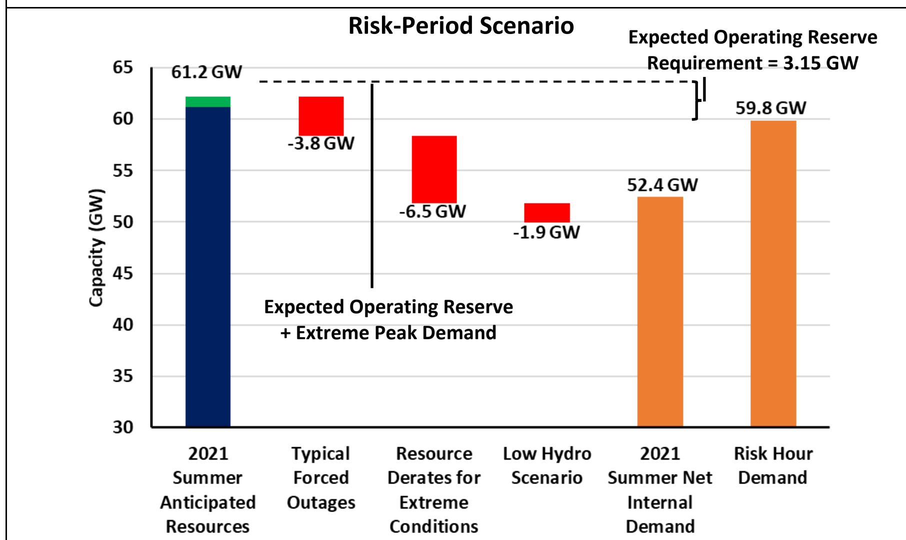
Highlights

- Anticipated resources, which include new capacity in development as well as imports, are expected to be sufficient to meet summer peak demand. However, supply shortfalls from unanticipated low variable generation output, limited imports, or thermal generation outages could lead to energy emergencies. Extreme demand, as seen in 2020, could also lead to emergencies.
- WECC-CAMX has planned resource additions of 1,300 MW over the summer, including 825 MW of new battery storage that are in development. Owners and operators must keep focus on project timelines and implementation milestones to meet anticipated resource levels and help reduce resource adequacy risks in late-summer.
- The Western Interconnection is at risk of experiencing operating challenges from wildfires. Transmission lines may be removed from service in areas with active wildfires or heightened wildfire risk. These transmission outages can impose BPS operational constraints resulting in loss of load events.
- Based on a WECC probabilistic assessment, the California portion of the assessment area has an LOLH of 0.20 hours and an EUE of 10,185 MWh. The Mexico portion has negligible LOLH and EUE.



Risk Scenario Summary

Expected resources (including summer additions) meet operating reserve requirements under normal demand scenarios. Above-normal peak load would cause area resource shortages during periods of peak demand and extend into evenings as solar PV output diminishes while demand remains high. High thermal resource outages or reduced availability of imports associated with extreme or wide-area heat events are likely to result in firm load-shed.



Scenario Description

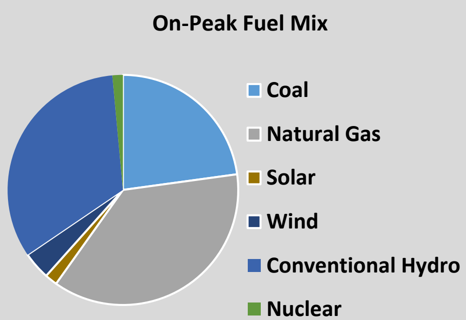
- **Risk Period:** Period of greatest risk typically within two hours following afternoon peak demand as solar PV output diminishes
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Estimated using market forced outage model
- **Extreme Derates:** Derate on natural gas units based on historic data and manufacturer data for temperature performance and outages

WECC-NWPP & RMRG

WECC Northwest Power Pool and Rocky Mountain Reserve Sharing Group is an assessment area in the WECC RE. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and 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 38 BA, 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 people, it is geographically the largest and most diverse of the NERC 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, and all or portions of the 14 Western United States in between.

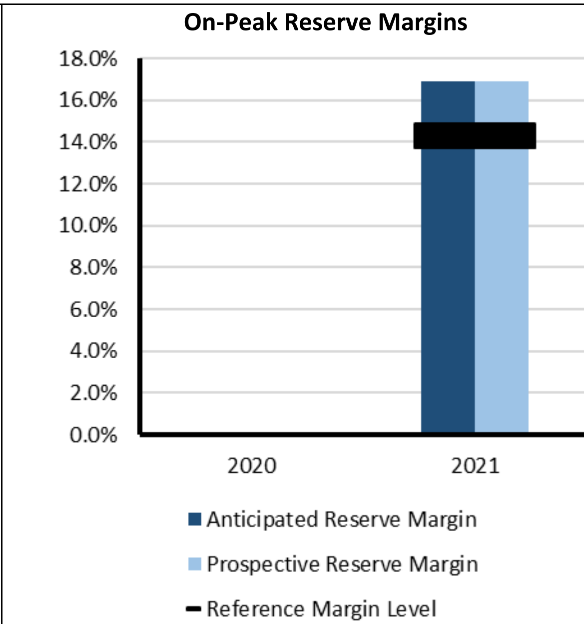


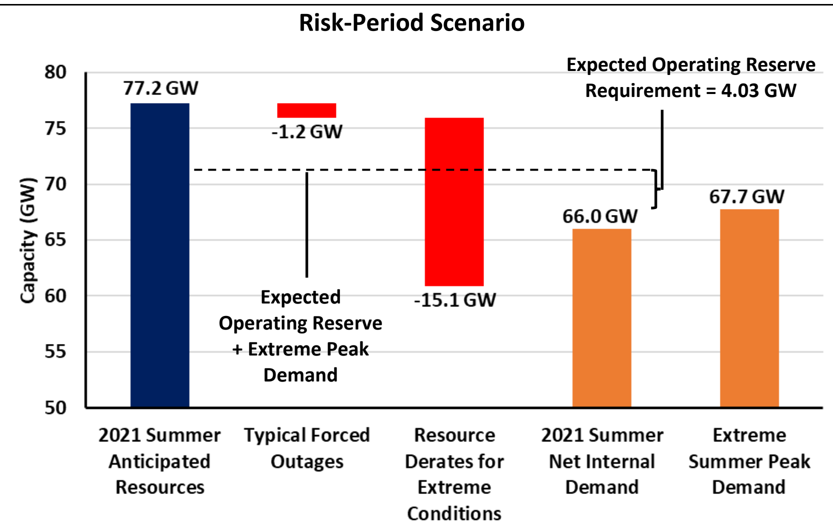
Highlights

- The anticipated reserve margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season
- WECC merged the NWPP and RMRG assessment areas in late 2020, so an Anticipated Reserve Margin or a Reference Margin Level was not produced for the 2020 assessment year for comparison. However, it is estimated that anticipated resources have declined by 4% since 2020 while demand is not significantly changed in the merged area for the upcoming summer (see **Demand and Resource Tables**).
- Localized short-term operational issues may occur due to wildfires. Due to the widely dispersed nature of the transmission system, outages due to wildfires are generally not widespread.
- Based on a WECC probabilistic assessment, the WECC-NWPP assessment area had an LOLH of 0.06 hour and a EUE of 3,442 MWh.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).





Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate using 90/10 scenario

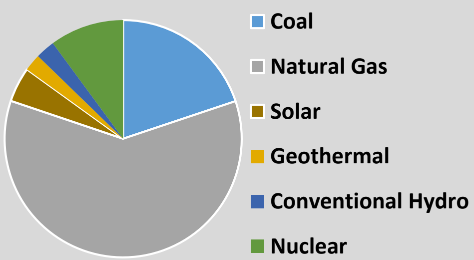
WECC-SRSG

WECC Southwest Reserve Sharing Group is an assessment area in the WECC RE. It includes Arizona and 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 38 BA, 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 people, it is geographically the largest and most diverse of the NERC 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, and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix

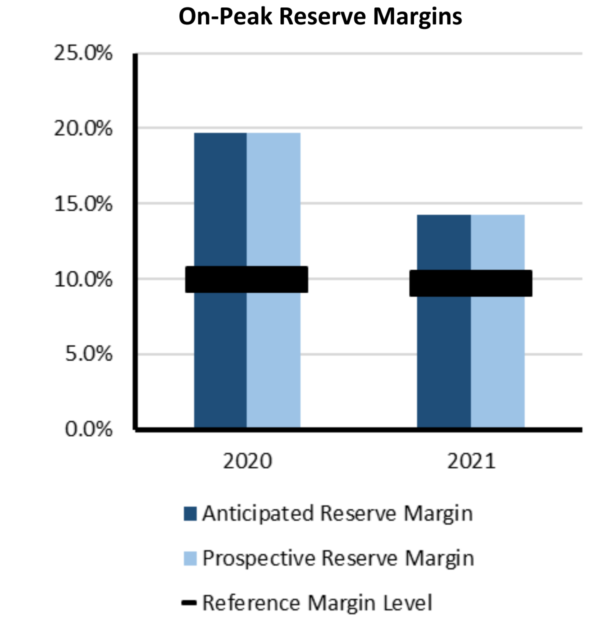


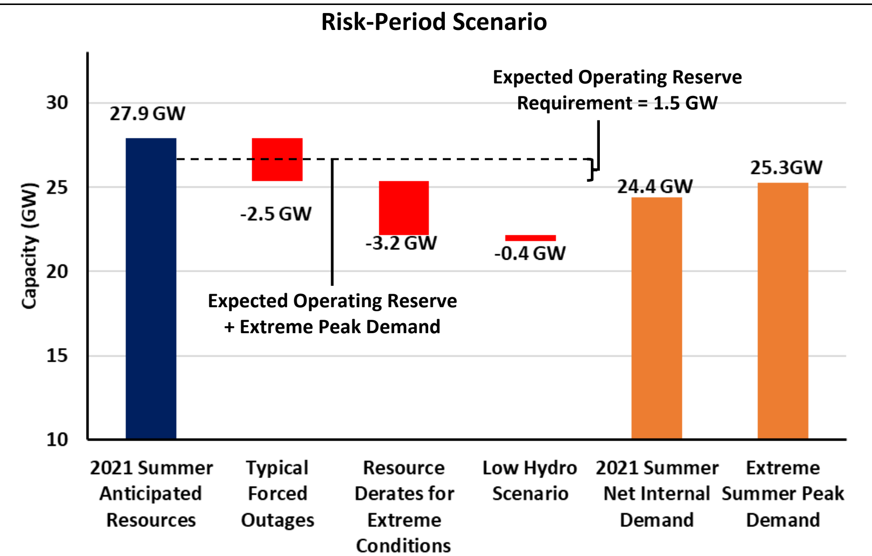
Highlights

- The Anticipated Reserve Margins for WECC, its subregions, and all zones within are expected to exceed their respective NERC Reference Margin Levels for the upcoming season.
- For the upcoming summer season, California ISO is procuring resources to improve reliability risks.
- Localized short-term operational issues may occur due to wildfires. Due to the widely dispersed nature of the transmission system, outages due to wildfires are generally not widespread.
- Based on a WECC probabilistic assessment, the WECC-SRSG assessment area had negligible LOLH and EUE.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, and short-term load interruption).





Scenario Description

- **Risk Period:** Highest risk for unserved energy at peak demand hour (late afternoon)
- **Demand Scenarios:** Net internal demand (50/50) and 90/10 demand forecast
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Derate 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 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 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[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. **Table 2** below shows the wind and solar generation resources in each assessment area and describes how capacity contributions values are determined.
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 summer 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.
Reserve Margin Descriptions

[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.

	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 summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, 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 low-probability, extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer 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.

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below.

MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	124,866	122,398	-2.0%
Demand Response: Available	6,172	6,038	-2.2%
Net Internal Demand	118,694	116,360	-2.0%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	140,636	138,464	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,795	2,979	6.6%
Anticipated Resources	143,430	141,443	-1.4%
Existing-Other Capacity	290	633	118.1%
Prospective Resources	143,720	146,586	2.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	20.8%	21.6%	0.8
Prospective Reserve Margin	21.1%	26.0%	4.9
Reference Margin Level	18.0%	18.3%	0.3

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	3,480	3,400	-2.3%
Demand Response: Available	60	60	0.0%
Net Internal Demand	3,420	3,340	-2.3%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	3,904	3,863	-1.1%
Tier 1 Planned Capacity	0	14	-
Net Firm Capacity Transfers	125	125	0.0%
Anticipated Resources	4,029	4,002	-0.7%
Existing-Other Capacity	0	0	-
Prospective Resources	4,029	4,002	-0.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	17.8%	19.8%	2.0
Prospective Reserve Margin	17.8%	19.8%	2.0
Reference Margin Level	11.0%	11.0%	0.0

MRO-Manitoba Hydro Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	3,272	2,965	-9.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,272	2,965	-9.4%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	5,239	5,173	-1.3%
Tier 1 Planned Capacity	0	186	-
Net Firm Capacity Transfers	-1,526	-1,596	4.6%
Anticipated Resources	3,713	3,763	1.4%
Existing-Other Capacity	125	37	-70.3%
Prospective Resources	3,838	3,800	-1.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	13.5%	26.9%	13.4
Prospective Reserve Margin	17.3%	28.2%	10.9
Reference Margin Level	12.0%	12.0%	0.0

NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2020 SRA	2021 SRA	2020 vs. 2021 SRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Total Internal Demand (50/50)	3,370	3,479	3.2%
Demand Response: Available	369	305	-17.3%
Net Internal Demand	3,001	3,174	5.8%
Resource Projections	Megawatts (MW)	Megawatts (MW)	Net Change (%)
Existing-Certain Capacity	5,312	5,448	2.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-53	-57	7.5%
Anticipated Resources	5,259	5,391	2.5%
Existing-Other Capacity	0	0	-
Prospective Resources	5,259	5,391	2.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	75.2%	69.8%	-5.4
Prospective Reserve Margin	75.2%	69.8%	-5.4
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	25,158	25,244	0.3%
Demand Response: Available	443	434	-2.0%
Net Internal Demand	24,715	24,810	0.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	30,791	29,065	-5.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,510	1,208	-20.0%
Anticipated Resources	32,301	30,273	-6.3%
Existing-Other Capacity	324	1,115	244.1%
Prospective Resources	32,625	31,388	-3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.7%	22.0%	-8.7
Prospective Reserve Margin	32.0%	26.5%	-5.5
Reference Margin Level	18.3%	15.0%	-3.3

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	22,195	22,500	1.4%
Demand Response: Available	518	621	20.0%
Net Internal Demand	21,677	21,879	0.9%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	25,719	26,217	1.9%
Tier 1 Planned Capacity	49	22	-55.6%
Net Firm Capacity Transfers	0	80	-
Anticipated Resources	25,768	26,319	2.1%
Existing-Other Capacity	0	0	-
Prospective Resources	25,768	26,319	2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.9%	20.3%	1.4
Prospective Reserve Margin	18.9%	20.3%	1.4
Reference Margin Level	14.6%	13.2%	-1.4

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	32,296	32,333	0.1%
Demand Response: Available	1,282	1,199	-6.5%
Net Internal Demand	31,014	31,134	0.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	38,475	37,805	-1.7%
Tier 1 Planned Capacity	101.2	0	-100.0%
Net Firm Capacity Transfers	1,562	1,816	16.3%
Anticipated Resources	40,138	39,621	-1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	40,138	39,621	-1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.4%	27.3%	-2.1
Prospective Reserve Margin	29.4%	27.3%	-2.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	21,635	21,436	-0.9%
Demand Response: Available	0	0	-
Net Internal Demand	21,635	21,436	-0.9%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	34,771	33,380	-4.0%
Tier 1 Planned Capacity	14.25	0	-100.0%
Net Firm Capacity Transfers	-1,963	-1,995	1.6%
Anticipated Resources	32,822	31,385	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	32,822	31,385	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	51.7%	46.4%	-5.3
Prospective Reserve Margin	51.7%	46.4%	-5.3
Reference Margin Level	9.8%	10.4%	0.6

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	148,092	149,224	0.8%
Demand Response: Available	8,929	8,779	-1.7%
Net Internal Demand	139,163	140,445	0.9%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	182,523	183,572	0.6%
Tier 1 Planned Capacity	1800	2,400	33.3%
Net Firm Capacity Transfers	1,412	1,460	3.4%
Anticipated Resources	185,735	187,431	0.9%
Existing-Other Capacity	0	0	-
Prospective Resources	185,735	188,891	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	33.5%	0.0
Prospective Reserve Margin	33.5%	34.5%	1.0
Reference Margin Level	15.5%	14.7%	-0.8

SERC-E Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	43,702	42,680	-2.3%
Demand Response: Available	947	970	2.4%
Net Internal Demand	42,755	41,710	-2.4%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	50,825	50,539	-0.6%
Tier 1 Planned Capacity	88	0	-100.0%
Net Firm Capacity Transfers	266	562	111.3%
Anticipated Resources	51,179	51,101	-0.2%
Existing-Other Capacity	851.5	766	-10.0%
Prospective Resources	52,030	51,867	-0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.7%	22.5%	2.8
Prospective Reserve Margin	21.7%	24.4%	2.7
Reference Margin Level	15.0%	15.0%	0.0

SERC-C Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	40,799	40,341	-1.1%
Demand Response: Available	1,970	1,744	-11.5%
Net Internal Demand	38,829	38,597	-0.6%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	48,368	47,987	-0.8%
Tier 1 Planned Capacity	0	154	-
Net Firm Capacity Transfers	-807	172	-121.3%
Anticipated Resources	47,561	48,314	1.6%
Existing-Other Capacity	4427	4,290	-3.1%
Prospective Resources	51,988	52,604	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.5%	25.2%	2.7
Prospective Reserve Margin	33.9%	36.3%	2.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-FP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	49,286	48,710	-1.2%
Demand Response: Available	2,906	3,030	4.3%
Net Internal Demand	46,380	45,680	-1.5%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	55,093	55,351	0.5%
Tier 1 Planned Capacity	333	0	-100.0%
Net Firm Capacity Transfers	1,146	1,007	-12.1%
Anticipated Resources	56,571	56,358	-0.4%
Existing-Other Capacity	529	0	-100.0%
Prospective Resources	57,100	56,358	-1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	23.4%	1.4
Prospective Reserve Margin	23.1%	23.4%	0.3
Reference Margin Level	15.0%	15.0%	0.0

SERC-SE Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	47,311	46,631	-1.4%
Demand Response: Available	2,145	1,671	-22.1%
Net Internal Demand	45,166	44,960	-0.5%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	61,495	61,263	-0.4%
Tier 1 Planned Capacity	316	142	-55.0%
Net Firm Capacity Transfers	-972	-1,115	14.7%
Anticipated Resources	60,839	60,290	-0.9%
Existing-Other Capacity	348	783	125.3%
Prospective Resources	61,186	61,073	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	34.7%	34.1%	-0.6
Prospective Reserve Margin	35.5%	35.8%	0.3
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	75,200	77,144	2.6%
Demand Response: Available	2,251	2,341	4.0%
Net Internal Demand	72,949	74,803	2.5%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	79,395	80,569	1.5%
Tier 1 Planned Capacity	2172	5,489	152.7%
Net Firm Capacity Transfers	817	210	-74.3%
Anticipated Resources	82,384	86,268	4.7%
Existing-Other Capacity	0	0	-
Prospective Resources	82,412	86,296	4.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.9%	15.3%	2.4
Prospective Reserve Margin	13.0%	15.4%	2.4
Reference Margin Level	13.75%	13.75%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	51,943	52,249	0.6%
Demand Response: Available	835	606	-27.4%
Net Internal Demand	51,108	51,643	1.0%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	69,100	66,600	-3.6%
Tier 1 Planned Capacity	0	300	-
Net Firm Capacity Transfers	-1,244	186	-115.0%
Anticipated Resources	67,856	67,086	-1.1%
Existing-Other Capacity	0	0	-
Prospective Resources	67,856	66,539	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.8%	29.9%	-2.9
Prospective Reserve Margin	32.8%	28.8%	-4.0
Reference Margin Level	12.0%	16.0%	4.0

WECC-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	11,500	10,886	-5.3%
Demand Response: Available	0	0	-
Net Internal Demand	11,500	10,886	-5.3%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	14,356	12,205	-15.0%
Tier 1 Planned Capacity	0	1,723	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	14,356	13,928	-3.0%
Existing-Other Capacity	0	0	-
Prospective Resources	14,356	13,928	-3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.8%	27.9%	3.1
Prospective Reserve Margin	24.8%	27.9%	3.1
Reference Margin Level	10.4%	9.7%	-0.7

WECC-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	8,278	8,264	-0.2%
Demand Response: Available	0	0	-
Net Internal Demand	8,278	8,264	-0.2%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	11,471	11,178	-2.6%
Tier 1 Planned Capacity	215	185	-13.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,686	11,363	-2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	11,686	11,363	-2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.2%	37.5%	-3.7
Prospective Reserve Margin	41.2%	37.5%	-3.7
Reference Margin Level	10.4%	9.7%	-0.7

WECC-CA / MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	53,236	55,409	4.1%
Demand Response: Available	910	922	1.2%
Net Internal Demand	52,326	54,487	4.1%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	63,186	63,396	0.3%
Tier 1 Planned Capacity	92	3,358	3555.6%
Net Firm Capacity Transfers	0	686	-
Anticipated Resources	63,278	67,440	6.6%
Existing-Other Capacity	0	0	-
Prospective Resources	63,278	67,440	6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	23.8%	2.9
Prospective Reserve Margin	20.9%	23.8%	2.9
Reference Margin Level	13.7%	18.4%	4.7

WECC-NWPP-US and RMRG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	66,532	67,117	0.9%
Demand Response: Available	868	1,087	25.2%
Net Internal Demand	65,664	66,030	0.6%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	78,839	70,069	-11.1%
Tier 1 Planned Capacity	870	1,002	15.2%
Net Firm Capacity Transfers	749	6,139	719.6%
Anticipated Resources	80,457	77,210	-4.0%
Existing-Other Capacity	0	0	-
Prospective Resources	80,457	77,210	-4.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin		16.9%	
Prospective Reserve Margin		16.9%	
Reference Margin Level		14.3%	

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2020 SRA**	**2021 SRA**	**2020 vs. 2021 SRA**
Demand Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Total Internal Demand (50/50)	25,145	24,751	-1.6%
Demand Response: Available	144	332	129.9%
Net Internal Demand	25,001	24,419	-2.3%
Resource Projections	**Megawatts (MW)**	**Megawatts (MW)**	**Net Change (%)**
Existing-Certain Capacity	29,440	26,850	-8.8%
Tier 1 Planned Capacity	477	188	-60.6%
Net Firm Capacity Transfers	0	866	-
Anticipated Resources	29,917	27,904	-6.7%
Existing-Other Capacity	0	0	-
Prospective Resources	29,917	27,904	-6.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.7%	14.3%	-5.4
Prospective Reserve Margin	19.7%	14.3%	-5.4
Reference Margin Level	10.0%	9.8%	-0.2

Variable Energy Resource Contributions

Because electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The table below shows the capacity contribution of existing wind and solar resources for each assessment area.

BPS Variable Generation Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	26,829	3,872	14%	725	469	65%	2,440	2,361	97%
MRO-Manitoba Hydro	259	43	17%	-	-	-	5,461	4,903	90%
MRO-SaskPower	616	66	11%	-	-	-	864	787	91%
NPCC-Maritimes	1,188	287	24%	4	-	0%	1,318	1,186	90%
NPCC-New England	1,505	166	11%	375	112	30%	3,890	2,736	70%
NPCC-New York	2,211	502	23%	57	32	56%	6,725	4,666	69%
NPCC-Ontario	4,946	678	14%	478	66	14%	9,060	5,305	59%
NPCC-Québec	3,880		0%	10		0%	41,339	32,750	79%
PJM	8,790	1,410	16%	2,421	997	41%	3,057	3,057	100%
SERC-C	964	958	99%	521	336	65%	5,005	3,572	71%
SERC-E	-	-	-	649	641	99%	3,131	3,085	99%
SERC-FP	-	-	-	3,624	2,049	57%	-	-	-
SERC-SE	-	-	-	2,735	2,282	83%	3,242	3,288	101%
SPP	26,885	4,670	17%	275	252	92%	5,441	5,130	94%
Texas RE-ERCOT	31,829	8,565	27%	7,608	6,086	80%	556	474	85%
WECC-AB	2,219	162	7%	314	202	64%	894	378	42%

BPS Variable Generation Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
WECC-BC	717	142	20%	2	1	50%	16,334	10,088	62%
WECC-CAMX	7,686	1,089	14%	16,918	10,442	62%	11,821	5,993	51%
WECC-NWPP-US-RMRG	16,180	2,318	14%	5,234	4,028	77%	40,992	20,986	51%
WECC-NWPP-SRSG	3,141	636	20%	1,797	1,265	70%	1,303	558	43%
EASTERN INTERCONNECTION	69,446	12,378	18%	9,005	5,463	61%	49,185	39,183	80%
QUÉBEC INTERCONNECTION	3,880	-	0%	10	-	0%	41,339	32,750	79%
TEXAS INTERCONNECTION	31,829	8,565	27%	7,608	6,086	80%	556	474	85%
WECC INTERCONNECTION	29,943	4,347	15%	24,256	15,938	66%	71,344	38,003	53%
TOTAL-NERC	**135,097**	**25,290**	**19%**	**40,887**	**27,488**	**67%**	**162,425**	**110,410**	**68%**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2022 Summer Reliability Assessment

May 2022

Table of Contents

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, 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 Regional Entities boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entities 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 *2022 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* 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 NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects NERC and the ERO Enterprise'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 summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment provides an evaluation of generation resource and transmission system adequacy and energy sufficiency to meet projected summer peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC has highlighted in the *2021 Long-Term Reliability Assessment* and other earlier reliability assessments and reports.

The following findings are NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the 2022 summer:

Summer Resource Adequacy Assessment and Energy Risk Analysis

- **Midcontinent ISO (MISO) faces a capacity shortfall in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions.** Capacity shortfall projections reported in the *2021 LTRA* and as far back as the *2018 LTRA* have continued. Load serving entities in 4 of 11 zones entered the annual planning resource auction (PRA) in April 2022 without enough owned or contracted capacity to cover their requirements. Across MISO, peak demand projections have increased by 1.7% since last summer due in part to a return to normal demand patterns that have been altered in prior years by the pandemic. However, more impactful is the drop in capacity in the most recent PRA: MISO will have 3,200 MW (2.3%) less generation capacity than in the summer of 2021. System operators in MISO are more likely to need operating mitigations, such as load modifying resources or non-firm imports, to meet reserve requirements under normal peak summer conditions. More extreme temperatures, higher generation outages, or low wind conditions expose the MISO North and Central areas to higher risk of temporary operator-initiated load shedding to maintain system reliability.
- **At the start of the summer, a key transmission line connecting MISO's northern and southern areas will be out of service.** Restoration continues on a 4-mile section of 500 kV transmission line that was damaged by a tornado during severe storms on December 10, 2021. The transmission outage affects 1,000 MW of firm transfers between the Midwestern and Southern MISO system that includes parts of Arkansas, Louisiana, and Mississippi. The transmission line is expected to be restored at the end of June 2022.
- **Anticipated resource capacity in Saskatchewan will be strained to meet peak demand projections, which have risen by over 7.5% since 2021.** SaskPower is projected to remain above their planning reserve margin threshold and have sufficient operating reserves for normal peak conditions. However, external assistance is expected to be needed in extreme conditions that cause above-normal generator outages or demand.
- **Drought conditions create heightened reliability risk for the summer.** Drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand:
  - **Energy output from hydro generators throughout most of the Western United States is being affected by widespread drought and below-normal snowpack.** Dry hydrological conditions threaten the availability of hydroelectricity for transfers throughout the Western Interconnection. Some assessment areas, including WECC's California-Mexico (CA/MX) and Southwest Reserve Sharing Group (SRSG), depend on substantial electricity imports to meet demand on hot summer evenings and other times when variable energy resource (e.g., wind, solar) output is diminishing. In the event of wide-area extreme heat event, all U.S. assessment areas in the Western Interconnection are at risk of energy emergencies due to the limited supply of electricity available for transfer.
  - **Extreme drought across much of Texas can produce weather conditions that are favorable to prolonged, wide-area heat events and extreme peak electricity demand.** Resource additions to the ERCOT system in recent years—predominantly solar and some wind—have raised Anticipated Reserve Margins above Reference Margin Levels and ease concerns of capacity shortfalls for normal peak demand. However, extreme heat increases peak demand and can be accompanied by weather patterns that lead to increased forced outages or reduced energy output from resources of all types. A combination of extreme peak demand, low wind, and high outage rates from thermal generators could require system operators to use emergency procedures, up to and including temporary manual load shedding.
  - **As drought conditions continue over the Missouri River Basin, output from thermal generators that use the Missouri River for cooling in Southwest Power Pool (SPP) may be affected in summer months.** Low water levels in the river can impact generators with once-through cooling and lead to reduced output capacity. Energy output from hydro generators on the river can also be affected by drought conservation measures implemented in the reservoir system. Outages and reduced output from thermal and hydro generation could lead to energy shortfalls at peak demand. Periods of above normal wind generator output may give some relief, however, this energy is not assured. System operators could require emergency procedures to meet peak demand during periods of high generator unavailability.

- **All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions.** Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions. Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate.

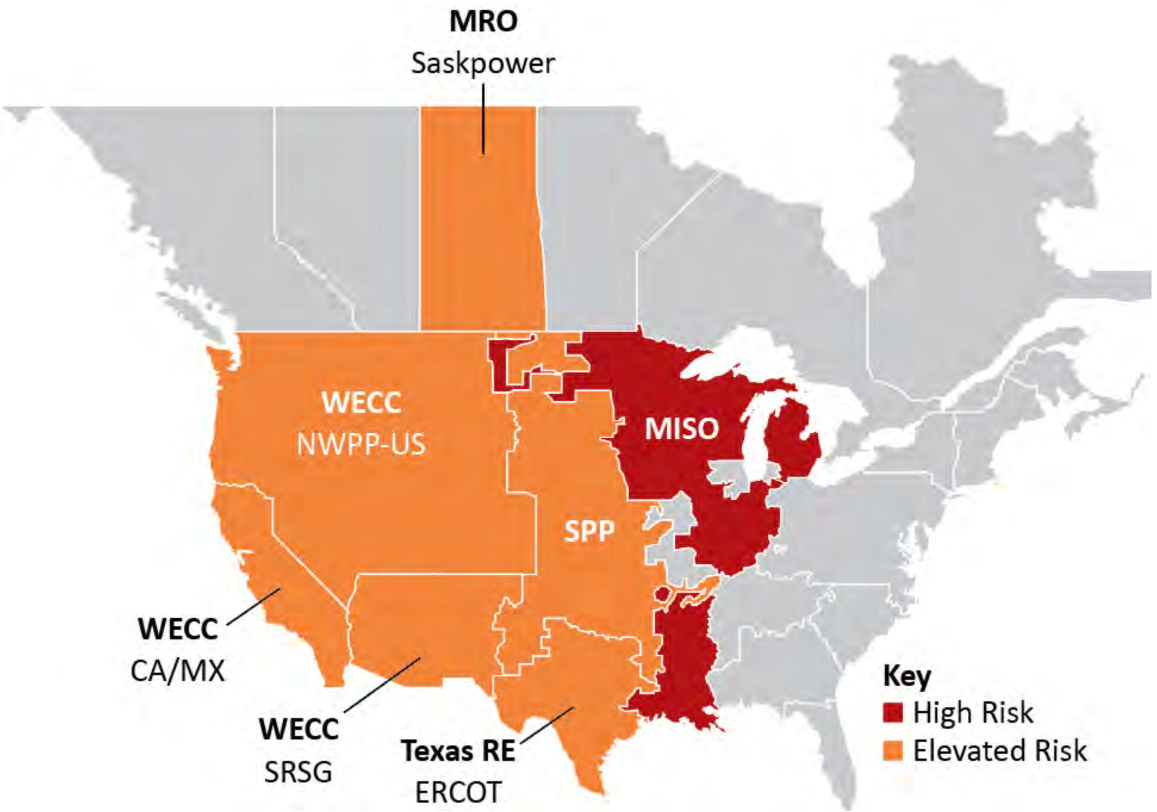


Figure 1: Summer Reliability Risk Area Summary

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

Other Reliability Issues for Summer

- **Supply chain issues and commissioning challenges on new resource and transmission projects are a concern in areas where completion is needed for reliability during summer peak periods.** Assessment areas report that some generation and transmission projects are being impacted by product unavailability, shipping delays, and labor shortages. At the time of this assessment publication, WECC-CA/MX, and WECC-SRSG have sizeable amounts of generation capacity in development and included in their resource projections for summer. In Texas (ERCOT), transmission expansion projects are underway to alleviate transmission constraints and maintain system stability as the BPS is adapted to rapid growth in new generation; delays or cancellations of transmission projects can cause transmission system congestion during peak conditions and affect the ability to serve load in localized areas. Should project delays emerge, affected Generator Owners (GOs) and Transmission Owners must communicate changes to Balancing Authorities (BAs), Transmission Operators, and Reliability Coordinators, so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.
- **Coal-fired GOs are having difficulty obtaining fuel and non-fuel consumables as supply chains are stressed.** No specific BPS reliability impacts are currently foreseen; however, coal stockpiles at power plants are relatively low compared to historical levels. Some owners and operators report challenges in arranging replenishment due to mine closures, rail shipping limitations, and increased coal exports. Some GOs have implemented controls to maintain sufficient stocks for peak months while BAs and Reliability Coordinators are continuing to conduct fuel surveys and monitoring the situation.
- **The electricity and other critical infrastructure sectors face cyber security threats from Russia and other potential actors amid heightened geopolitical tensions in addition to ongoing cyber risks.** Russian attackers may be planning or attempting malicious cyber activity to gain access and disrupt the electric grid in North America in retaliation for support to Ukraine. The Electricity Infrastructure Sharing and Analysis Center (E-ISAC) continues to exchange information with its members and has posted communications and guidance from government partners and other advisories on its Portal. E-ISAC members are encouraged to check in regularly to receive updates and to actively share information regarding threats and other malicious activities with the E-ISAC to enable broader communication with other sector participants and government partners.
- **Unexpected tripping of solar photovoltaic (PV) resources during grid disturbances continues to be a reliability concern.** In May and June 2021, the Texas Interconnection experienced widespread solar PV loss events like those previously observed in the California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California.

- During these events, widespread loss of solar PV resources was also coupled with the loss of synchronous generation, unintended interactions with remedial action schemes, and some tripping of distributed energy resources. As industry urgently takes steps to address systemic reliability issues through modeling, planning, and interconnection processes, system operators in areas with significant amounts of solar PV resources should be aware of the potential for resource loss events during grid disturbances.
- **An active late-summer wildfire season in the Western United States and Canada is anticipated, posing BPS reliability risks.** Government agencies warn of the potential for above-normal wildfire risk beginning in June across much of Canada, in the U.S. South Central states, and Northern California. If drought conditions persist, the fire outlook for late summer would likely extend across the Western half of North America. The interconnected transmission system can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to dry weather and ground conditions. In addition, smoke from wildfires can cause diminished output from solar PV resources, and electricity supply will be affected by lower output from BPS-connected solar PV resources. Conversely, system demand may increase as part of distribution demand served by rooftop solar PV is less in smoky conditions.

ERO Actions to Reduce Risks of Unexpected Solar PV Tripping

Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred as recently as Summer 2021. A common thread with these events is the lack of inverter-based resource (IBR) ride-through capability causing a minor system disturbance to become a major disturbance. The latest disturbance report reinforces that improvements to NERC Reliability Standards are needed to address systemic issues with IBRs. At a high level, these include the following:

- **Performance-Based Requirements:** A number of NERC Reliability Standards require documentation that demonstrates compliance with the requirement (i.e., PRC-024-3); however, they do not specify a certain degree of performance that must be met. NERC has initiated action against this issue by developing a standards authorization request and strongly recommends that PRC-024 be retired and replaced with a comprehensive ride-through standard that focuses specifically on the generator protections and controls.
- **Performance Validation Requirement:** NERC has initiated action against this issue by developing a reliability guideline on interconnection requirements as well as issuing recommendations from recent disturbance reports. NERC strongly recommends that a performance validation standard be developed that ensures that Reliability Coordinators, Transmission Operators, or BAs are assessing the performance of interconnected facilities during grid disturbances, identifying any abnormalities, and executing corrective actions with affected facility owners to eliminate these issues. This requires entities to have strong interconnection requirements as NERC highlights in its reliability guidelines and disturbance reports.
- **Electromagnetic Transient Modeling and Model Quality Assurance:** NERC has initiated action against this issue by issuing recommendations in recent disturbance reports and strongly recommends that electromagnetic transient (EMT) modeling and studies be incorporated into NERC Reliability Standards to ensure that adequate reliability studies are conducted to ensure reliable operation of the BPS moving forward. Existing positive sequence simulation platforms have limitations in their ability to identify possible performance issues, many of which can be identified using EMT modeling and studies. As the penetration of IBRs continues to grow across North America, the need for EMT modeling and studies will only grow exponentially. Furthermore, NERC Reliability Standards need enhancements to ensure that model accuracy and model quality checks are explicitly defined.

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of North America this summer (see Figure 2). In addition, drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand.[1] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as increases in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

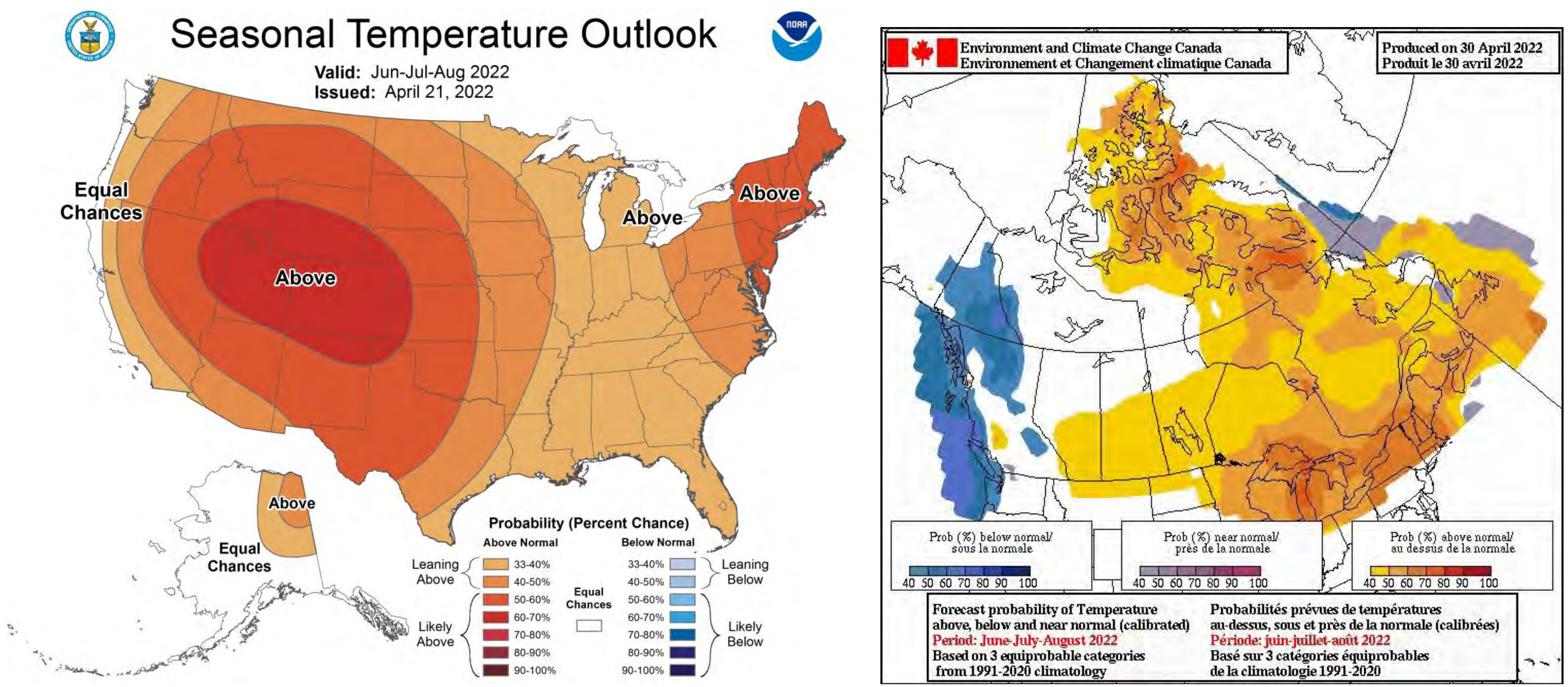


Figure 2: United States and Canada Summer Temperature Outlook[2]

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[1] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[2] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Above-normal fire risk at the beginning of the summer exists in much of Canada as well as in the U.S. South Central states, Northern California, and Oregon, setting the stage for an active fire season at the beginning of the summer (see **Figure 3**). In late summer, hotter and drier conditions are expected to cause elevated fire risk in California and the U.S. West Coast. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

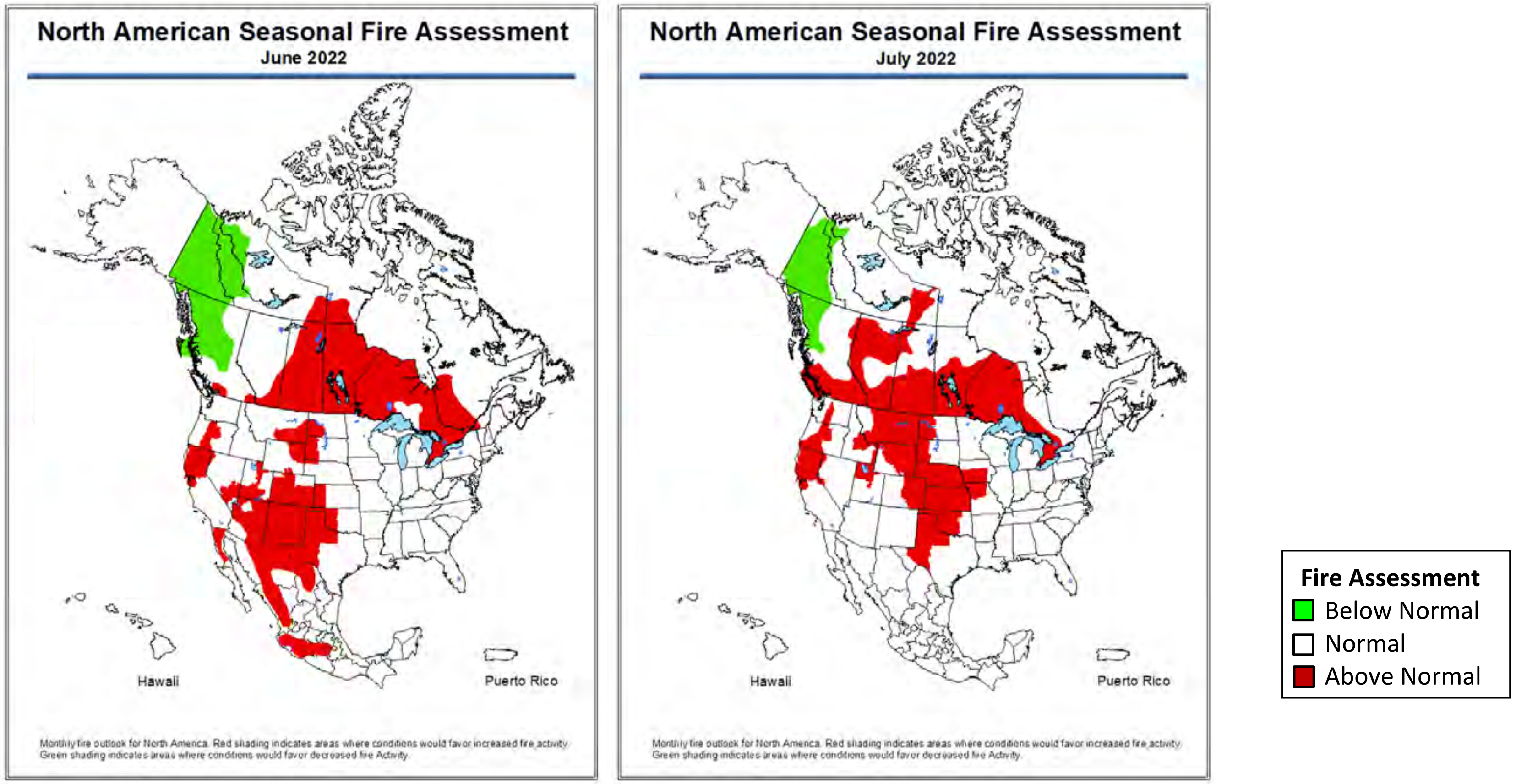

Figure 3: North American Seasonal Fire Assessment for June and July 2022[3]

Wildfire prevention planning in California and other areas includes power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the ERO published the *Wildfire Mitigation Reference Guide*[4] to promote preparedness within the North American electricity power industry and share the experience and practices from utilities in the Western Interconnection.

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[3] *See North American Seasonal Fire Assessment and Outlook*, April 2022: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf
[4] See the NERC *Wildfire Mitigation Reference Guide*, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

Risk Discussion

WECC: Western Interconnection

An elevated risk of energy emergencies persists across the U.S. Western Interconnection this summer as dry hydrological conditions threaten the availability of hydroelectric energy for transfer. Periods of high demand over a wide area will result in reduced supplies of energy for transfer, causing operators to rely primarily on alternative resources for system balancing, including natural-gas-fired generators and battery systems.

Throughout the Western Interconnection, BAs rely on flexible resources to support balancing the increasingly weather-dependent load with the variable energy generation within the resource mix. Dispatchable generation from hydroelectric and thermal plants internal to the BA's area as well as imports of surplus energy in another area are called upon by operators when area shortfalls are anticipated. Under normal conditions, there is sufficient energy and resource capacity and an adequate transmission network for transfers between areas to meet system ramping needs. However, conditions like wide-area heat events can reduce the availability of resources for transfer as areas serve higher internal demands. Additionally, transmission networks can become stressed when events like wildfires or wide-area heatwaves cause network congestion. The growing reliance on transfers within the Western Interconnection and falling resource capacity in many adjacent areas increases the risk that extreme events will lead to load interruption.

Recent Heatwave Events in the Western Interconnection

From August 14 through August 19, 2020, the Western United States suffered an intense and prolonged heatwave that affected many areas across the Western Interconnection.[5] Because of above-average temperatures, generation and transmission capacity struggled to keep up with increased electricity demand. Throughout many supply-constrained hours over this same period, generation resource output was below preseason peak forecasts for nearly all resource types, including natural gas, wind, solar, and hydroelectric. During the event, 10 Western Interconnection BAs issued 18 separate energy emergency alerts (EEA). The impacts of the August heatwave struck the entirety of the Western Interconnection and caused a peak demand record of 162,017 MW on August 18, 2020, at 4:00 p.m. Mountain time. Although demand peaked on August 18, the most severe reliability consequence of the heatwave event occurred at the beginning, when 1,087 MW of firm load was shed on August 14 and 692 MW was shed on August 15 in California. System operators at the California ISO initiated rotating electricity outages to reduce demand during early evening hours so that operating reserves would be sufficient to prevent even greater consequences for the system.

The West experienced another wide-area extreme temperature event in 2021. From late-June through mid-July, high temperatures extended over a broad area that included Northern California, Idaho, Western Nevada, Oregon, and Washington state in the United States as well as in British Columbia and (in its latter phase) Alberta, Manitoba, the Northwest Territories, Saskatchewan, and Yukon areas in Canada. Temperatures reached 121 degrees Fahrenheit in some areas, and peak demand records were set in British Columbia and Alberta. BAs in California, the U.S. Northwest, and the Canadian province of Saskatchewan issued EEAs.

In summer, WECC's CA/MX, the Northwest Power Pool (NWPP), and SRSG assessment areas can be exposed to greater risk of resource shortfalls for the hours that immediately follow afternoon peak demand. The reason the risk is greater in these hours is that solar resource output is diminishing with the setting sun while demand is still near its daily high. The scenarios for all three areas shown in **Figure 4** illustrate (six charts) how the need for imports changes from the peak demand hour to the higher risk hours that follow; see the **Data Concepts and Assumptions** for more information about these charts. Anticipated resources in the high risk hours are lower than the on peak hours due to reduced solar PV output. During periods of peak demand and normal forced outages, anticipated resources in each assessment area provide the needed energy to ensure demand and operating reserve requirements are met. Demand or resource derates from extreme conditions that cannot be remedied with imports will result in energy emergencies and the potential for load shedding. In prior summers, only CA/MX had greatest risk exposure in hours after peak demand; off-peak risk has increased in other parts of the Western Interconnection this year.

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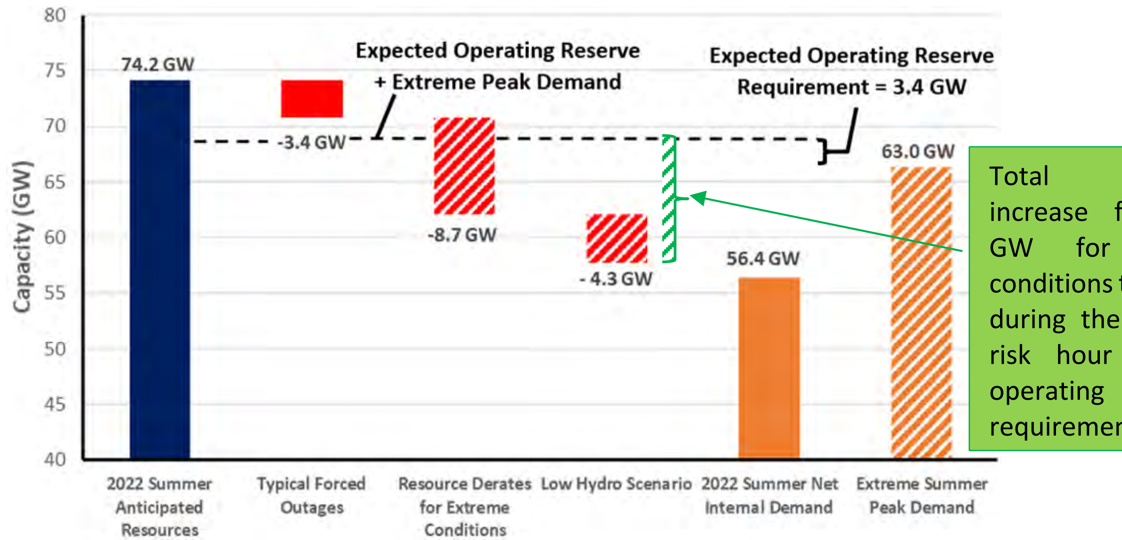
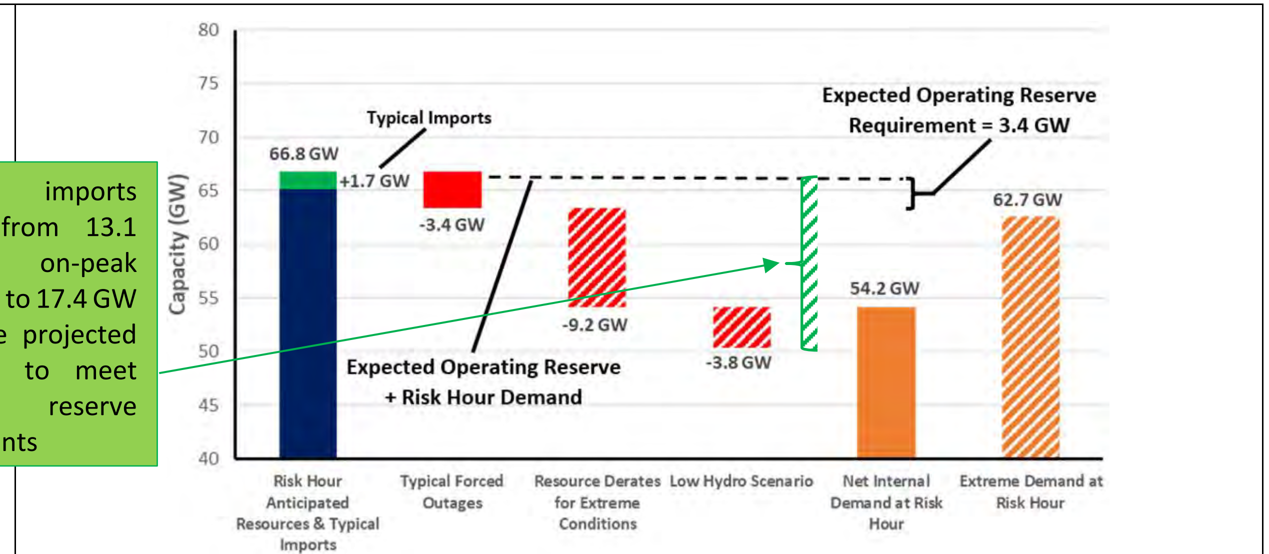
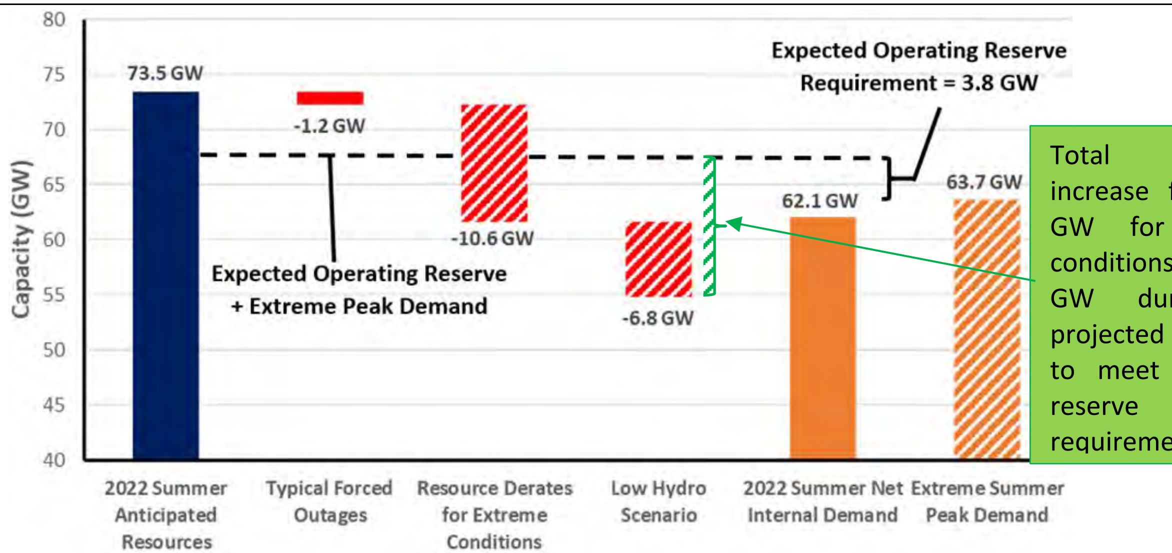
[5] WECC August Heat Wave Event information: WECC's *August Heat Wave Analysis* Presentation



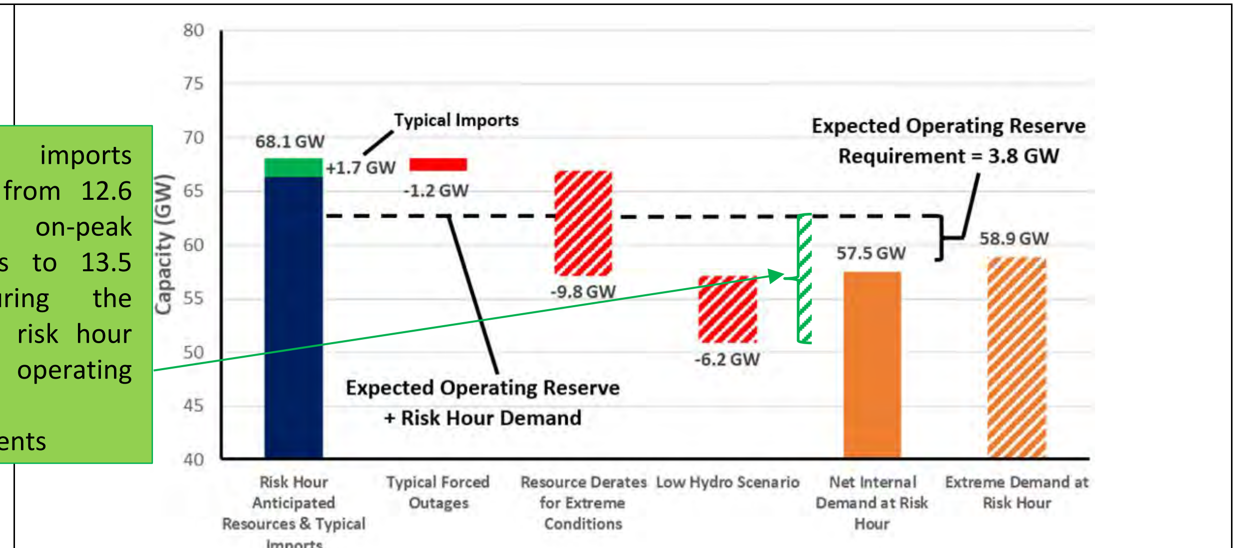
WECC-CA/MX On-Peak



WECC-CA/MX Risk Hour (8:00 p.m. local)

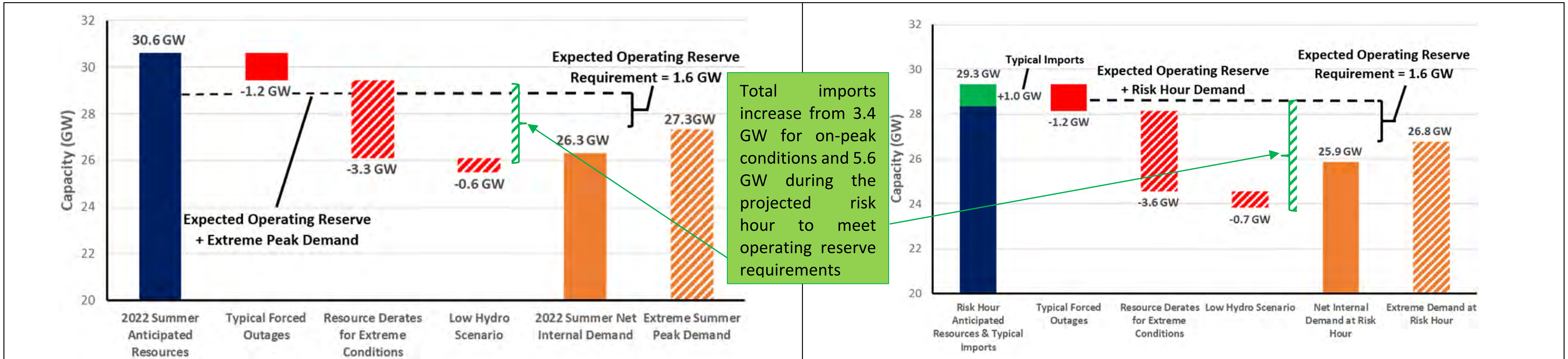


WECC-NWPP-US On-Peak



WECC-NWPP-US Risk Hour (7:00 p.m. local)

Figure 4: Risk Scenarios for WECC U.S. Assessment Areas



WECC-SRSG On-Peak	WECC-SRSG Risk Hour (7:00 p.m. local)

Figure 4 (continued): Risk Scenarios for WECC U.S. Assessment Areas

WECC performed probabilistic studies and identified a continued risk of energy shortfalls for the WECC-CA/MX area. Their analysis models expected demand and resource contribution over all hours and accounts for variability with historical distributions. Assuming that the nearly 3.4 GW of new resource additions come into service in California for the summer, the Loss-of-Load Hours (LOLH) metric of projected hours with insufficient resources to meet planning reserve criteria will be one hour for the California portion. In a scenario without the new resource additions, the LOLH increases to four hours. Expected unserved energy (EUE) in California for these two scenarios is 4 MWh and 8,755 MWh, respectively. In the Mexico portion of CA/MX, LOLH of 10 and 14 hours and EUE of 100 and 200 MWh, respectively, are projected. All other WECC assessment areas have negligible load-loss and unserved energy for the summer. WECC's probabilistic study modeling includes non-firm transfers between WECC assessment areas and provides a wide-area assessment of resource adequacy. The WECC studies show that, as more areas experience the same high-demand conditions during wide-area heat events, the supply of electricity for transfer across the Interconnection is reduced and the risk of unserved energy increases.

Risk Assessments of Resource and Demand Scenarios

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 summer 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 1**, 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. Highlighted areas are identified as having resource adequacy or energy risks for the summer in the key findings discussion. The typical outages reserve margin is comprised of anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the 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.

Extreme generation outages, low resource output, and peak loads similar to those experienced in August 2020 are reliability risks in certain areas for the upcoming summer. When forecasted resources fall below expected demand, grid operators would need to employ operating mitigations or EEAs to obtain the capacity and energy 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.

Table 1: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	21.1%	3.2%	-8.3%
MRO-Manitoba	27.3%	21.5%	7.8%
MRO-SaskPower	12.2%	2.6%	-5.3%
NPCC-Maritimes	39.2%	28.7%	11.7%
NPCC-New England	20.6%	9.3%	-2.5%[6]
NPCC-New York	30.4%	22.4%	13.5%
NPCC-Ontario	18.0%	18.0%	3.0%
NPCC-Québec	40.3%	40.3%	35.0%
PJM	31.7%	23.9%	16.1%
SERC-Central	18.3%	10.7%	3.3%
SERC-East	21.4%	18.3%	11.3%
SERC-Florida Peninsula	20.7%	17.3%	15.1%
SERC-Southeast	29.8%	25.4%	17.4%
SPP	30.6%	12.3%	-4.7%
Texas RE-ERCOT	22.0%	15.9%	1.1%
WECC-NWPP-AB	19.7%	17.2%	5.3%
WECC-NWPP-BC	39.3%	39.1%	10.4%
WECC-CA/MX	31.5%	25.4%	-13.1%
WECC-NWPP-US	18.3%	16.3%	-13.8%
WECC-SRSG	16.3%	11.8%	-6.8%

[6] Energy and capacity is sufficient for a broad range of normal and above-normal scenarios in the NPCC-New England area for the summer. This negative reserve margin indicates that a scenario combining extreme high demand and extremely-low resources could, however, result in an energy emergency.

Transfers in a Wide-Area Event

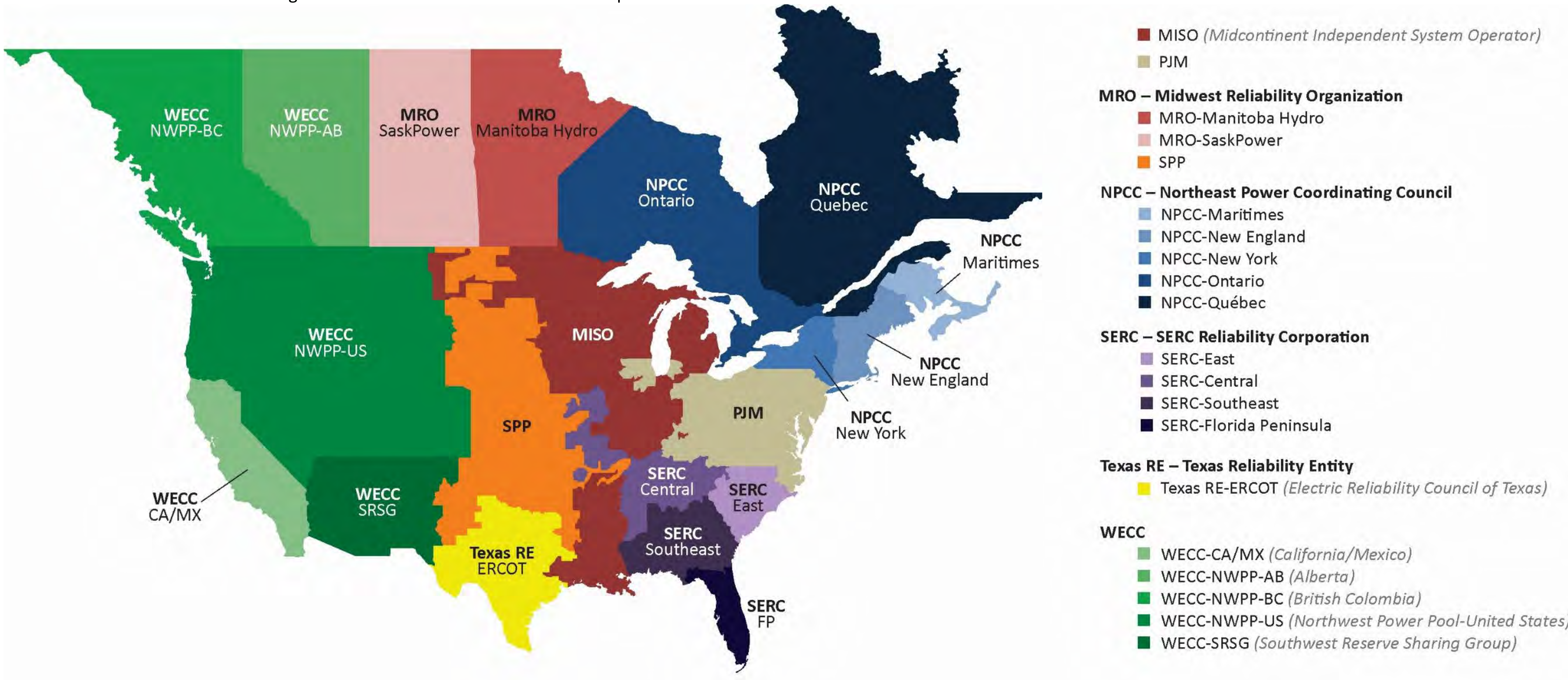
When above-normal temperatures extend over a wide area, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Some assessment areas expect imports from other areas to be available to meet periods of peak demand and have contracted for firm transfer commitments. A summary of area firm on-peak imports and exports is shown in **Table 3**. Firm resource transactions like 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 summer seasons are shown in **Table 3**; the data in this table is sourced from the data adequacy tables in the **Data Concepts and Assumptions** section. In the unlikely event that multiple assessment areas are experiencing energy emergencies as could occur in a wide-area heatwave, 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.

Table 3: 2021 and 2022 On-Peak Net Firm Transfers

Assessment Area	2021 Summer Transfers (MW)	2022 Summer Transfers (MW)	Year-to-Year Change
MISO	2,979	1,353	-54.6%
MRO-Manitoba	-1,596	-1,816	13.8%
MRO-SaskPower	125	290	132.0%
NPCC-Maritimes	-57	64	-212.3%
NPCC-New England	1,208	1,292	7.0%
NPCC-New York	1,816	2,465	35.7%
NPCC-Ontario	80	150	87.5%
NPCC-Québec	-1,995	-2,304	15.5%
PJM	1,460	124	-91.5%
SERC-Central	172	-795	-561.6%
SERC-East	562	612	8.9%
SERC-Florida Peninsula	1,007	300	-70.2%
SERC-Southeast	-1,115	-2,524	126.4%
SPP	186	-144	-177.6%
Texas RE-ERCOT	210	20	-90.5%
WECC-AB	0	437	N/A
WECC-BC	0	0	N/A
WECC-CA/MX	686	0	-100.0%
WECC-NWPP-US	6,139	2,517	-59.0%
WECC-SRSG	866	1,002	15.7%

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer 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 SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.

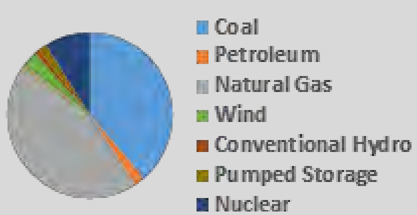


MISO

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

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

On-Peak Fuel Mix



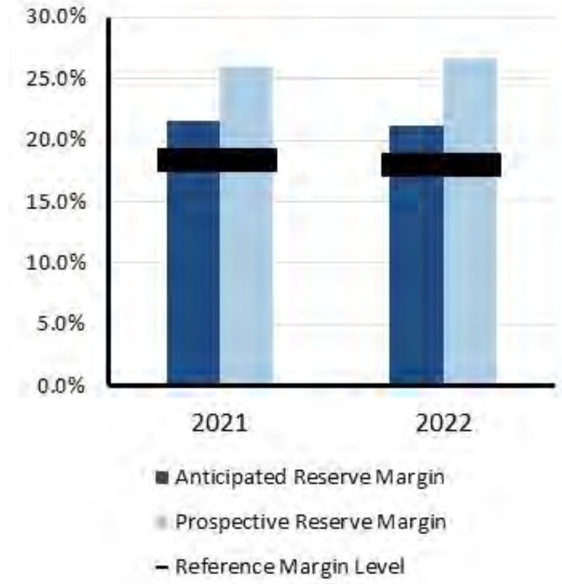
Highlights

- Tighter than normal operating conditions are anticipated, particularly in the MISO North/Central region, which cleared too little capacity in the 2022–2023 PRA. The PRA capacity shortfall of 1,230 MW signals a potential for operating risk during peak summer conditions.
- Continued operating measures, such as MISO maximum generation events, can be expected in order to give system operators access load modifying resources (demand response) that can only be called upon once available generation is at maximum capacity.
- MISO performs an annual loss-of-load expectation (LOLE) study to determine its installed reserve margin and other probabilistic reliability indices. Based on results of the 2021 analysis, MISO expects low amounts of EUE in the summer season. The greatest risk occurs in the month of July, coinciding with the typical peak in annual demand.

Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding 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 (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year 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

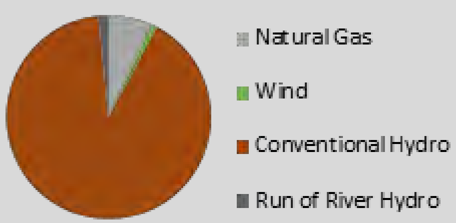
Operational Mitigations: Total of 2.4 GW capacity resources available during extreme operating conditions

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



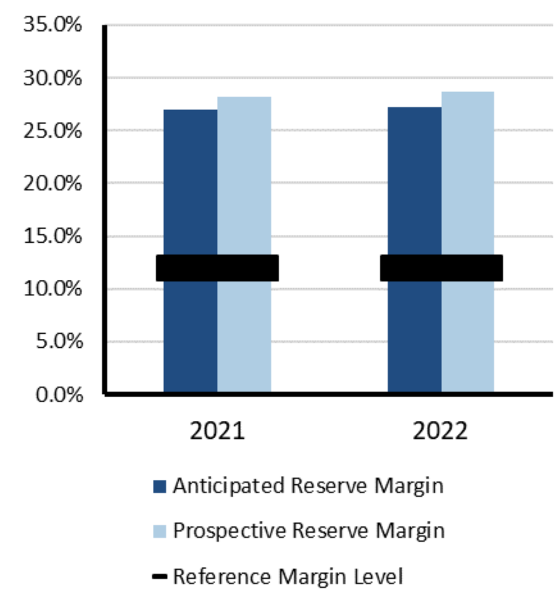
Highlights

- Manitoba Hydro is not anticipating any emerging reliability issues in its assessment area for the upcoming season.
- Four Keeyask hydro units were added this past year (approximately 93 MW each). Two additional Keeyask generating units are anticipated to come on line for Summer 2022, and these are listed as Planned Tier 1 generation.
- There are no significant seasonal reliability issues identified in neighboring assessment areas that have the potential to impact Manitoba Hydro operations.
- The probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a very low risk of resource adequacy issues.

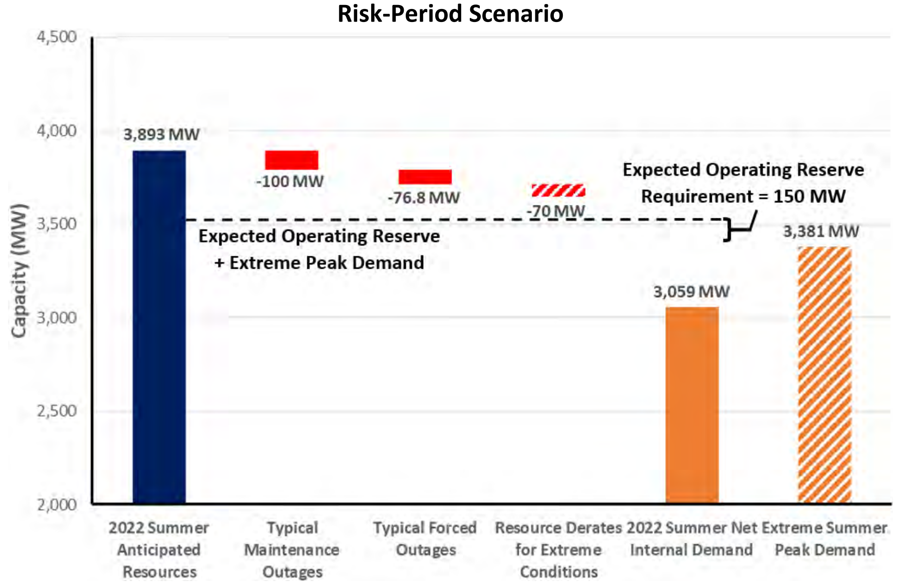
Risk Scenario Summary

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 minimum probability of exceedance forecast load

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

Extreme Derates: Brandon units 6 and 7 summer capacity temperature derates

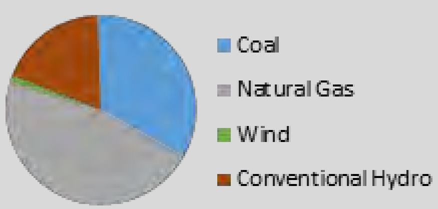
MRO-SaskPower

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



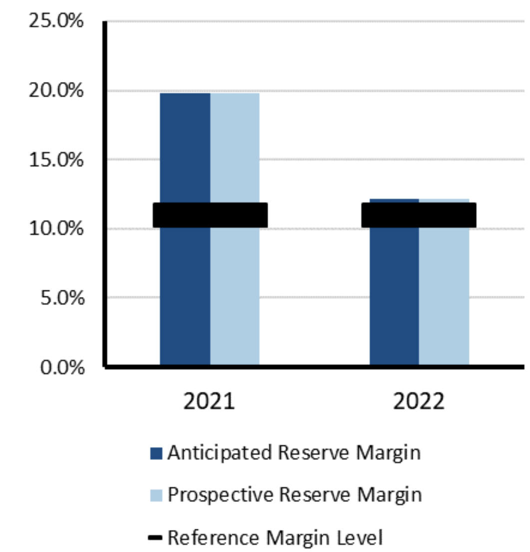
Highlights

- Saskatchewan experiences high load in summer as a result of extreme hot weather.
- SaskPower conducts an annual summer 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 outages combine with large planned maintenance outages during peak load times in May, June, July, August, and October.
- In case of extreme thermal 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.
- SaskPower has performed a probability-based capacity adequacy study to assess risk of high forced outages that would lead to the use of emergency operating procedures. Forced outages of 300 MW or greater that coincide with peak demand may result in demand response and potential load interruptions to maintain system balance. There is an 8.2% probability of having forced outages of 300 MW or greater this summer.

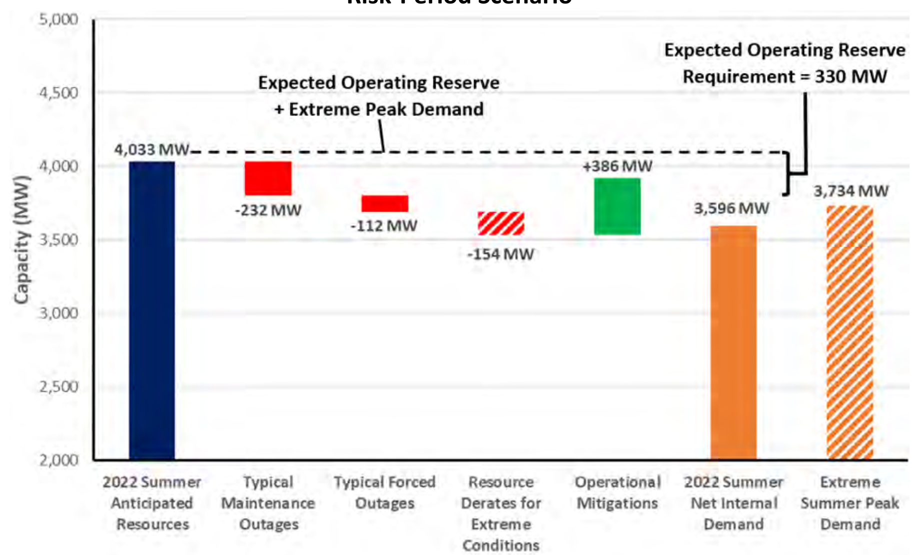
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage 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 summer months of June–September 2021

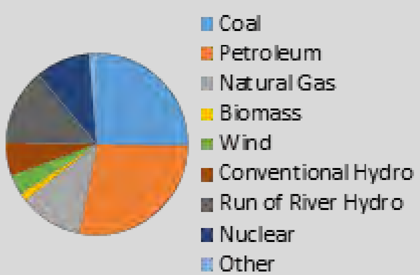
Forced Outages: Estimated by using SaskPower forced outage model

Operational Mitigations: Estimated average value based on short-term transfer capability from neighboring utilities for the upcoming 2022 summer

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 Fuel Mix



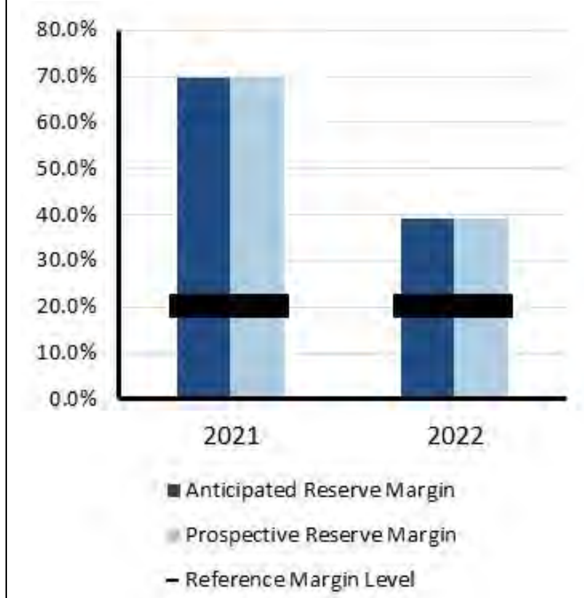
Highlights

- 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 summer operating period.
- Dual-fuel units will have sufficient supplies of heavy fuel oil on-site as part of the planning process to enable sustained operation in the event of natural gas supply interruptions.
- Based on an NPCC probabilistic assessment, the Maritimes assessment area shows a cumulative likelihood greater than 0.5 days/period of using their operating procedures and a cumulative likelihood of reducing their 30-minute reserve requirements (10 days/period) and initiating interruptible loads (5 days/period) over the 2022 summer period for the base case scenario, assuming the highest peak load levels.
- The Maritimes area is winter peaking. No significant cumulative LOLE, LOLH, and EUE risks were estimated over the summer May–September period for all scenarios simulated.

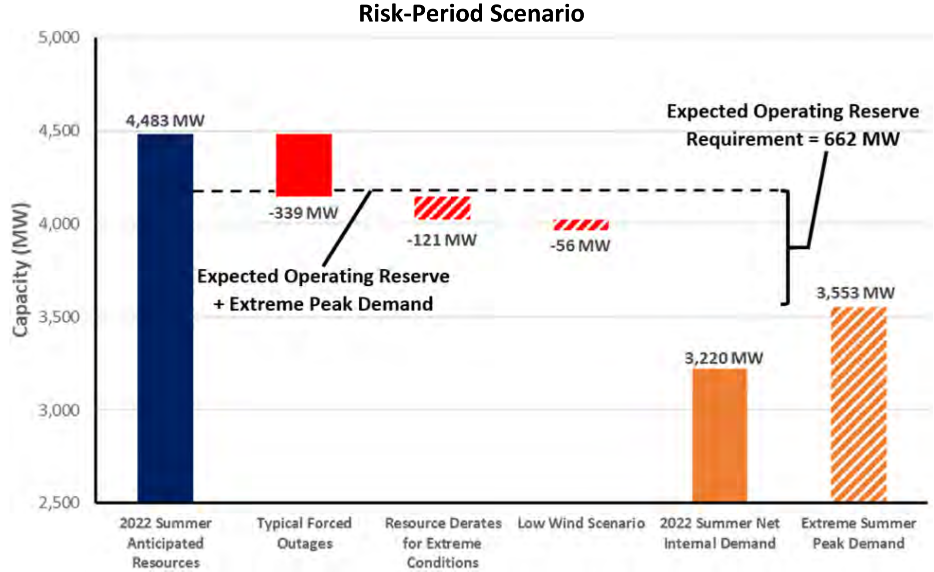
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage 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 (99/1) extreme demand forecast

Outages: Based on historical operating experience

Extreme Derates: Based on historical data for ambient temperature thermal de-rates

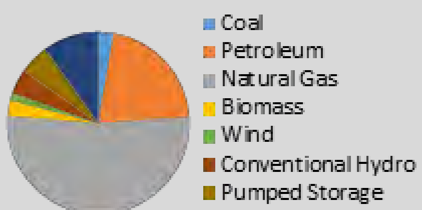
Low Wind Scenario: A low-likelihood scenario resulting in no wind resources

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

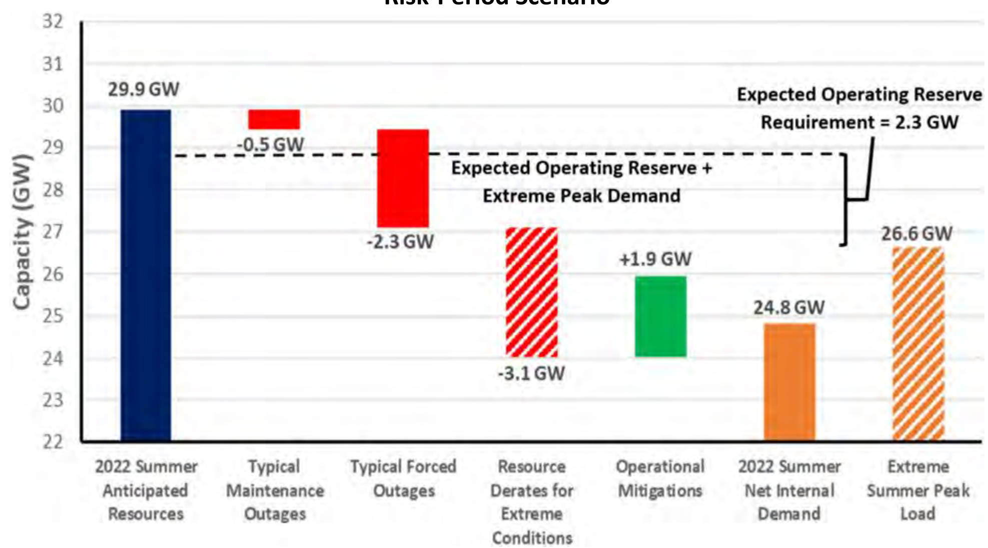
- The New England area expects to have sufficient capacity to meet the 2022 summer peak demand forecast. As of April 5, 2022, the peak summer (net internal) demand is forecast to be 24,817 MW for the week of July 24, 2022, with a projected net margin of 1,705 MW (6.9%). The 2022 summer (net internal) demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter PV systems, and distributed generation.
- Based on an NPCC probabilistic assessment, ISO-NE may rely on limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with highest peak load scenario resulted in a small estimated cumulative LOLE risk of ~0.6 days/period with associated LOLH (~2.1 hours/period) and EUE (~1,603 MWh/period) risk this is divided between June and August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of 10% reduction in NPCC resources and PJM reductions.

On-Peak Reserve Margins

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load, combined with extreme outage conditions, could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance & Forced Outages: Based on historical weekly averages

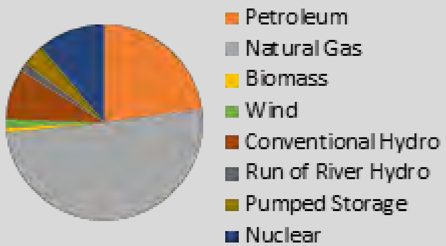
Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

Operational Mitigations: Based on load and capacity relief assumed available from invocation of 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 NYISO is the only Balancing Authority 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. 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 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 2022–2023 IRM at 19.6%."

On-Peak Fuel Mix



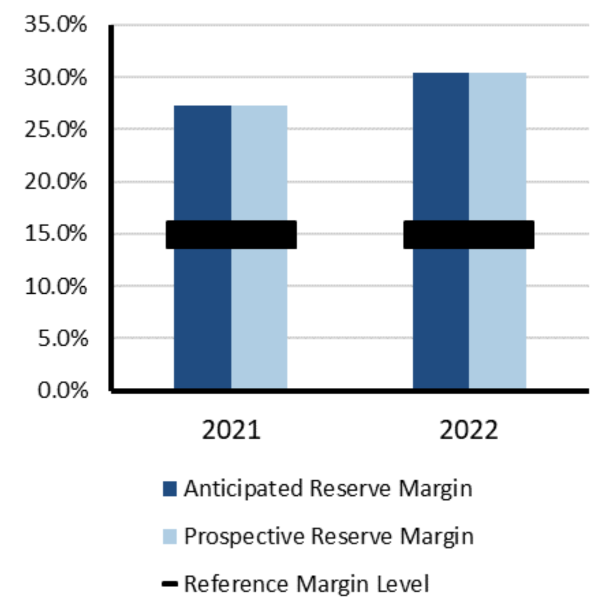
Highlights

- The NYISO is not anticipating any operational issues in the New York control area for the upcoming summer operating period. Adequate capacity margins are anticipated and existing operating procedures are sufficient to handle any issues that may occur.
- Based on an NPCC probabilistic assessment, NYISO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer. Only the highest peak load scenarios with base and reduced resource cases require operating procedures. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios.
- The analysis included simulation of a base case (normal 50/50 demand and expected resources) and a highest peak load scenario as well as including a low-likelihood reduced resource case that considers the impacts of extended maintenance in Southeastern New York, reduction in the effectiveness of demand response programs, and reduced import and transfer capabilities. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels representing an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.

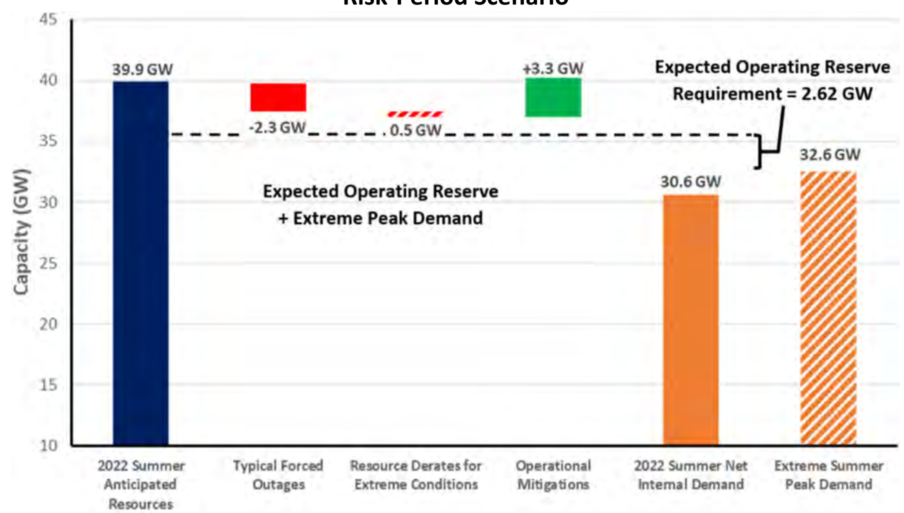
Risk Scenario Summary

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) extreme demand forecast

Forced Outages: Based on historical 5-year averages

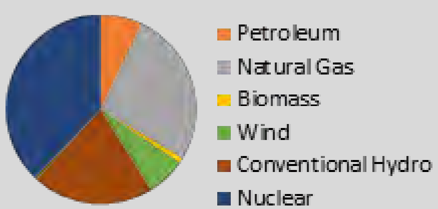
Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area *Emergency Operations Manual*

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 Fuel Mix



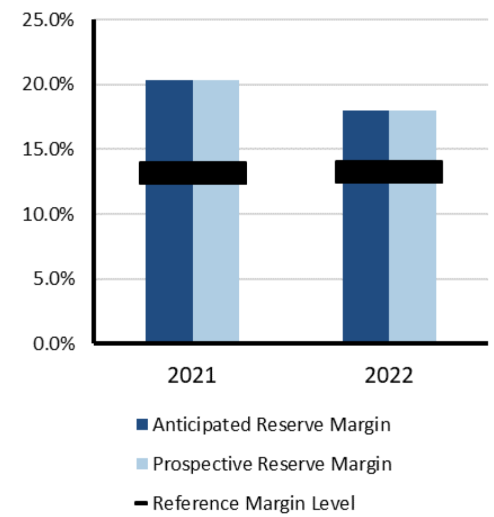
Highlights

- The ongoing transmission outage at the New York-St Lawrence interconnection continues to impact import and export capacity between Ontario and New York. This issue is expected to be resolved by the third quarter of 2022.
- Ontario is entering a period of tighter supply conditions brought on by rising demand and the ongoing nuclear refurbishment program; during summer months, planned generation maintenance outages will be more challenging to accommodate than they have been previously. Nonetheless, Ontario expects to have sufficient generation resources available to meet its needs throughout the summer of 2022, and its transmission system is expected to continue to reliably supply province-wide demand throughout the season.
- Based on an NPCC probabilistic assessment, IESO is expected to require limited use of operating procedures designed to mitigate resource shortages during the summer for the low-likelihood reduced resource case. This low-likelihood reduced resource scenario is based exclusively on the two highest load levels that represent an average 10–15% increase in peak loads over the 50/50 forecast with a combined 7% probability of occurring. Additional constraints include an estimated 10% reduction in NPCC resources and PJM reductions.
- Negligible cumulative LOLE, LOLH, and EUE risks are estimated over the May–September summer period for all simulated scenarios.

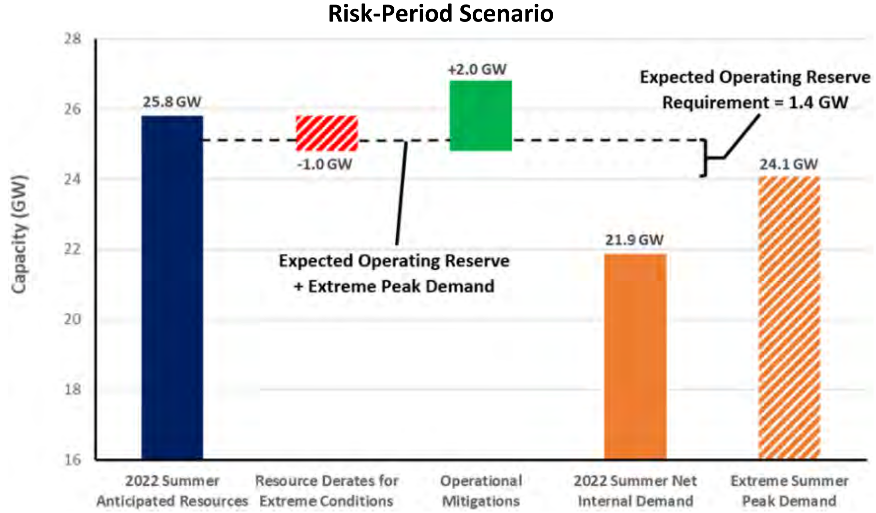
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding 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 Forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

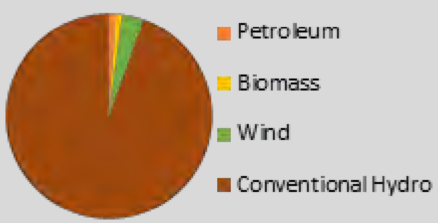
Operational Mitigations: Imports anticipated from neighbors during emergencies

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



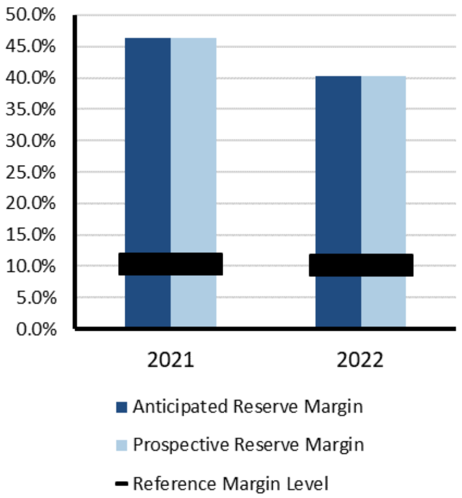
Highlights

- Québec is a winter peaking system, and no particular resource adequacy problems are forecast for the upcoming summer.
- Québec expects to be able to provide assistance to other areas if needed up to the transfer capability available.
- Québec has had no major generation or transmission additions since the *2021 NERC SRA*.
- The Québec assessment area is not expected to require use of their operating procedures that are designed to mitigate resource shortages during the summer of 2022 based on an NPCC probability assessment. The Québec area is winter peaking and has a large reserve margin for the summer period. As a result, Québec does not indicate having any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled.

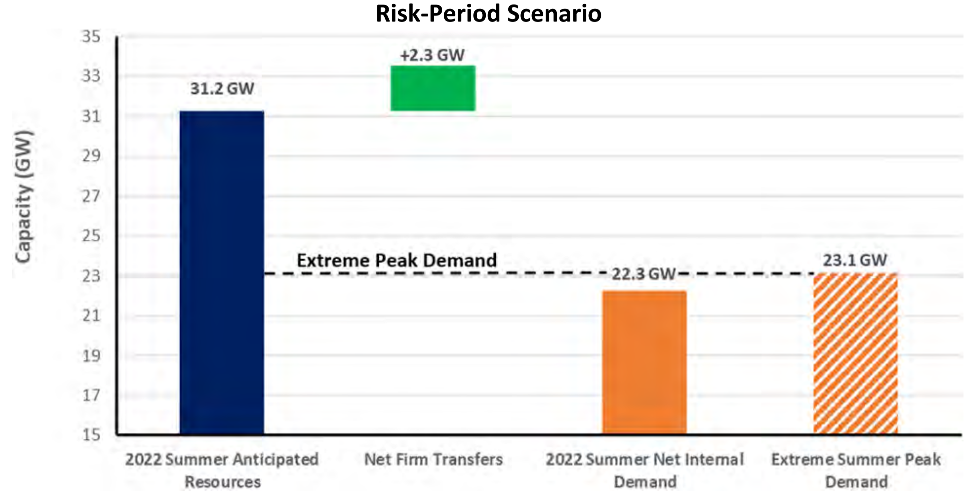
Risk Scenario Summary

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 (90/10) demand forecast

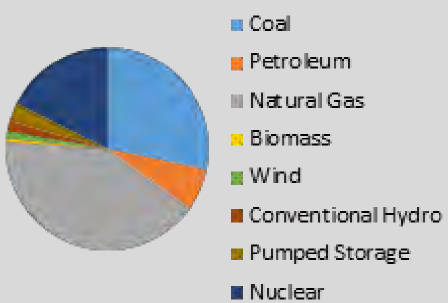
Net Firm Transfers: Imports anticipated from neighbors during emergencies

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.

On-Peak Fuel Mix



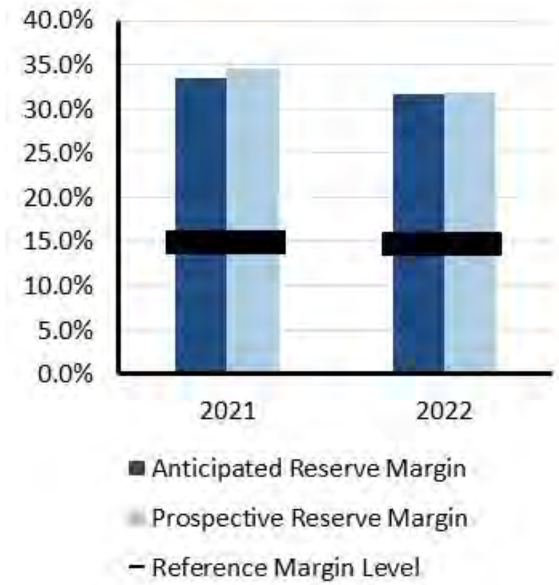
Highlights

- PJM expects no resource problems over the entire 2022 summer peak season because installed capacity is over two times the reserve requirement.
- PJM continues to request fuel inventory and supply data of coal and oil resources (including dual-fuel units). This data request, sent every two weeks, started prior to the 2021–2022 winter season as a result of increasing reports of existing and future supply shortages of fuel and non-fuel consumables. In order to maintain situational awareness throughout the spring and into the summer of 2022, PJM is continuing efforts to monitor potential impacts of fuel and non-fuel consumables supply as well as delivery status on generation resources.
- PJM is expecting a low risk of experiencing periods of resources falling below required operating reserves during Summer 2022 based on the 2021 PJM Reserve Requirement Study. As indicated in the study, PJM is forecasting around 33% installed reserves (including expected committed Demand Resources), well above the target installed reserve margin of 14.9%.
- No other reliability issues are expected.

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: 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 2.3 GW based on operational/emergency procedures

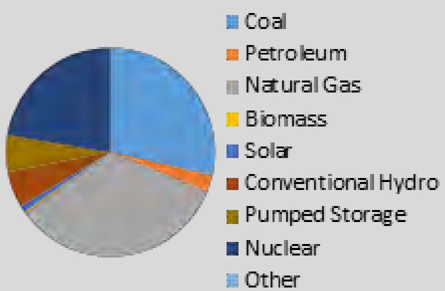
SERC-East

SERC-East is a summer-peaking assessment area within the SERC Regional Entity. 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 Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



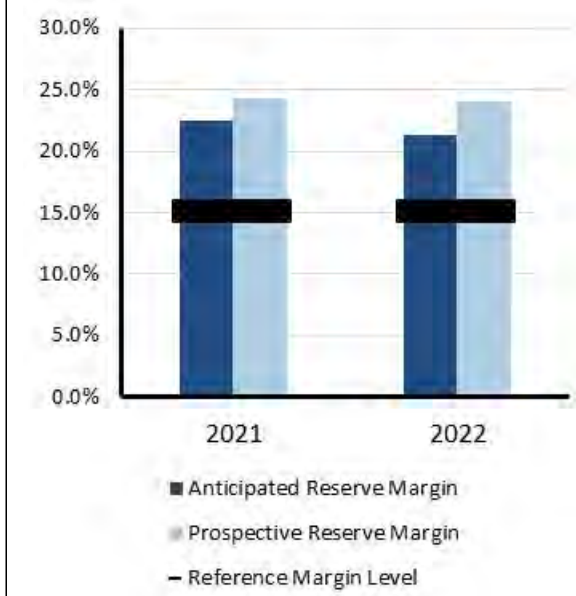
Highlights

- Entities in SERC-East have not identified any potential reliability issues for the upcoming season. The entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain system reliability. Entities reported that coal inventory is in the upper allowed range to maintain reliability.
- Entities in SERC-East continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy as well as with transfer capability.
- Entities in SERC-East are not anticipating operational challenges for the upcoming summer season.
- Probabilistic analysis performed for SERC-East shows almost no risk for resource shortfall for the summer. SERC-East has a small amount of EUE in August but a negligible amount at other times (EUE < 0.4 MWh).

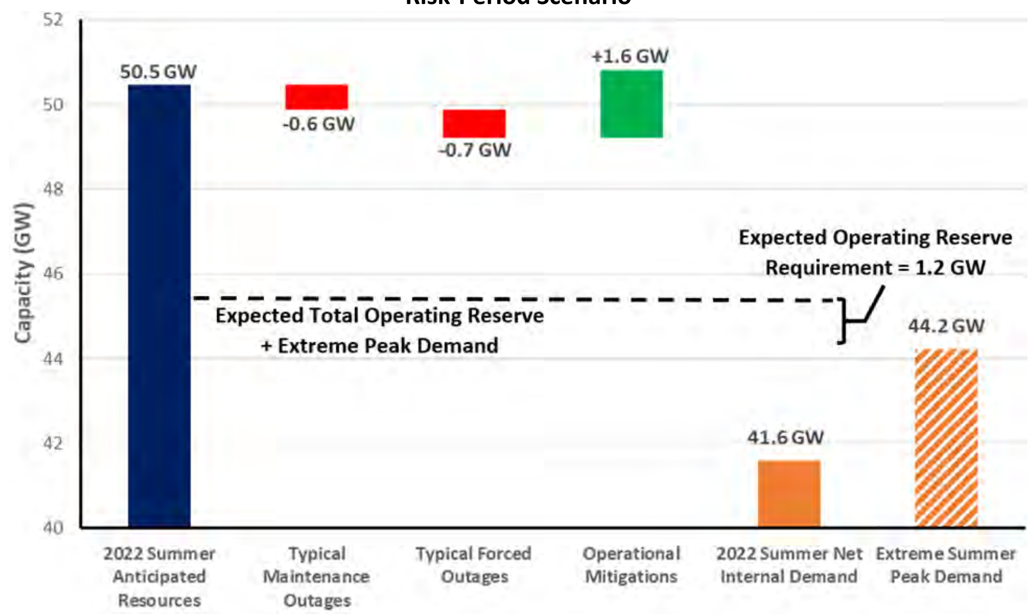
Risk Scenario Summary

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

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.6 GW based on operational/emergency procedures

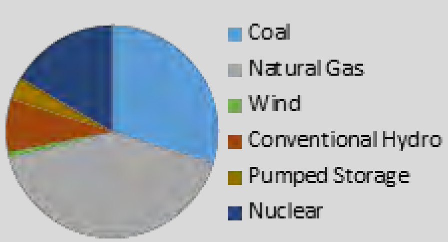
SERC-Central

SERC-Central is a summer peaking assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee, 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 Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



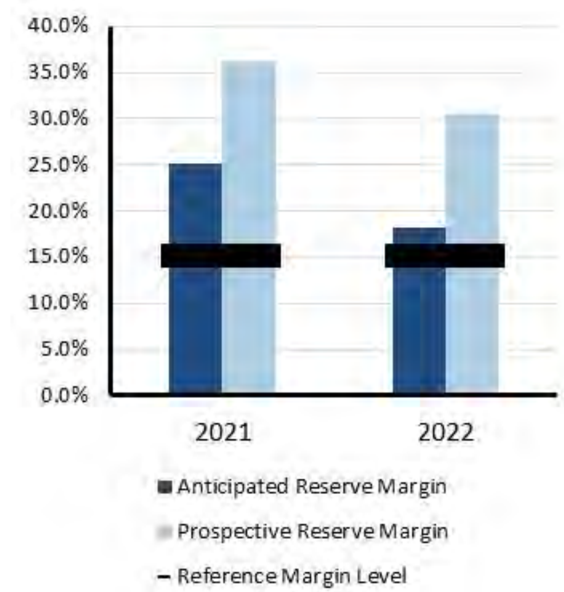
Highlights

- Entities in SERC-Central continue to work collaboratively to ensure reliability for its area within SERC and to promote reliability and adequacy.
- Entities in SERC-Central continue to participate actively in the SERC Near-Term and Long-Term Working Groups, among others, in order to identify and address emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities in SERC-Central have not identified any potential reliability issues for the upcoming summer season.
- Entities anticipate having adequate system capacity for the upcoming season and are equipped to address unexpected, short-term issues leveraging its diverse generation portfolio and spot purchases from the power markets when necessary.
- Probabilistic analysis performed for SERC-Central indicates minimal risk for resource shortfall.

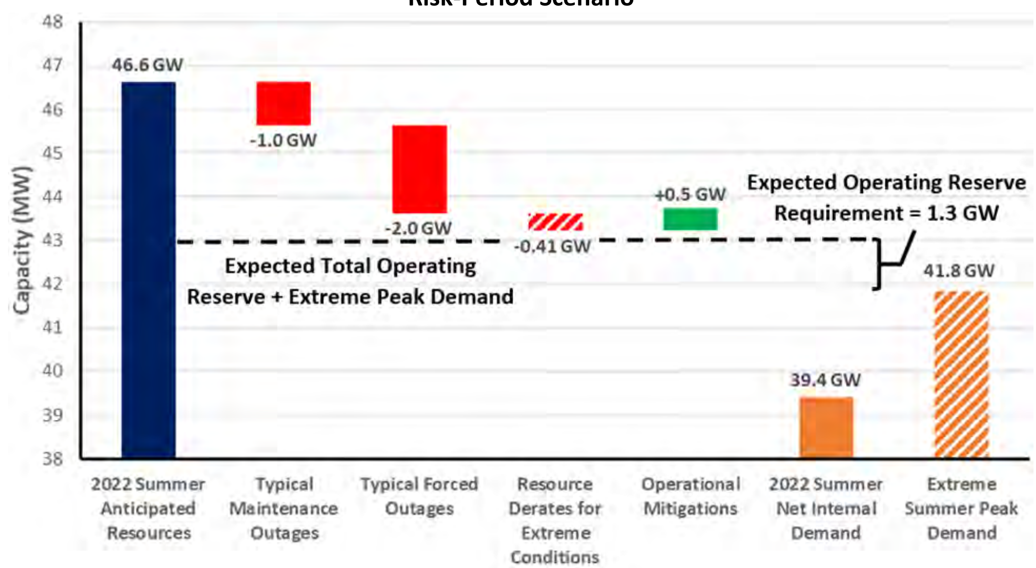
Risk Scenario Summary

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

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 0.5 GW based on operational/emergency procedures

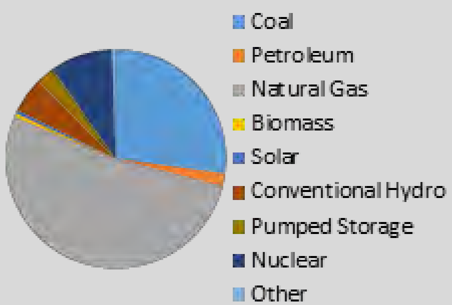
SERC-Southeast

SERC-Southeast is a summer peaking assessment area within the SERC Regional Entiey. 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 Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



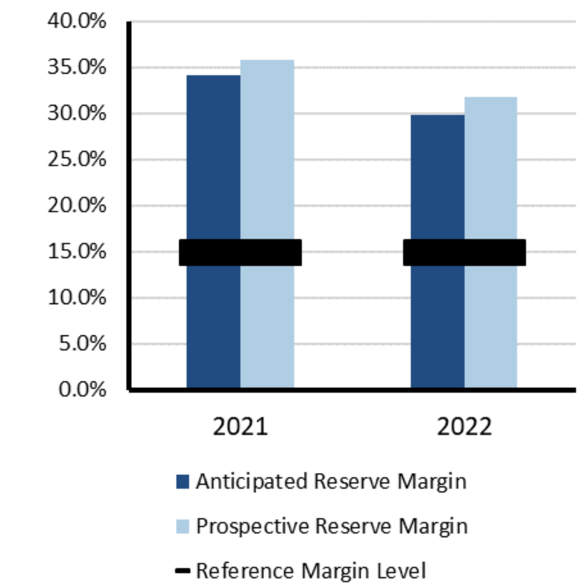
Highlights

- Entities in SERC-Southeast have not identified any emerging reliability issues for the upcoming summer that will impact resource adequacy. The available system capacity for the upcoming summer meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm natural gas contracts, and power purchases.
- Entities in SERC-Southeast continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Probabilistic analysis performed for SERC-Southeast shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices are negligible for SERC-Southeast throughout the summer.

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

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.5 GW based on operational/ emergency procedures

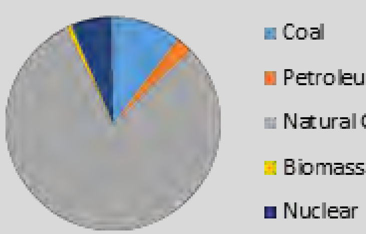
SERC-Florida Peninsula

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

SERC is one of the six 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 Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



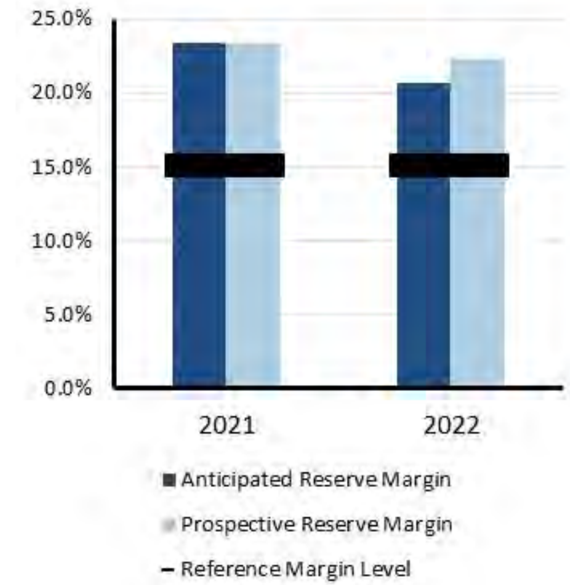
Highlights

- Entities in SERC-Florida Peninsula have not identified any emerging reliability issues or operational concerns for the upcoming summer.
- Entities in SERC-Florida Peninsula continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts to transmission and resource adequacy along with transfer capability.
- Entities within the Florida Peninsula area have reported no operational challenges for the upcoming summer based on current expected system conditions. The BES within the Florida Peninsula is expected to perform reliably for the anticipated 2022 summer season.
- SERC Probabilistic analysis performed for SERC-Florida Peninsula shows there is low risk for resource shortfall for the summer. Load loss and unserved energy indices for SERC-Florida Peninsula are spread across the summer months and remain relatively low (LOLH < 0.03 and EUE < 18 MWH).

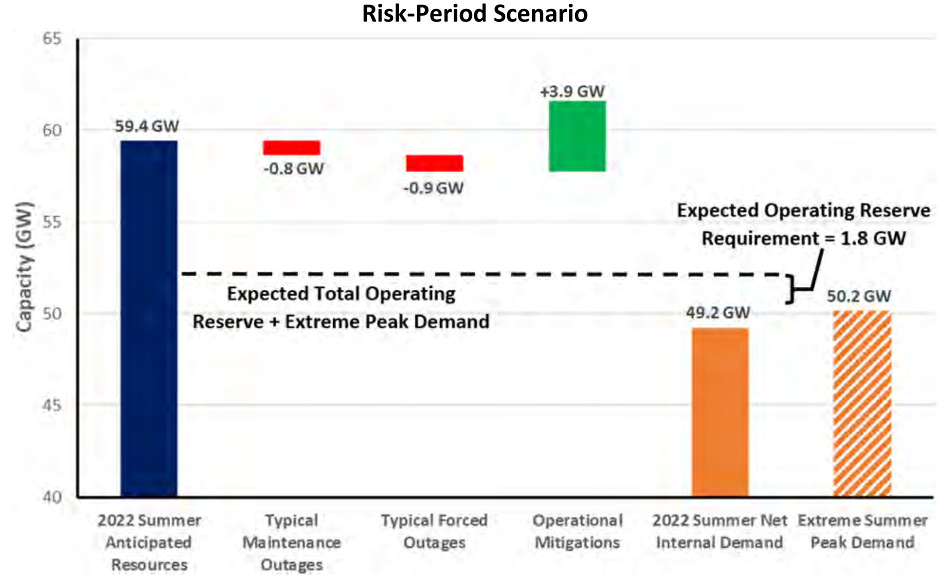
Risk Scenario Summary

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

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

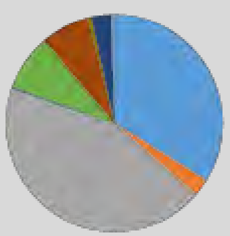
Operational Mitigations: A total of 3.9 GW based on operational/ emergency procedures

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 Fuel Mix



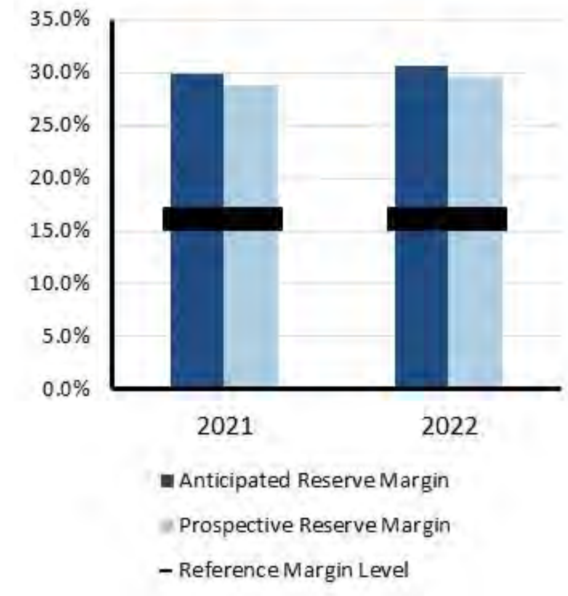
Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2022 summer season.
- The current planning reserve margin should minimize risks of BA capacity deficiencies for summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- There are concerns that drought conditions will impact the Missouri River and other water sources used by generation resources that rely on once-through cooling processes.
- Using current operational processes and procedures, SPP will continue to assess the needs for the 2022 summer season and will adjust as needed to ensure that real time reliability is maintained throughout the summer.

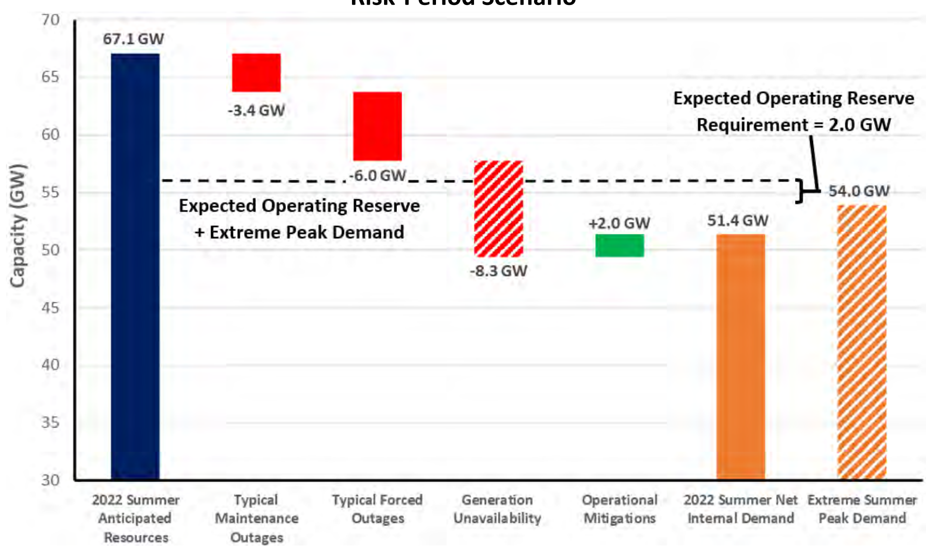
Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding 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 extreme demand is a 5% increase from net internal demand

Maintenance & Forced Outages: Calculated from SPP's generator assessment process

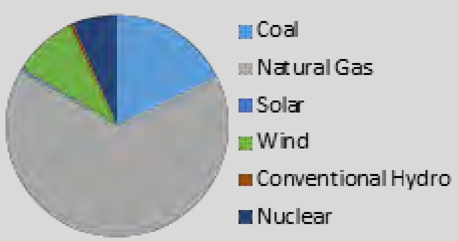
Generation Unavailability: Risk from higher outages to protect against 99.5th percentile of historical coincident generation

Operational Mitigations: A total of 2 GW of behind the meter generation and demand response to be deployed in the event of an emergency alert

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 Regional Entity that covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,000 generation units, and serves more than 26 million customers. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for the ERCOT Regional Entity.

On-Peak Fuel Mix



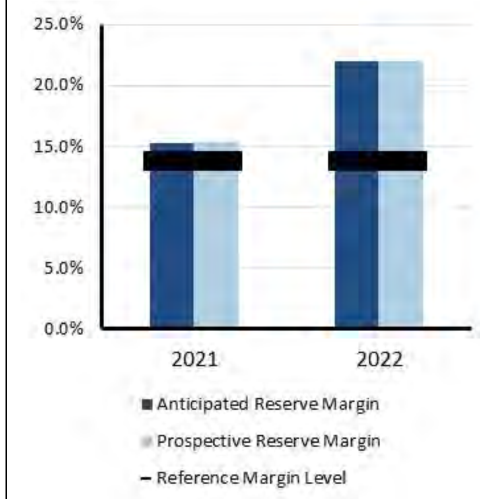
Highlights

- The amount of renewable installed capacity expected to be available during upcoming summer peak demand hours is higher by about 4,100 MW relative to the amount reported in last year's SRA.
- Most of ERCOT is experiencing severe drought conditions, setting the stage for a hotter-than-normal summer.
- Transmission expansion projects in development to add resources or address system performance are being closely monitored for delays or cancellations. Occurrences may contribute to localized reliability concerns.
- On May 9, 2021, a single-line-to-ground fault occurred at a combined-cycle power plant near Odessa, Texas. The fault impacted several solar and wind plants. In response to the NERC report on the disturbance event, ERCOT established an Inverter-based Resource Task Force to facilitate assessment of recommendations to address IBR issues identified in the report.
- An emerging challenge for transmission planning and system operations is the interest in developing new cryptocurrency mining facilities in ERCOT. ERCOT and its stakeholders have recently formed a task force to address the issues associated with these large flexible loads.
- ERCOT's Summer 2022 probabilistic assessment indicates a low risk (6% probability) of declaring a Level 1 Energy Emergency Alert (EEA1) during the expected daily peak load hour. The EEA1 risk is slightly higher from 6:00–8:00 p.m. Central time with the highest-risk hour being 7:00 p.m. This shifting of capacity scarcity risk to later hours is due to the large increase in solar capacity over the last two years. Nevertheless, the overall daily risk is lower than for the Summer 2021 model simulation. For example, the EEA1 peak load hour risk for Summer 2021 was higher at 12%.

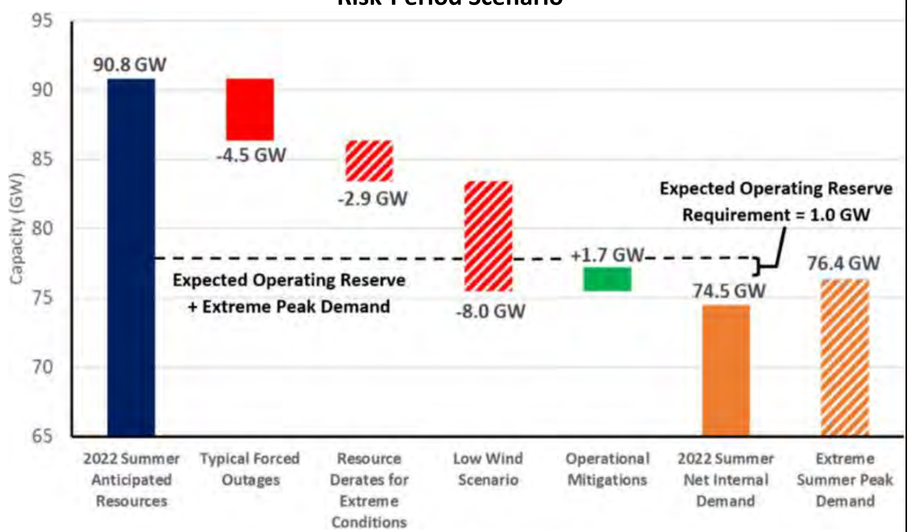
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ interruptible load programs and additional operating mitigations reflected in the scenario. Load shedding 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 extreme demand represents 90^{th} percentile of forecasted summer peaks from 2006–2020

Forced Outages: Based on the historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Extreme Derates: Based on the 95^{th} percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

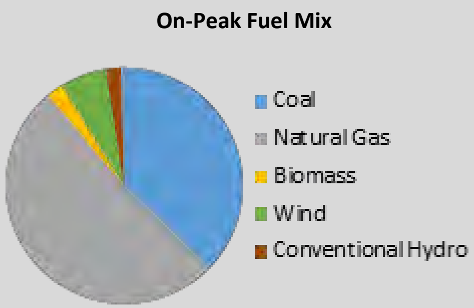
Operational Mitigations: Additional capacity from switchable generation and additional imports

WECC-NWPP-AB

WECC-NWPP-AB (Alberta) is an assessment area in the WECC Regional Entity 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 Regional Entity.

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.



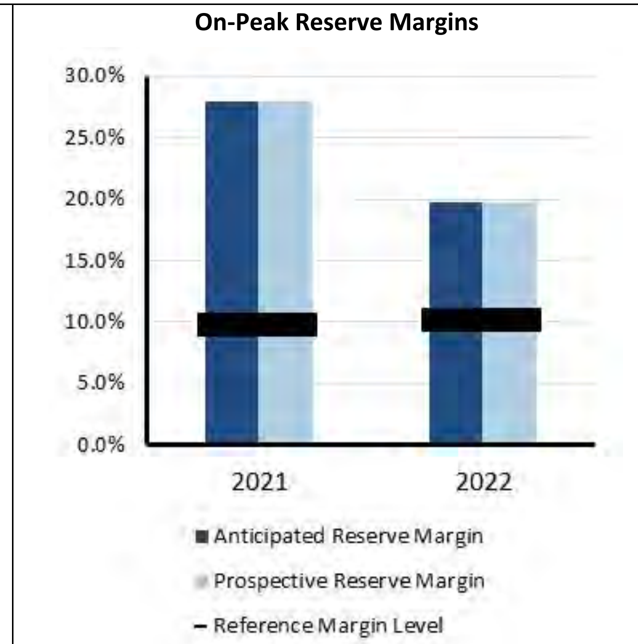
Highlights

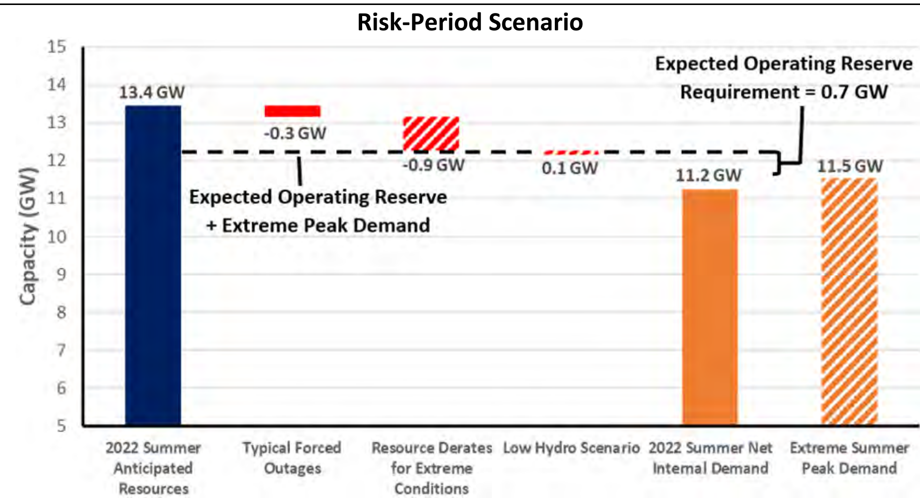
- There are potential natural gas supply-side tightening concerns.
- Reserve margins are tighter but still expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-AB assessment area had negligible LOLH and EUE.

  On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a one-in-ten probability at the 90th percentile, and with either one of the combination of derates on their own or any two in combination, Alberta is expected to have sufficient resource availability to meet demand and cover reserves. However, if all derate conditions were combined concurrently, Alberta would likely need to seek external assistance for imports.

Risk Scenario Summary

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

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

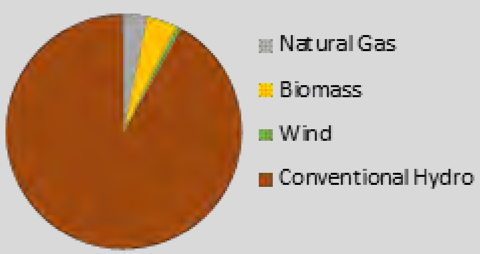
WECC-NWPP-BC

WECC-NWPP-BC (British Columbia) is an assessment area in the WECC Regional Entity 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 Regional Entity.

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



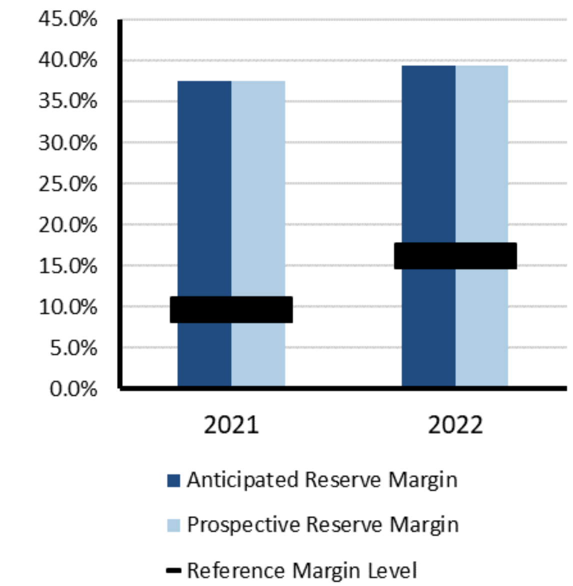
Highlights

- Planned resources in Tier 1 have moved into existing certain.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-BC assessment area had negligible LOLH and EUE.
- On the peak risk hour at 6:00 p.m. local time, under a summer peak defined as a 1-in-10 probability at the 90th percentile, and with any combination of derates other than hydro, BC is expected to have sufficient resource availability to meet demand and cover reserves. However, if a 1-in-10 probability at the 10th percentile of hydro conditions was to occur, BC would need to locate external assistance for imports. Summer 2022 hydro availability in BC is not expected to fall that low despite continued mega-drought conditions across much of the West.

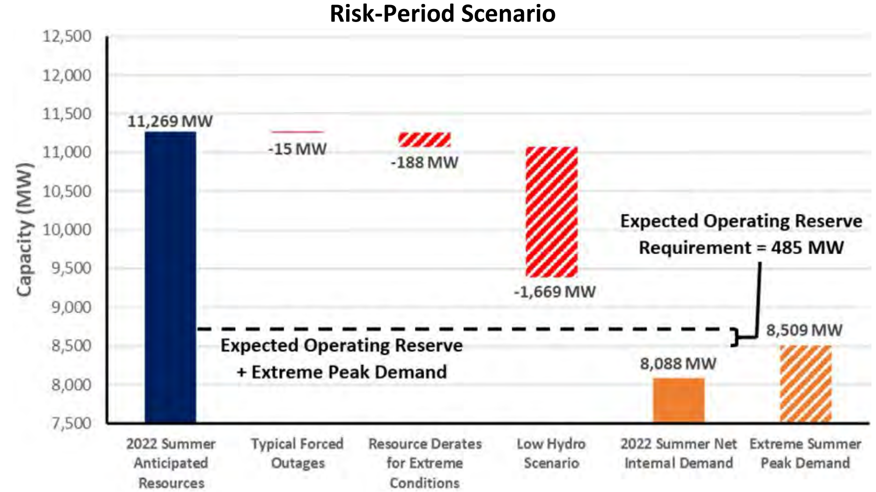
Risk Scenario Summary

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 (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

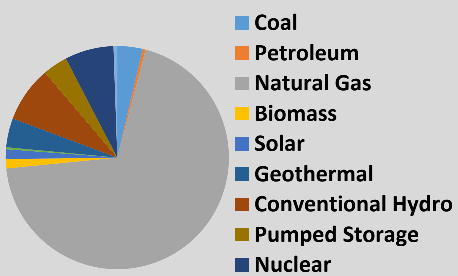
WECC-CA / MX

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

WECC is responsible for coordinating and promoting BES reliability 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 Regional Entity.

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.

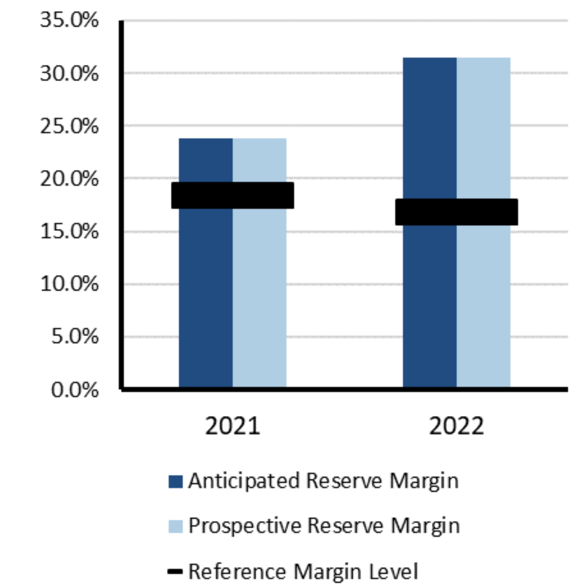
On-Peak Fuel Mix



Highlights

- California ISO is procuring resources to improve reliability risks.
- Localized short-term operational issues may occur due to wildfires, droughts, and/or supply chain issues.
- As cooling degree days continue to rise across the Western Interconnection, there is a risk that is higher than the historical average of prolonged heatwave events
- Based on a WECC probabilistic assessment, the California portion of the assessment area is projected to have an LOLH of 1.0 hours and an EUE of 4 MWh. The Mexico portion is projected to have an LOLH of 10.0 hours and an EUE of 100 MWh.
- On the peak risk hour at 8:00 p.m. local time, there is an under 1-in-10 summer peak probability at the 90th percentile, including firm transfers. The CA/MX area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; CA/MX will need to locate additional external assistance for imports.

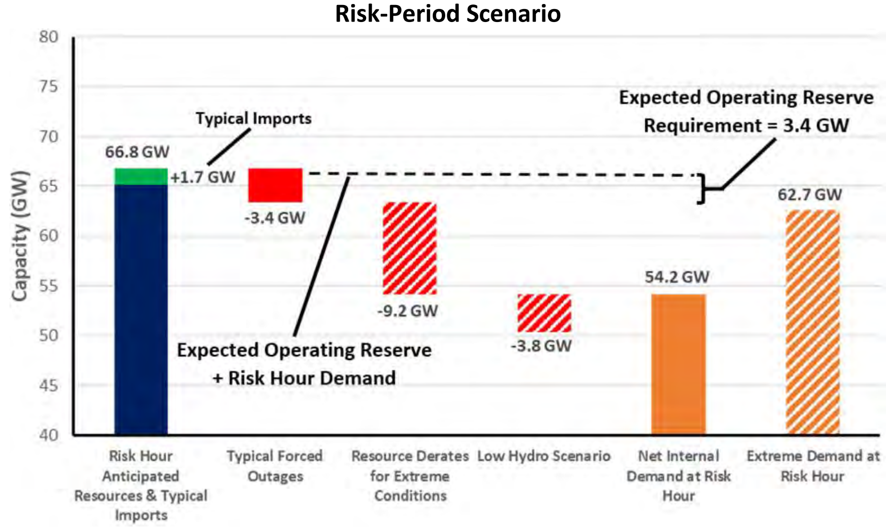
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding 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 8:00 p.m. local time as solar PV output is diminished and demand remains high

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

Forced Outages: Estimated using market forced outage model

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

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

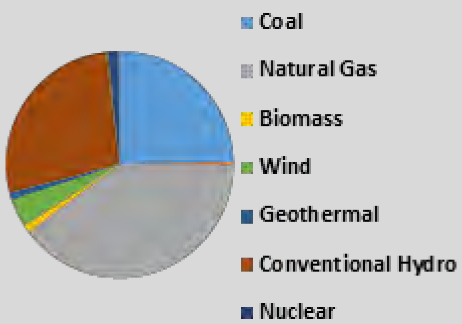
WECC-NWPP-US

WECC-NWPP-US (Northwest Power Pool) is an assessment area in the WECC Regional Entity. 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 Regional Entity.

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



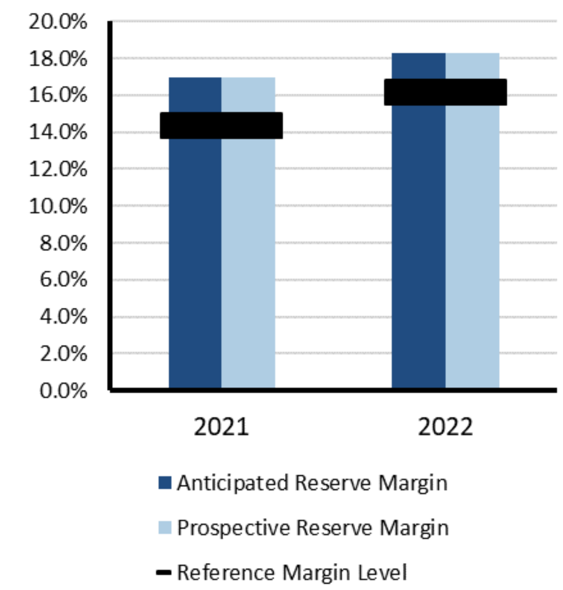
Highlights

- Potential drought conditions remain a concern.
- Reserve margins are up across the board and adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-US assessment area had negligible LOLH and EUE.
- On the peak risk hour at 7:00 p.m., local time and under a summer peak defined as a 1-in-10 probability, including firm transfers, the WECC-NWPP-US area is not expected to have sufficient resource availability to meet demand and cover reserves under any of the scenarios on their own, including typical forced outages; WECC-NWPP-US will need to locate additional external assistance for imports.

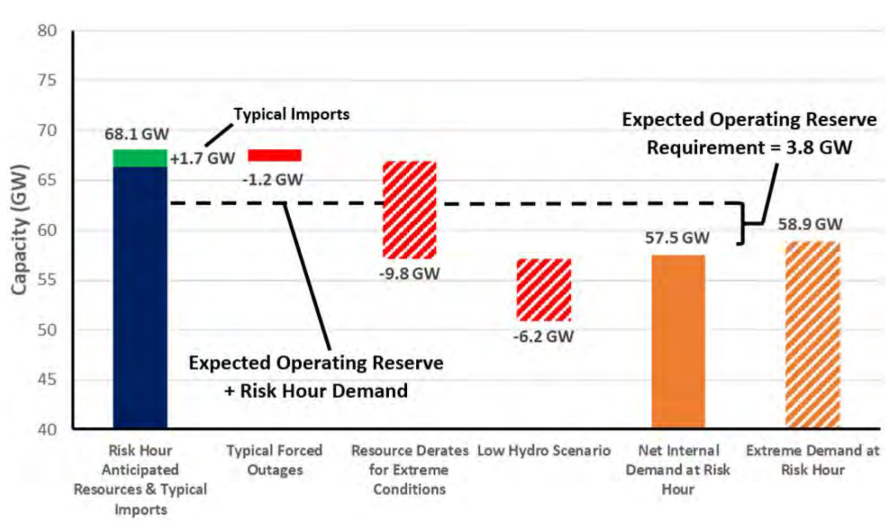
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding 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 7:00 p.m. local time as solar PV output is diminished and demand remains high

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

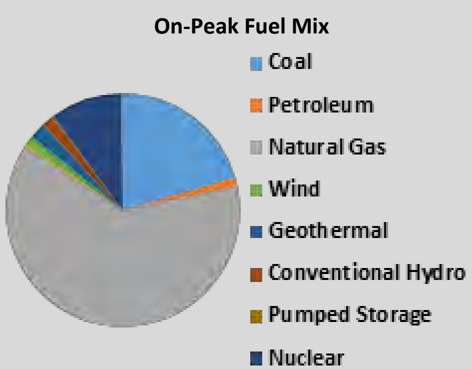
Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

WECC-SRSG

WECC-SRSG (Southwest Reserve Sharing Group) is an assessment area in the WECC Regional Entity. 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 Regional Entity.

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.

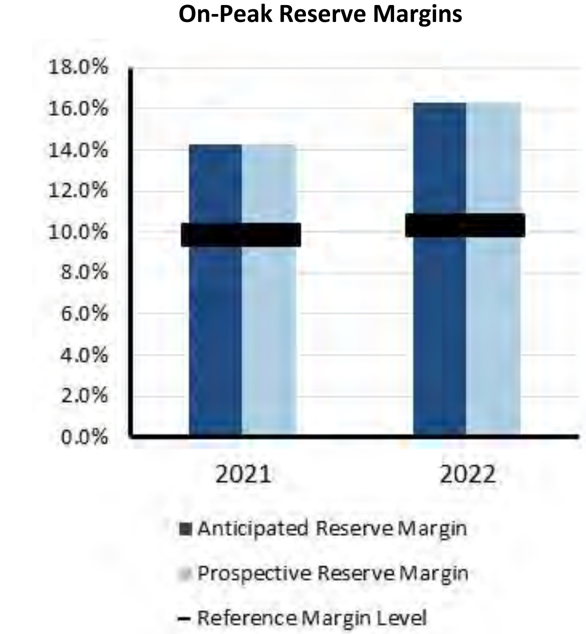


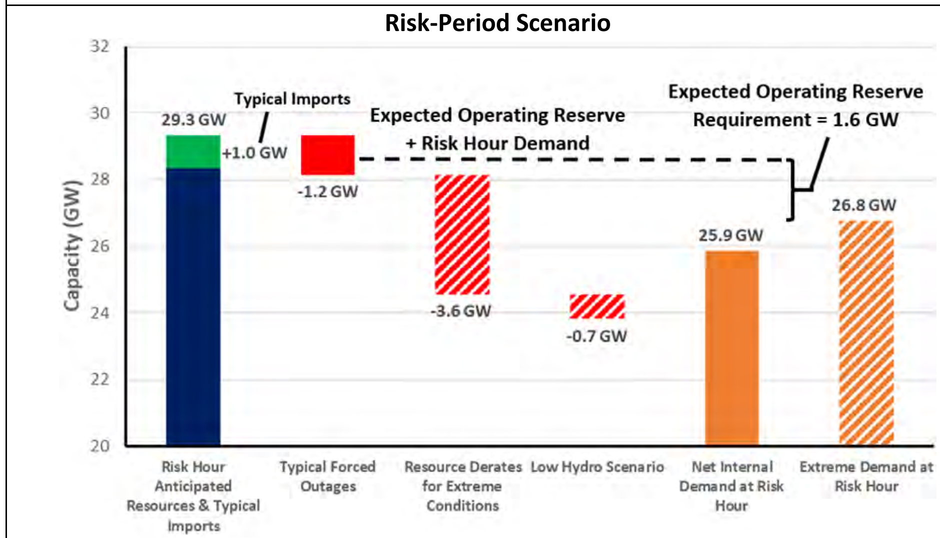
Highlights

- Drought and supply chain issues are the main reliability concerns. Many solar developers are indicating to utilities that they will not be able to meet expected commission dates under executed and approved power purchase agreements, including at least 120 MW of PV planned for the 2022 summer.
- Reserve margins are expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-SRSG assessment area had negligible LOLH and EUE.
- On the peak risk hour is at 7:00 p.m., local time, under a summer peak defined as a 1-in-10 probability, and with either one of the derates on their own, SRSG is not expected to have sufficient resource availability to meet demand and cover reserves; SRSG will likely need to locate additional external assistance for imports.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding 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 7:00 p.m. local time as solar PV output is diminished and demand remains high

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

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 2022 summer 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[7] or total internal demand for the summer and winter of each year.[8]
• Total internal demand projections are based on normal weather (50/50 distribution[9]) and are provided on a coincident[10] 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.

[7] *Glossary of Terms* used in NERC Reliability Standards
[8] The summer season represents June–September and the winter season represents December–February.
[9] 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.
[10] 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 summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

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, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand.

Resource Adequacy

The 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.[11] 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 2022 summer as shown in **Figure 9**.

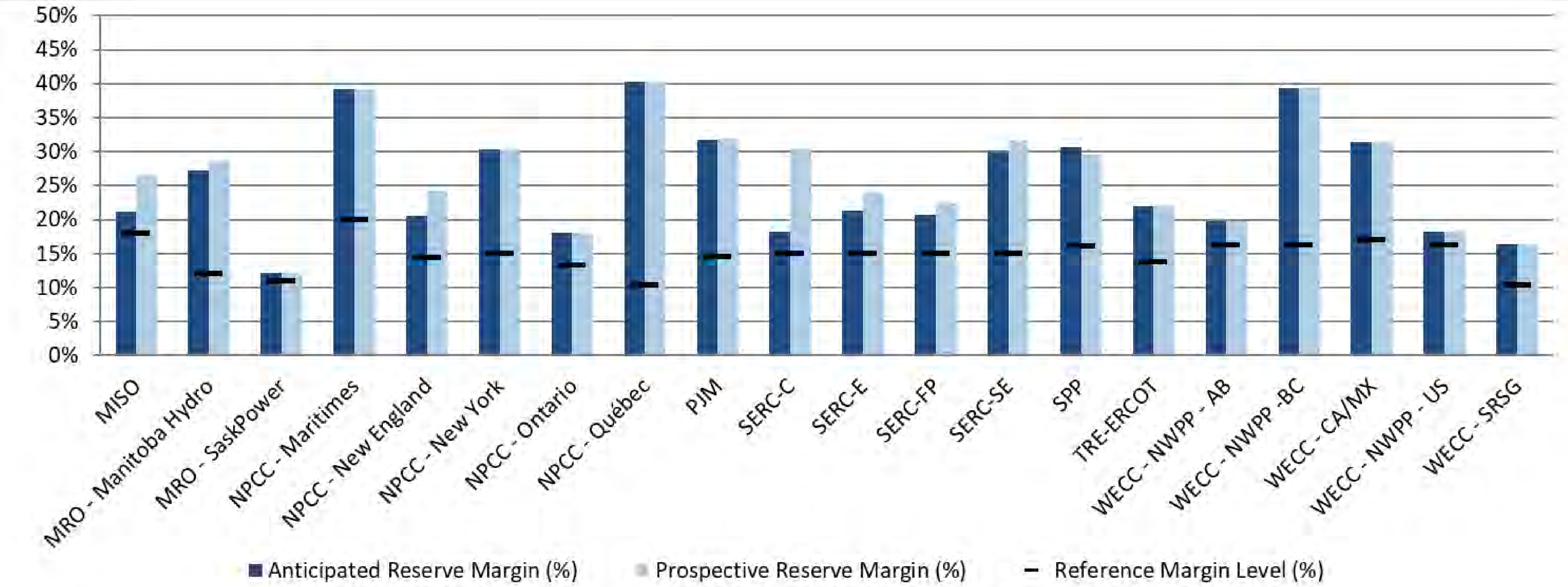
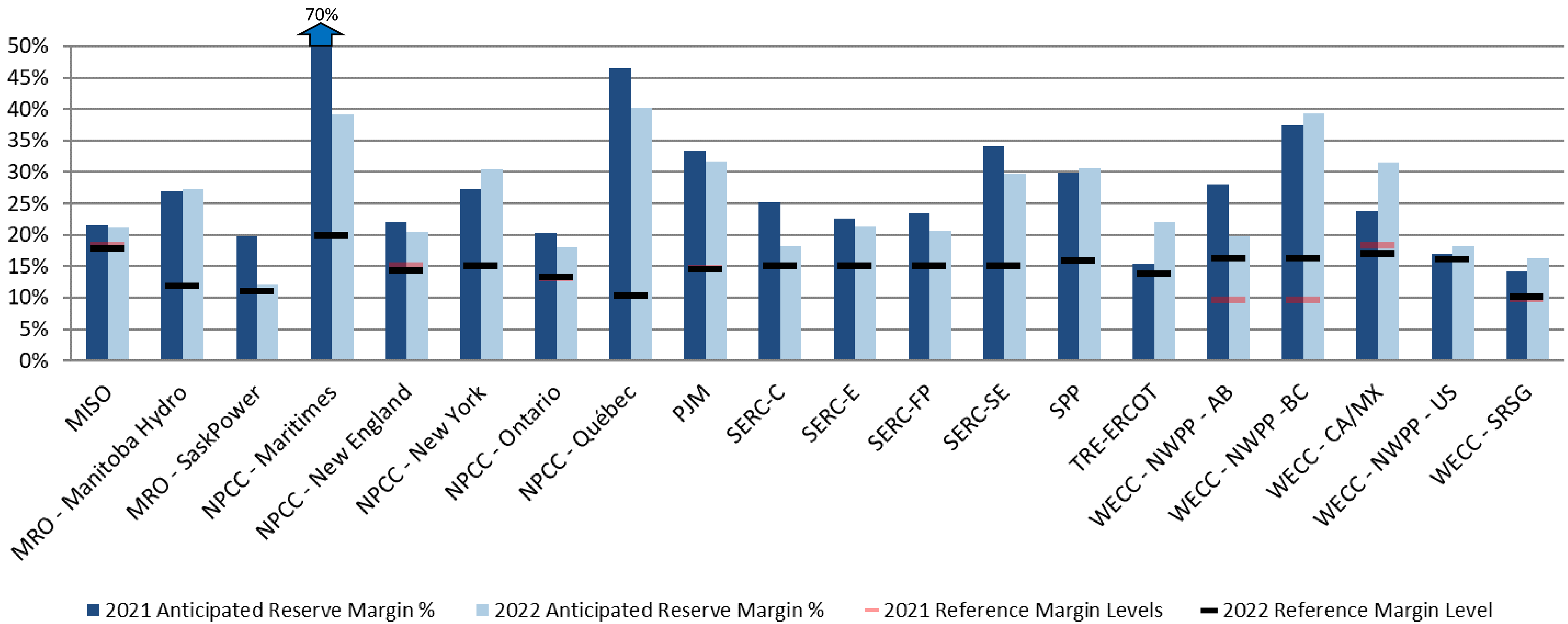


Figure 9: Summer 2022 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[11] 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 2021 summer to the 2022 summer. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB have noticeable reductions in anticipated resources with MRO-SaskPower close to falling below its Reference Margin Level for the 2022 summer. MRO-SaskPower will rely on demand response and transfers from neighbors during a higher load scenario to avoid load interruption. The lower Anticipated Reserve Margins for NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB do not present reliability concerns on peak for this upcoming summer. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.



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

Figure 10: Summer 2021 and Summer 2022 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in Figure 11.[12] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

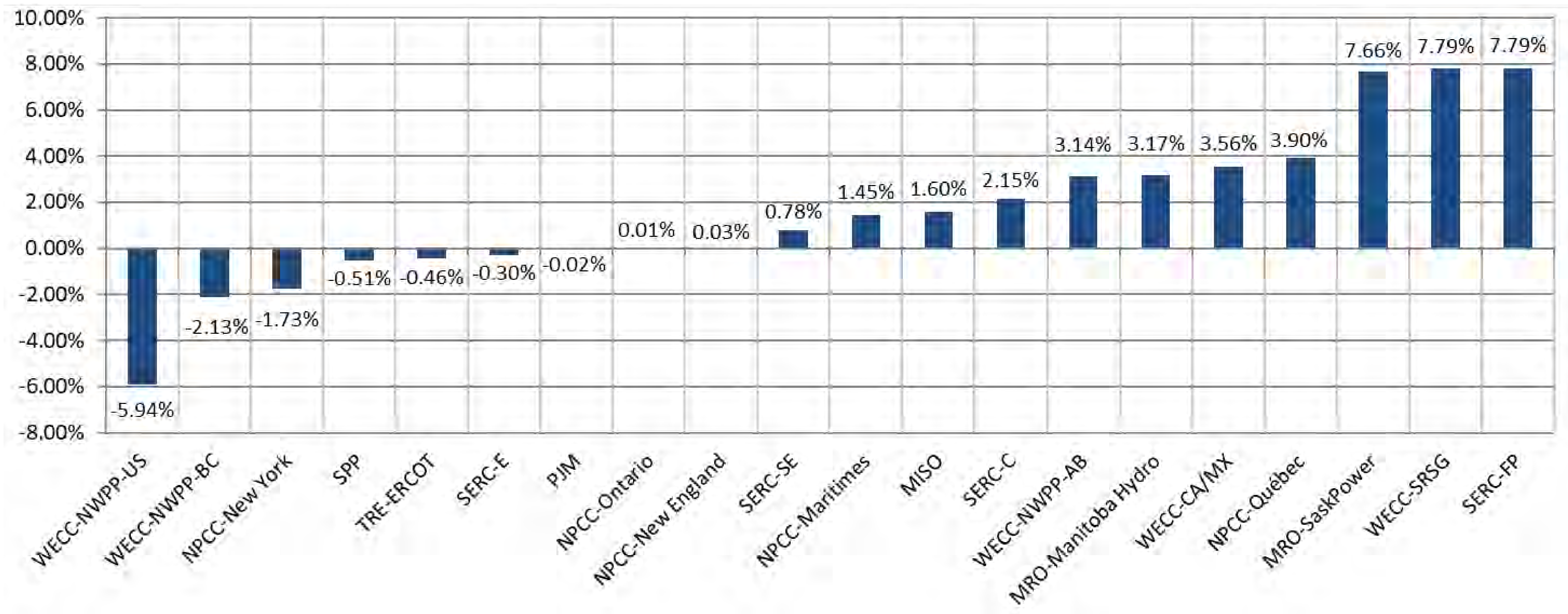


Figure 11: Change in Net Internal Demand: Summer 2021 Forecast Compared to Summer 2022 Forecast

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

Demand and Resource Tables

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

MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	122,398	124,506	1.7%
Demand Response: Available	6,038	6,287	4.1%
Net Internal Demand	116,360	118,220	1.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	138,464	141,844	2.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,979	1,353	-54.6%
Anticipated Resources	141,443	143,197	1.2%
Existing-Other Capacity	633	669	5.7%
Prospective Resources	146,586	149,756	2.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	21.6%	21.1%	-0.5
Prospective Reserve Margin	26.0%	26.7%	0.7
Reference Margin Level	18.3%	17.9%	-0.4

MRO-Manitoba Hydro Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	2,965	3,059	3.2%
Demand Response: Available	0	0	-
Net Internal Demand	2,965	3,059	3.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	5,173	5,523	6.8%
Tier 1 Planned Capacity	186	186	0.0%
Net Firm Capacity Transfers	-1,596	-1,816	13.8%
Anticipated Resources	3,763	3,893	3.4%
Existing-Other Capacity	37	44	18.8%
Prospective Resources	3,800	3,937	3.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	26.9%	27.3%	0.4
Prospective Reserve Margin	28.2%	28.7%	0.5
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,400	3,656	7.5%
Demand Response: Available	60	60	0.0%
Net Internal Demand	3,340	3,596	7.7%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	3,863	3,743	-3.1%
Tier 1 Planned Capacity	13.5	0	-100.0%
Net Firm Capacity Transfers	125	290	132.0%
Anticipated Resources	4,002	4,033	0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,002	4,033	0.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	19.8%	12.2%	-7.6
Prospective Reserve Margin	19.8%	12.2%	-7.6
Reference Margin Level	11.0%	11.0%	0.0

NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021 SRA	2022 SRA	2021 vs. 2022 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,479	3,475	-0.1%
Demand Response: Available	305	255	-16.4%
Net Internal Demand	3,174	3,220	1.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	5,448	4,419	-18.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-57	64	-212.3%
Anticipated Resources	5,391	4,483	-16.8%
Existing-Other Capacity	0	0	-
Prospective Resources	5,391	4,483	-16.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	69.8%	39.2%	-30.6
Prospective Reserve Margin	69.8%	39.2%	-30.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,244	25,300	0.2%
Demand Response: Available	434	483	11.3%
Net Internal Demand	24,810	24,817	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,065	28,626	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,208	1,292	7.0%
Anticipated Resources	30,273	29,918	-1.2%
Existing-Other Capacity	1115	911	-18.3%
Prospective Resources	31,388	30,829	-1.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	20.6%	-1.4
Prospective Reserve Margin	26.5%	24.2%	-2.3
Reference Margin Level	15.0%	14.3%	-0.7

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,500	22,546	0.2%
Demand Response: Available	621	666	7.2%
Net Internal Demand	21,879	21,880	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,217	25,648	-2.2%
Tier 1 Planned Capacity	22	24	10.9%
Net Firm Capacity Transfers	80	150	87.5%
Anticipated Resources	26,319	25,822	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	26,319	25,822	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.3%	18.0%	-2.3
Prospective Reserve Margin	20.3%	18.0%	-2.3
Reference Margin Level	13.2%	13.3%	0.1

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	32,333	31,765	-1.8%
Demand Response: Available	1,199	1,170	-2.4%
Net Internal Demand	31,134	30,595	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,805	37,431	-1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,816	2,465	35.7%
Anticipated Resources	39,621	39,896	0.7%
Existing-Other Capacity	0	0	-
Prospective Resources	39,621	39,896	0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.3%	30.4%	3.1
Prospective Reserve Margin	27.3%	30.4%	3.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,436	22,271	3.9%
Demand Response: Available	0	0	-
Net Internal Demand	21,436	22,271	3.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,380	33,542	0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,995	-2,304	15.5%
Anticipated Resources	31,385	31,238	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	31,385	31,238	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.4%	40.3%	-6.1
Prospective Reserve Margin	46.4%	40.3%	-6.1
Reference Margin Level	10.4%	10.3%	-0.1

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	149,224	148,938	-0.2%
Demand Response: Available	8,779	8,527	-2.9%
Net Internal Demand	140,445	140,411	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,572	184,837	0.7%
Tier 1 Planned Capacity	2400	10	-99.6%
Net Firm Capacity Transfers	1,460	124	-91.5%
Anticipated Resources	187,431	184,971	-1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	188,891	185,095	-2.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	31.7%	-1.8
Prospective Reserve Margin	34.5%	31.8%	-2.7
Reference Margin Level	14.7%	14.9%	0.2

SERC-East Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,680	42,883	0.5%
Demand Response: Available	970	1,298	33.8%
Net Internal Demand	41,710	41,585	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,539	49,380	-2.3%
Tier 1 Planned Capacity	0	486	-
Net Firm Capacity Transfers	562	612	8.9%
Anticipated Resources	51,101	50,478	-1.2%
Existing-Other Capacity	766	1,097	43.2%
Prospective Resources	51,867	51,575	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.5%	21.4%	-1.1
Prospective Reserve Margin	24.4%	24.0%	-0.4
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,341	41,267	2.3%
Demand Response: Available	1,744	1,841	5.6%
Net Internal Demand	38,597	39,426	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,987	47,424	-1.2%
Tier 1 Planned Capacity	154	0	-100.0%
Net Firm Capacity Transfers	172	-795	-561.6%
Anticipated Resources	48,314	46,629	-3.5%
Existing-Other Capacity	4290	4,808	12.1%
Prospective Resources	52,604	51,437	-2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.2%	18.3%	-6.9
Prospective Reserve Margin	36.3%	30.5%	-5.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,710	52,172	7.1%
Demand Response: Available	3,030	2,932	-3.2%
Net Internal Demand	45,680	49,240	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,351	56,571	2.2%
Tier 1 Planned Capacity	0	2,540	-
Net Firm Capacity Transfers	1,007	300	-70.2%
Anticipated Resources	56,358	59,411	5.4%
Existing-Other Capacity	0	847	-
Prospective Resources	56,358	60,258	6.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.4%	20.7%	-2.7
Prospective Reserve Margin	23.4%	22.4%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,631	47,258	1.3%
Demand Response: Available	1,671	1,946	16.5%
Net Internal Demand	44,960	45,312	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,263	59,828	-2.3%
Tier 1 Planned Capacity	142	1,514	964.9%
Net Firm Capacity Transfers	-1,115	-2,524	126.4%
Anticipated Resources	60,290	58,818	-2.4%
Existing-Other Capacity	783	859	9.7%
Prospective Resources	61,073	59,677	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	34.1%	29.8%	-4.3
Prospective Reserve Margin	35.8%	31.7%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,249	52,040	-0.4%
Demand Response: Available	606	658	8.6%
Net Internal Demand	51,643	51,382	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	66,600	67,245	1.0%
Tier 1 Planned Capacity	300	0	-100.0%
Net Firm Capacity Transfers	186	-144	-177.6%
Anticipated Resources	67,086	67,101	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	66,539	66,554	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.9%	30.6%	0.7
Prospective Reserve Margin	28.8%	29.5%	0.7
Reference Margin Level	16.0%	16.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	77,144	77,317	0.2%
Demand Response: Available	2,341	2,856	22.0%
Net Internal Demand	74,803	74,461	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	80,569	89,603	11.2%
Tier 1 Planned Capacity	5489	1,199	-78.2%
Net Firm Capacity Transfers	210	20	-90.5%
Anticipated Resources	86,268	90,822	5.3%
Existing-Other Capacity	0	0	-
Prospective Resources	86,296	90,850	5.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.3%	22.0%	6.7
Prospective Reserve Margin	15.4%	22.0%	6.6
Reference Margin Level	13.75%	13.75%	0.0

WECC-NWPP-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,886	11,228	3.1%
Demand Response: Available	0	0	-
Net Internal Demand	10,886	11,228	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	12,205	11,926	-2.3%
Tier 1 Planned Capacity	1723	1,082	-37.2%
Net Firm Capacity Transfers	0	437	-
Anticipated Resources	13,928	13,445	-3.5%
Existing-Other Capacity	0	0	-
Prospective Resources	13,928	13,445	-3.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.9%	19.7%	-8.2
Prospective Reserve Margin	27.9%	19.7%	-8.2
Reference Margin Level	9.7%	10.1%	0.4

WECC-NWPP-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,264	8,088	-2.1%
Demand Response: Available	0	0	-
Net Internal Demand	8,264	8,088	-2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,178	11,266	0.8%
Tier 1 Planned Capacity	185	3	-98.4%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,363	11,269	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	11,363	11,269	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.5%	39.3%	1.8
Prospective Reserve Margin	37.5%	39.3%	1.8
Reference Margin Level	9.7%	16.3%	6.5

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	55,409	57,269	3.4%
Demand Response: Available	922	844	-8.4%
Net Internal Demand	54,487	56,425	3.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,396	70,791	11.7%
Tier 1 Planned Capacity	3358	3,381	0.7%
Net Firm Capacity Transfers	686	0	-100.0%
Anticipated Resources	67,440	74,172	10.0%
Existing-Other Capacity	0	0	-
Prospective Resources	67,440	74,172	10.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.8%	31.5%	7.7
Prospective Reserve Margin	23.8%	31.5%	7.7
Reference Margin Level	18.4%	16.9%	-1.5

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,751	26,720	8.0%
Demand Response: Available	332	399	20.0%
Net Internal Demand	24,419	26,321	7.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,850	28,249	5.2%
Tier 1 Planned Capacity	188	1,369	628.2%
Net Firm Capacity Transfers	866	1,002	15.7%
Anticipated Resources	27,904	30,620	9.7%
Existing-Other Capacity	0	0	-
Prospective Resources	27,904	30,620	9.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.3%	16.3%	2.0
Prospective Reserve Margin	14.3%	16.3%	2.0
Reference Margin Level	9.8%	10.2%	0.4

WECC-NWPP-US Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021 SRA**	**2022 SRA**	**2021 vs. 2022 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	67,117	63,214	-5.8%
Demand Response: Available	1,087	1,104	1.5%
Net Internal Demand	66,030	62,110	-5.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,069	70,154	0.1%
Tier 1 Planned Capacity	1,002	798	-20.4%
Net Firm Capacity Transfers	6,139	2,517	-59.0%
Anticipated Resources	77,210	73,469	-4.8%
Existing-Other Capacity	0	0	-
Prospective Resources	77,210	73,469	-4.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.9%	18.3%	1.4
Prospective Reserve Margin	16.9%	18.3%	1.4
Reference Margin Level	14.3%	16.1%	1.8

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The table below shows the capacity contribution of existing wind and solar resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (i.e., U.S. assessment areas in WECC), lower contributions of solar resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar	Expected Solar	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	28,893	4,478	16%	2,441	1,221	50%	2,440	2,361	97%
MRO-Manitoba Hydro	259	41	16%	-	-	0%	5,917	5,255	89%
MRO-SaskPower	628	88	14%	-	-	0%	864	784	91%
NPCC-Maritimes	1,212	326	27%	2	-	0%	1,315	1,183	90%
NPCC-New England	1,421	201	14%	2,638	773	29%	4,059	2,812	69%
NPCC-New York	2,336	314	13%	76	35	46%	5,949	5,138	86%
NPCC-Ontario	4,943	751	15%	478	66	14%	8,918	4,716	53%
NPCC-Québec	3,820	-	0%	10	-	0%	41,346	32,789	79%
PJM	10,876	1,659	15%	4,852	2,878	64%	3,022	3,022	100%
SERC-Central	964	4	0%	450	287	64%	5,005	3,381	68%
SERC-East	-	-	0%	724	716	99%	3,052	3,002	98%
SERC-Florida Peninsula	-	-	0%	5,246	3,220	61%	-	-	0%
SERC-Southeast	-	-	0%	4,053	3,500	86%	3,242	3,288	101%
SPP	31,325	7,276	23%	306	245	80%	5,456	5,297	97%
Texas RE-ERCOT	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC-AB	3,177	232	7%	1,063	684	64%	894	378	42%
WECC-BC	717	142	20%	2	1	49%	16,378	10,115	62%
WECC-CA/MX	8,946	1,754	20%	19,457	13,634	70%	13,985	7,691	55%
WECC-NWPP-US	19,410	3,312	17%	7,479	4,735	63%	41,705	21,564	52%
WECC-NWPP-SRSG	3,245	516	16%	3,219	2,511	78%	3,532	2,765	78%
EASTERN INTERCONNECTION	82,856	14,425	17%	21,476	13,836	64%	50,846	41,776	82%
QUÉBEC INTERCONNECTION	3,820	-	0%	10	-	0%	41,346	32,789	79%
TEXAS INTERCONNECTION	35,454	9,423	27%	11,515	9,327	81%	571	475	83%
WECC INTERCONNECTION	35,495	5,956	17%	31,220	21,565	69%	76,494	42,513	56%
TOTAL:	157,626	29,804	19%	64,221	44,729	70%	169,257	117,554	69%

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2023 Summer Reliability Assessment

May 2023

[2023 Summer Reliability Assessment Video]

Table of Contents

Preface

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

Reliability | Resilience | Security

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

The North American BPS is made up of six Regional Entities as shown on the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators (TO/TOP) 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 *2023 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise 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 summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment provides an evaluation of generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak net demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC has highlighted in the *2022 Long-Term Reliability Assessment* and other earlier reliability assessments and reports.

The following findings are NERC's and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for the 2023 summer.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load and conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historic high outage rates as well as low wind, solar photovoltaic (PV), or hydro energy conditions:

- **Midcontinent ISO (MISO):** The risk of being unable to meet reserve requirements at peak demand this summer in MISO is lower than in 2022 due to additional firm import commitments and lower peak demand forecast. MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand. Wind generator performance during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system to maintain reliability. MISO can face challenges in meeting above-normal peak demand if wind generator energy output is lower than expected. Furthermore, the need for external (non-firm) supply assistance during more extreme demand levels will depend largely on wind energy output. Results of MISO's capacity auction have not been released at the time of this assessment, and these could change MISO's firm resources for the summer.

- **NPCC-New England:** Anticipated resources in New England are projected to be lower than in 2022 but are expected to remain sufficient for meeting operating reserve requirements at normal peak demand. Operating procedures for obtaining emergency resources or non-firm supplies from neighboring areas are likely to be needed during more extreme demand or low resource conditions.

- **NPCC-Ontario:** Planned nuclear outage for refurbishment have reduced the electricity supply resources serving the province. Additionally, load growth is contributing to a constrained transmission network during high-demand conditions that may not be able to deliver sufficient supply to the Windsor-Essex area in the southwest part of the province. Additional generator outages or extreme demand can lead to reserve shortages and a need to seek non-firm imports. Ontario could potentially see a significant increase in reliance on imports this summer under both normal peak (50/50) and extreme (90/10) demand scenarios.

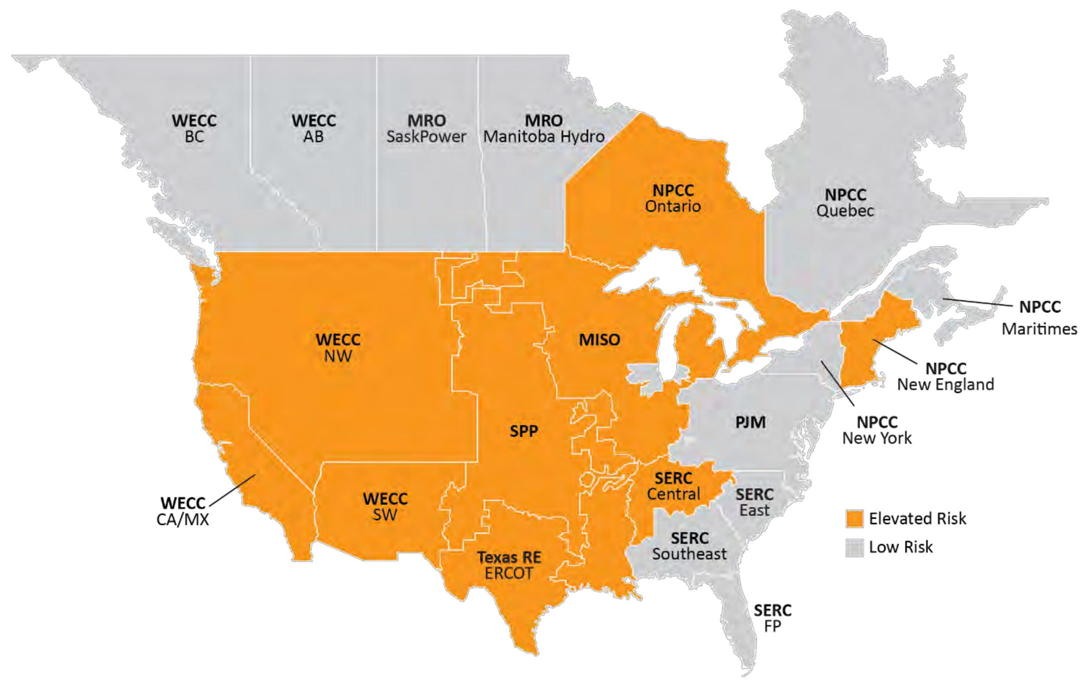
- **SERC-Central**: Compared to the summer of 2022, forecasted peak demand has risen by over 950 MW while growth in anticipated resources has been flat. The assessment area is expected to have sufficient supply for normal peak demand while demand-side management or other operating mitigations can be expected for above-normal demand or high generator-outage conditions.

- **Southwest Power Pool (SPP):** Reserve margins have also fallen in SPP as a result of increasing peak demand and declining anticipated resources. Like MISO, the energy output of SPP's wind generators during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system. SPP can face energy challenges in meeting extreme peak demand or managing periods of thermal or hydro generator outages if wind resource energy output is below normal.

- **Texas (ERCOT):** The area is experiencing strong growth in both resources and forecasted demand. ERCOT added over 4 GW of new solar PV nameplate capacity to the ERCOT grid since 2022. Additionally, load reductions from dispatchable demand response programs have grown by over 18% to total 3,380 MW. ERCOT's peak demand forecast has also risen by 6% as a result of economic growth. Resources are adequate for peak demand of the average summer; however, dispatchable generation may not be sufficient to meet reserves during an extreme heat-wave that is accompanied by low winds.

- **U.S. Western Interconnection:** Resources across the area are sufficient to support normal peak demand. However, wide-area heat events can expose the WECC assessment areas of California/Mexico (CA/MX), Northwest (NW), and Southwest (SW) to risk of energy supply shortfall as each area relies on regional transfers to meet demand at peak and the late afternoon to evening hours when energy output from the area's vast solar PV resources are diminished. Within the Western Interconnection, entities are planning to install over 2 GW of new battery energy storage systems, which can help reduce energy risks from resource variability. Wildfire risks to the transmission network, which often accompany these wide-area heat events, can limit electricity transfers and result in localized load shedding.

All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions. Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions. Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate. Figure 1 below summarizes the risk status for all assessment areas.



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

Figure 1: Summer Reliability Risk Area Summary

Other Reliability Issues

- **Stored supplies of natural gas and coal are at high levels, but industry is monitoring for potential generator fuel delivery risks.** The natural gas supply and infrastructure is vitally important to electric grid reliability, even as renewable generation satisfies more of our energy needs. Fuel supply and delivery infrastructure must be capable of meeting the ramp rates of natural-gas-fired generators as they balance the system when solar generation output declines. Likewise, owners and operators of some coal-fired generators in the U.S. Southeast report challenges in arranging coal replenishment due to mine closures and transport delays. Consequently, some Balancing Authorities (BA) continue to employ coal-conservation measures that began in late 2022 in order to maintain sufficient stocks for peak months.

- **New environmental rules that restrict power plant emissions will limit the operation of coal-fired generators in 23 states, including Nevada, Utah, and several states in the Gulf Coast, mid-Atlantic, and Midwest.** The U.S. Environmental Protection Agency's (EPA) Good Neighbor Plan, finalized on March 15, 2023, ensures that affected states meet the Clean Air Act's "Good Neighbor" requirements by reducing pollution that significantly contributes to problems attaining and maintaining the EPA's health-based air quality standard[1] for ground-level ozone (i.e., smog) in downwind states.[2] Coal and natural-gas-fired generators in states affected by the Good Neighbor Plan will likely meet tighter emissions restrictions primarily by limiting hours of operation in this first year of implementation rather than through adding emissions control equipment. RCs in summer-peaking areas typically are not able to authorize extended outages to upgrade systems during this summer season in order to ensure sufficient resources for high demand. The final rule approved by the EPA includes provisions designed to give grid owners and operators flexibility to help maintain reliability, including allowance-trading mechanisms. Consequently, RCs, BAs, and GOs will need to be vigilant for emissions rule constraints that affect generator dispatchability and the potential need for emission allowance trades or waivers to meet high demand or low resource conditions. State regulators and industry should have protocols in place at the start of summer for managing emergent requests.

- **Low inventories of replacement distribution transformers could slow restoration efforts following hurricanes and severe storms.** The electric industry continues to face a shortage of distribution transformers as a result of production not keeping pace with demand. A survey by the American Public Power Association revealed that many utilities have low levels of emergency stocks that are used for responding to natural disasters and catastrophic events.[3]

[1] This standard is known as the 2015 Ozone National Ambient Air Quality Standards (NAAQS)
[2] https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs#summary

[3] https://www.publicpower.org/periodical/article/appa-survey-members-shows-distribution-transformer-production-not-meeting-demand

Asset sharing programs used by utilities provide visibility and voluntary equipment sharing to maximize resources; however, electricity customers may experience delayed restoration of power following storms as crews must work to obtain new equipment. New efficiency standards for distribution transformers proposed by the U.S. Department of Energy could further exacerbate the transformer supply shortages.[4]

- **Supply chain issues present maintenance and summer preparedness challenges and are delaying some new resource additions.** Difficulties in obtaining sufficient labor, material, and equipment as a result of broad economic factors has affected preseason maintenance of transmission and generation facilities in North America. These supply chain issues have led some owners and operators to delay or cancel maintenance activities that are typically performed to ensure facilities are ready for summer conditions. Additionally, GOs in some areas that were preparing to interconnect new generation are facing delays that will prevent some from being available to meet expected peak summer demand. This includes areas in the U.S. Southeast and the U.S. part of the Western Interconnection (see **Regional Assessments Dashboards** for details). These supply chain issues can exacerbate concerns in elevated risk areas (**Figure 1**) and add challenges to operators across the BPS. Should project delays emerge, affected GOs and TOs must communicate changes to BAs, TOPs, and RCs so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.
- **Winter precipitation is expected to improve the water supply for hydro generation in parts of the U.S. West, but low water levels on major reservoirs remain a concern for electricity generation.** Significant amounts of rainfall and high elevation snow are expected to help replenish reservoirs and maintain river flows that provide energy for most of California's hydroelectric facilities. However, reservoirs at the largest hydro facilities in the U.S. West, including Washington's Grand Coulee Dam and the Hoover Dam on the Arizona-Nevada border, remain at historic low levels, potentially limiting hydroelectric energy output. Power from these plants is used throughout the U.S. Western Interconnection.
- **Unexpected tripping of wind and solar PV resources during grid disturbances continues to be a reliability concern.** NERC has analyzed multiple large-scale disturbances on the BPS that involved widespread loss of inverter-based resources (IBR). In 2021 and 2022, the Texas Interconnection experienced widespread IBR loss events, like those previously observed in the California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California. In 2022, ERCOT required GOs to submit mitigation plans, and corrective measures are being implemented in 2023. In March 2023, NERC issued the *Inverter-Based Resource Performance Issues Alert* to GOs of Bulk Electric System (BES) solar PV generating resources.[5] As a Level 2 alert, it contains recommended actions for GOs of grid-connected solar PV resources, including steps to coordinate protection and controller settings, so that the resources will reliably operate during grid disturbances.
- **Curtailment of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern.** During energy emergencies and periods of transmission system congestion, RCs and BAs may curtail area transfers for various reasons using established procedures and protocols. While the curtailments alleviate an issue in one part of the system, they can contribute to supply shortages or effect local transmission system operations in another area. Two recent extreme temperature events highlight the effect of transfer curtailments on area supply needs during energy emergencies. During the September 2022 wide-area heat dome, a BA in the WECC-SW assessment area declared an energy emergency when the neighboring assessment area, California Independent System Operator (CAISO), curtailed transfers in order to meet the high demand within their own area. During Winter Storm Elliott, firm exports were curtailed from PJM during a period of widespread energy emergencies in the U.S. Eastern Interconnection.

  For the summer of 2023, several areas identified as having capacity or energy risks are relying on imports of electricity supplies. These areas include MISO, NPCC-Ontario, SERC-Central, and the assessment areas in the U.S. Western Interconnection. A wide-area heat event that severely affects regional demand or generator availability presents an added concern in areas that are dependent on imports for managing high electricity demand.
- **In addition to the risk items identified in the Key Findings, resource outages will continue to present challenges in many areas during "near-peak" demand conditions that occur in spring and fall.** Many parts of North America experience elevated temperatures that extend beyond the summer (June–September) months into periods when BPS equipment owners and operators historically scheduled outages for maintenance. Increasingly, BAs are facing resource constrained periods during shoulder months as unseasonable temperatures coincide with generator unavailability. Careful attention to long-term weather forecasts and the potential for unusual heat patterns in the shoulder months is important to inform the need for more conservative outage coordination periods.

[4] https://www.energy.gov/articles/doe-proposes-new-efficiency-standards-distribution-transformers

[5] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2023-03-14-01%20Level%202%20-%20Inverter-Based%20Resource%20Performance%20Issues.pdf

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified previously in the key findings should take the following actions:
  - Review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels
  - Employ conservative generation and transmission outage coordination procedures commensurate with long-range weather forecasts to ensure adequate resource availability
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand side management mechanisms called for in operating plans
- GOs with solar PV resources should implement recommendations in the inverter-based resource performance issues alert that NERC issued in March 2023.
- RCs, BAs, and GOs in states affected by the new Good Neighbor Plan should be familiar with its provisions for ensuring electric reliability and have protocols in place to act to preserve generation resources when necessary to support periods of high demand. State regulators and industry should have protocols in place at the start of summer for managing emergent requests.

Discussion

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of the United States while Canada is largely expected to see normal or below-normal average temperatures (see Figure 2). In addition, drought conditions continue across much of the western half of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand.[6] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

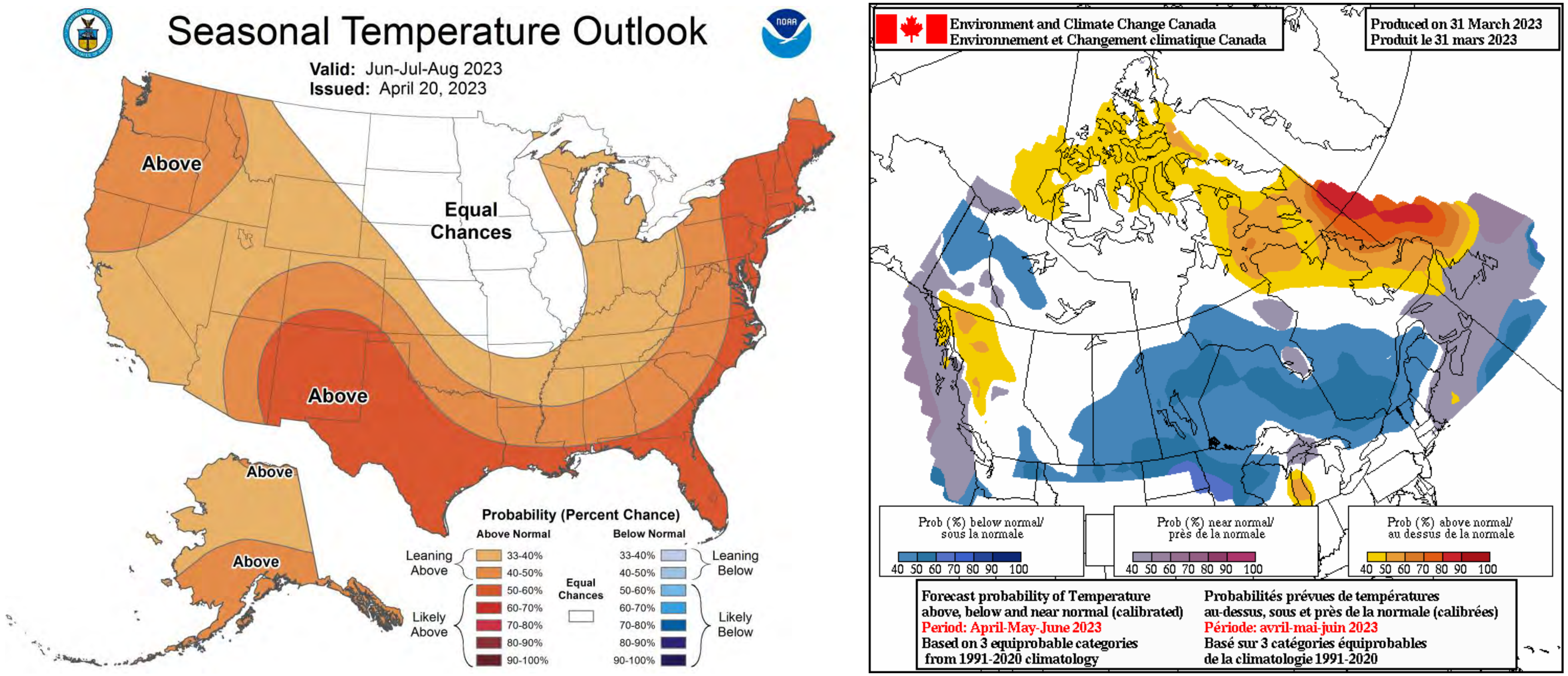


Figure 2: United States and Canada Summer Temperature Outlook[7]

[6] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[7] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Normal or below-normal fire risk is projected for much of the U.S. West at the beginning of the summer; in contrast, Florida, West Texas, and Central Canada project above-normal fire risks for the beginning of summer (see **Figure 3**). BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. Above normal fire risk is projected for much of Canada throughout the summer.

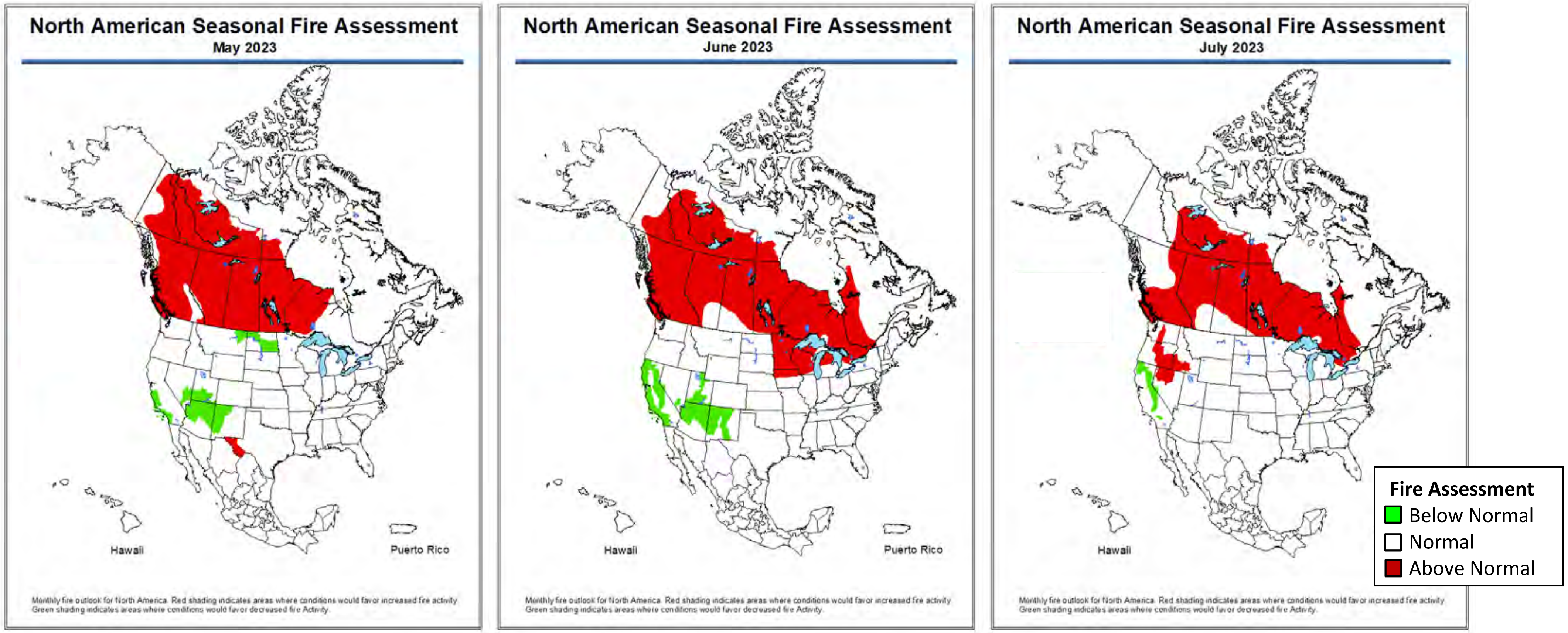


Figure 3: North American Seasonal Fire Assessment for May through July 2023[8]

Wildfire prevention planning in California and some states in the U.S. Northwest include power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the ERO published the *Wildfire Mitigation Reference Guide*[9] to promote preparedness within the North American electric power industry and share the experiences and practices from utilities in the Western Interconnection.

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[8] *See North American Seasonal Fire Assessment and Outlook*, May 2023. Subsequent updates at this link will include August and September: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf

[9] See the NERC *Wildfire Mitigation Reference Guide*, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

Risk Assessments of Resource and Demand Scenarios

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

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 1**, 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.

Highlighted in orange are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section's discussion. The typical outages reserve margin is comprised of anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the 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.

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

Table 1: Seasonal Risk Scenario On-Peak Reserve Margins

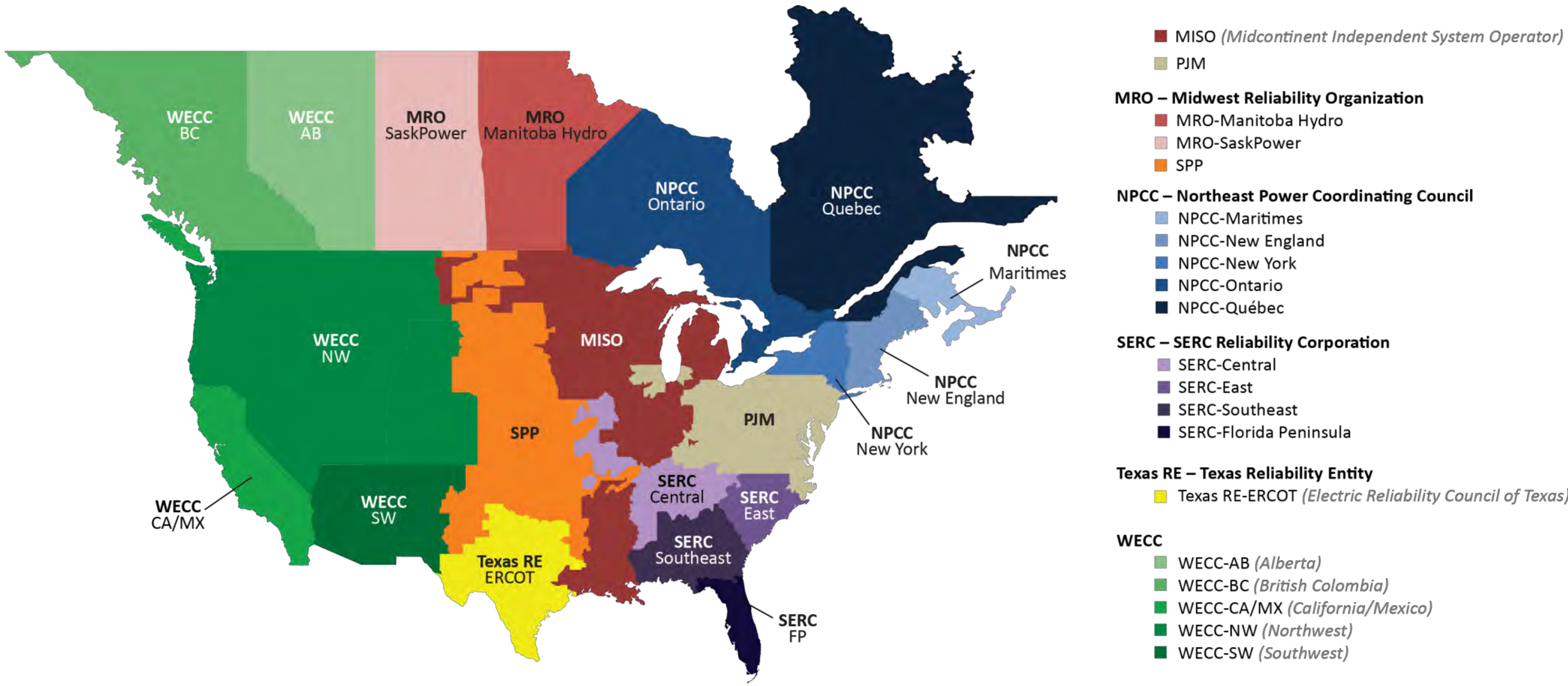
Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	23.0%	4.3%	-6.9%
MRO-Manitoba	29.1%	25.6%	13.1%
MRO-SaskPower	29.1%	12.8%	-1.9%
NPCC-Maritimes	49.7%	39.3%	20.2%
NPCC-New England	17.7%	7.0%	-3.9%
NPCC-New York	30.3%	17.0%	9.9%
NPCC-Ontario	14.0%	14.0%	8.6%
NPCC-Québec	37.1%	37.1%	37.1%
PJM	31.9%	23.4%	8.4%
SERC-Central	18.0%	9.6%	6.4%
SERC-East	19.1%	16.0%	9.0%
SERC-Florida Peninsula	26.6%	19.9%	12.8%
SERC-Southeast	39.6%	36.4%	33.8%
SPP	24.6%	14.3%	-4.0%
Texas RE-ERCOT	23.0%	16.5%	-1.6%
WECC-AB	24.8%	21.9%	8.1%
WECC-BC	28.9%	28.8%	-5.4%
WECC-CA/MX	35.0%	29.0%	-11.9%
WECC-NW	28.5%	22.5%	-12.9%
WECC-SW	19.5%	15.8%	-6.8%

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for the summer of 2023. When forecasted resources in an area fall below expected demand, BAs would need to employ operating mitigations or EEA to obtain the capacity and energy 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.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer 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 SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

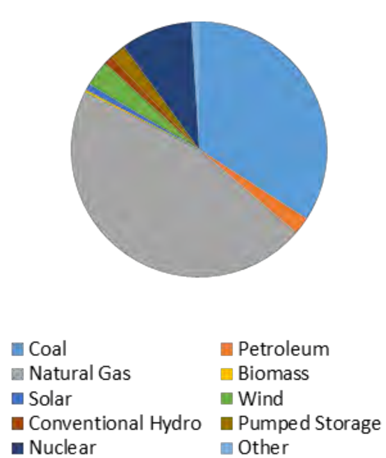
- Demand forecasts and preliminary resource data indicate that MISO is at risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's resources are projected to be lower than in the summer of 2022 while net internal demand has also decreased. Firm transmission imports for this summer have significantly increased; this has resulted in a higher Anticipated Reserve Margin (ARM) of 23% (on an installed capacity basis) compared to 21% last summer. MISO's capacity auction has not concluded at the time of this assessment, which could lead to some change to MISO's firm resources for the summer.
- MISO conducted its annual probabilistic LOLE analysis and determined a 2023 Reference Margin Level (RML) of 15.9% results in an LOLE of 1 day in 10 years. MISO's RML declined from 17.9% in 2022 to 15.9% in 2023 based on the newly implemented seasonal capacity construct and associated modeling improvements that include seasonal outage rates and other enhancements. Comparing the increased ARM to the lower RML indicates improved reliability from the LOLE base case at 1 day in 10 years.
- Performance of wind generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum-generation declarations and energy emergencies. MISO has over 30,300 MW of installed wind capacity; however, the historically-based on-peak capacity contribution is 5,488 MW.

Risk Scenario Summary

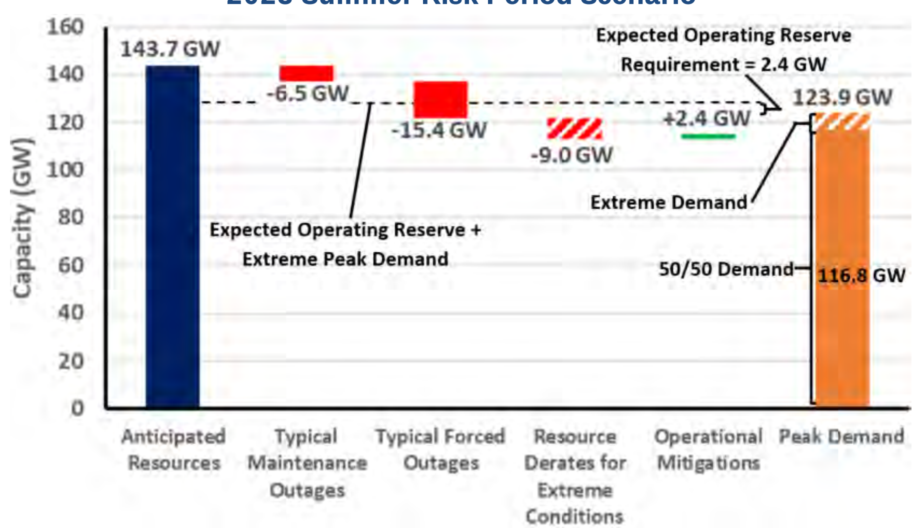
Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., load modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Reserve Margin

On-Peak Fuel Mix



2023 Summer 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 summer average of maintenance and planned outages

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

Extreme Derates: Maximum historical generation outages

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

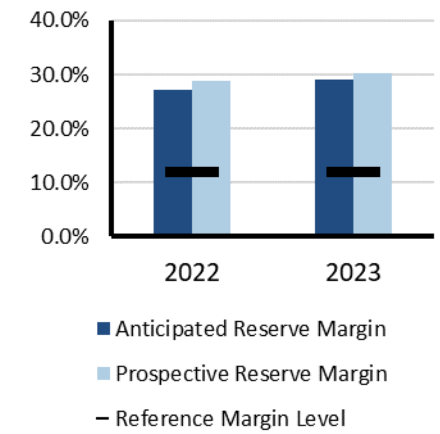
MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and provides approximately 293,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for the summer of 2023.
- The Anticipated Reserve Margin for the summer of 2023 exceeds the 12% Reference Margin Level.
- Six of the seven units at Keeyask Generating Station (hydroelectric) have reached commercial operation status. The remaining unit (Keeyask Unit 6) is listed as a Tier 1 capacity resource as it is operating but awaiting official commercial operation status.
- The 2022 probabilistic work indicated the annual probabilistic indices for the Manitoba Hydro system for 2024 of 29 MWh per year of EUE. Given comparable supply and demand balance, the 2024 EUE is a reasonable estimate for all of 2023.

On-Peak Reserve Margin

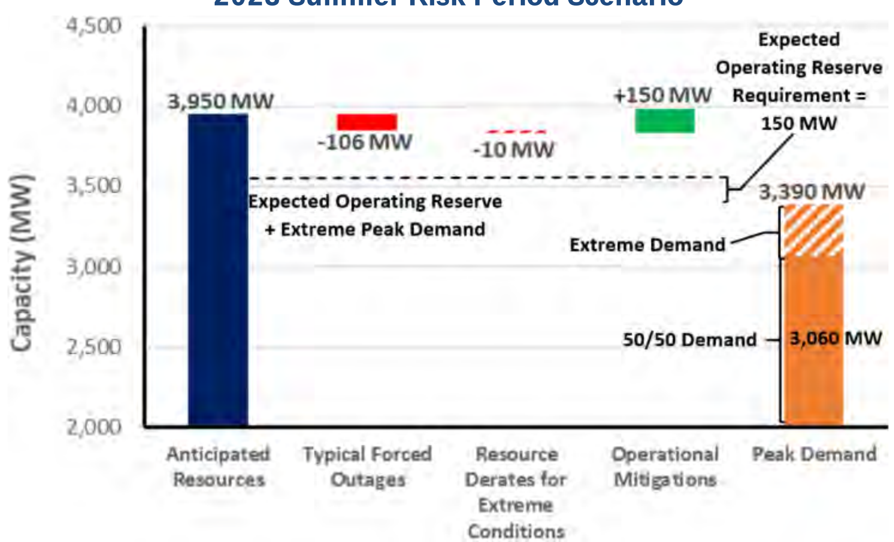


Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix

2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: (50/50) Demand with allowance for Extreme Demand based on extreme summer weather scenario of 37 C (99 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

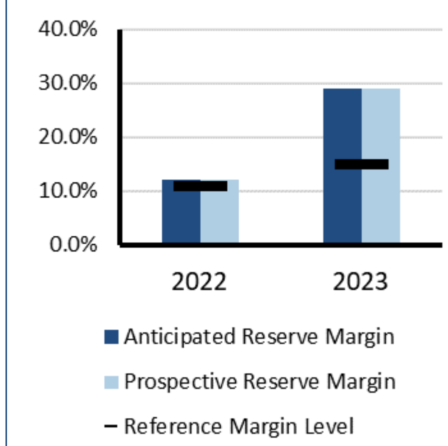
MRO-SaskPower

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

Highlights

- Summer reserve margins in Saskatchewan are higher than in 2022 due to the addition of new wind resources, fewer scheduled generator outages, and lower forecasted peak demand.
- Saskatchewan is a winter-peaking region but also experiences high load in summer during extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro and prepares operating guidelines for any identified issues. Inputs from the Western Area Power Administration are included in the study.
- Results from SaskPower's probabilistic analysis indicate that the expected number of hours with operating reserve deficiency for the 2023 summer season (June to September) is 0.21 hours. The month with the highest probability of EEA is September (0.07 hours). The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outage combined with planned maintenance outages occurs during peak load times in June, July, August, and September months.
- In case of extreme electricity demand from high temperatures 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 if necessary.
- The Reference Reserve Margin was updated to adequately assess energy risks, such as due to changing resource mix, and to align with NERC recommended RRM.

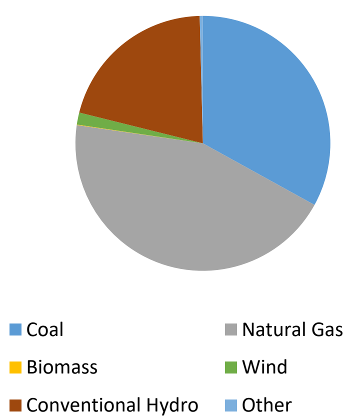
On-Peak Reserve Margin



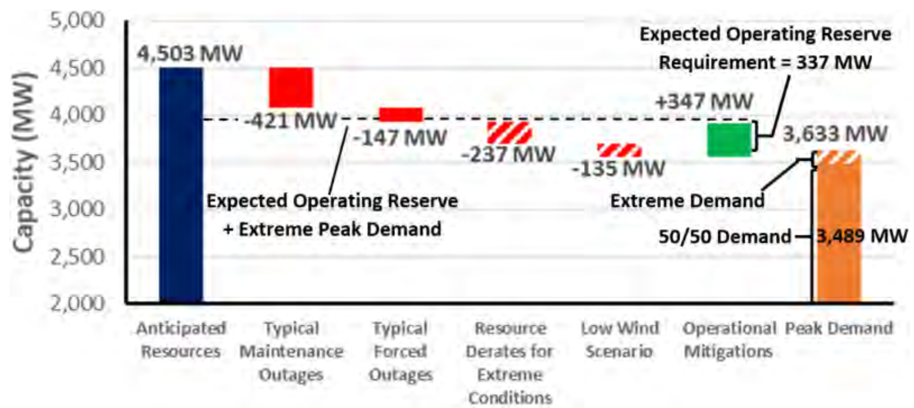
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2023 Summer 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 last three summers less future planned outages (already considered in Anticipated Resources)

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Low Wind Scenario: 33% reduction in nameplate capacity for temperatures between 35° C and 40° C

Operational Mitigations: Estimated non-firm imports and stand-by generators on 2–7 day notice

NPCC-Maritimes

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

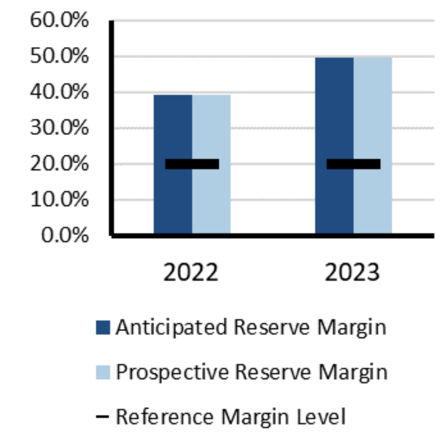
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event 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 the summer. As part of the planning process, dual-fuel units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.
- Based on an NPCC Probabilistic Assessment, minimal amounts of cumulative LOLE (<0.03 days/period), LOLH (<0.11 hours/period), or EUE (<5 MWh/period) were estimated over the May–September summer period for all modeled scenarios. The Maritimes area is winter peaking. The analysis included simulation of a base case (normal 50/50 demand and expected resources) and a highest peak load scenario as well as a low-likelihood, reduced resource case. This reduced resource case considered the impacts of wind capacity being derated by half during July and August due to calm weather, natural-gas-fired units being derated by half in July and August due to supply disruptions (dual-fuel units assumed to revert to oil) as well as reduced transfer capabilities. The highest load level results were based on the two highest load levels of the seven modeled, having approximately a combined 7% chance of occurring.

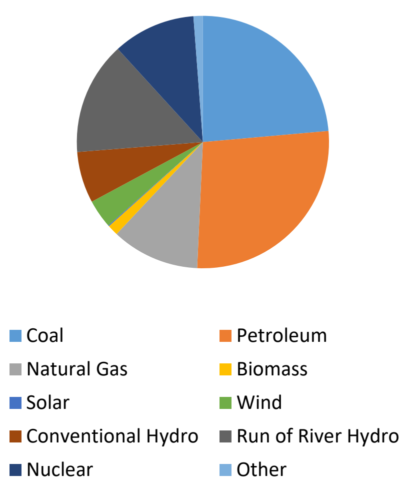
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

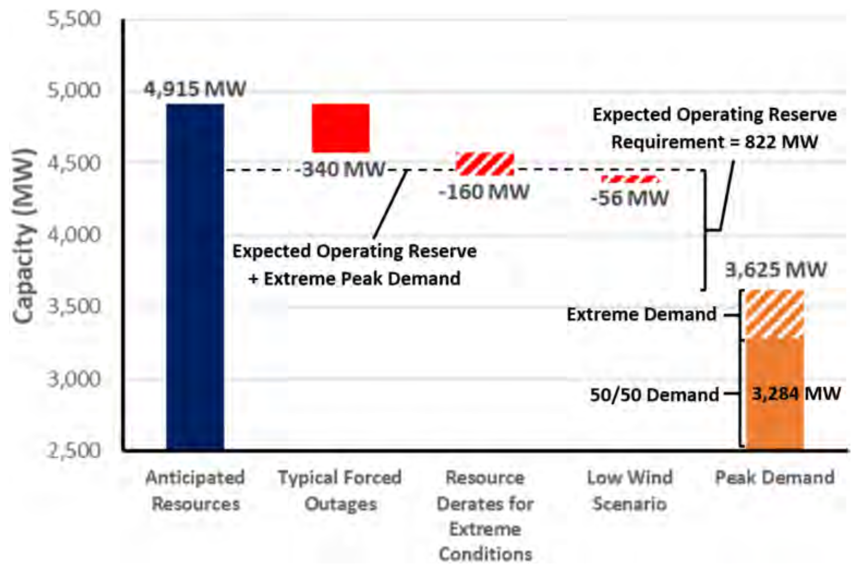
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer 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 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

NPCC-New England

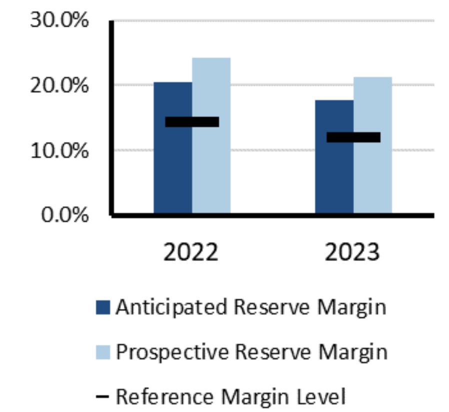
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

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

Highlights

- Reserve margins in New England are projected to be lower this summer due to less existing-certain capacity and firm imports. The New England area expects to have sufficient capacity to meet the 2023 summer peak demand forecast. As of April 4, 2023, The New England area expects to have sufficient resources to meet the 2023 summer peak demand forecast of 24,664 MW, for the weeks beginning June 4 through week beginning September 10, 2023, with the lowest projected net margin of 231 MW (0.9%) during the week of June 25, 2023. The 2023 summer demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.
- Based on an NPCC Probabilistic Assessment, ISO-NE may rely on limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.12 days/period) with associated LOLHs (0.4 hours/period) and EUE (175 MWh/period) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.

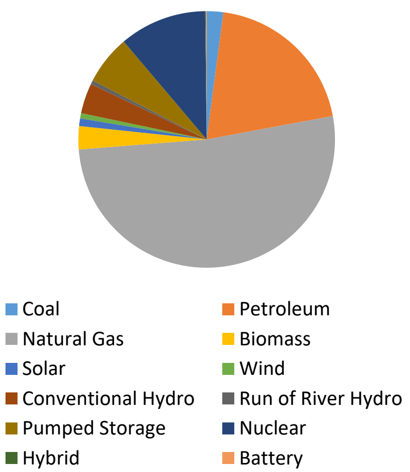
On-Peak Reserve Margin



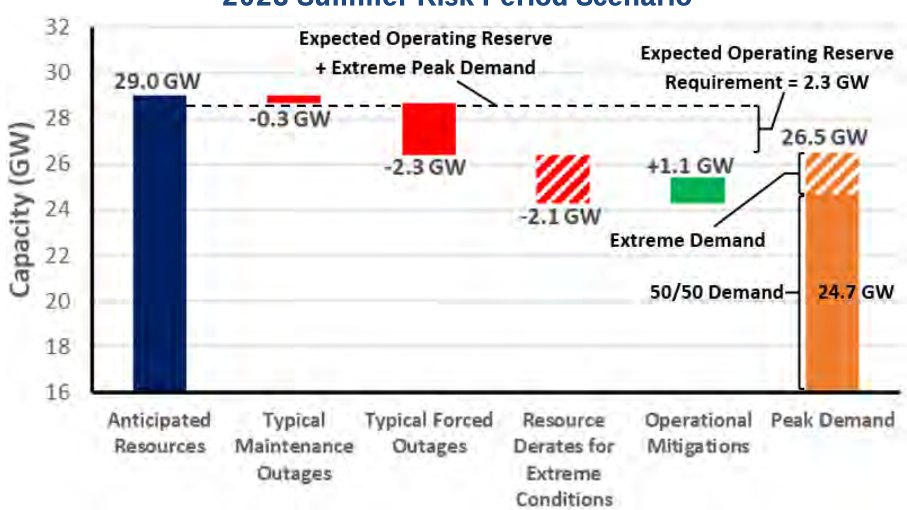
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios with local operating procedures. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. As noted above, the risk of load shedding is low.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance & Forced Outages: Based on historical weekly averages

Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

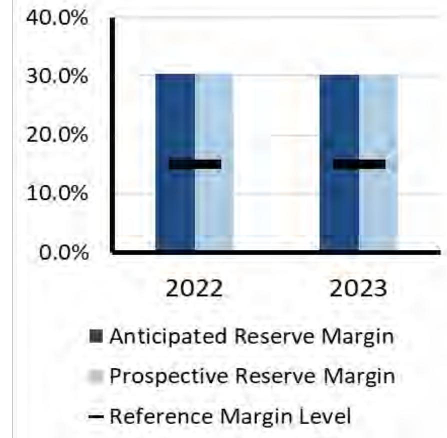
NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The 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. For this SRA, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. New York State Reliability Council approved the 2022–2023 IRM at 20.0%.

Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer. Adequate capacity margins are anticipated, and existing operating procedures are sufficient to handle any issues that may occur.
- A number of combustion turbine generators will be retiring before or during this summer as a result of the New York State Department of Environmental Conservation Peaker Rule. Retirements in 2023 include 16 MW of natural-gas-fired, 53 MW of oil-fired, and 558 MW of dual-fueled generation. New generation includes 556 MW of land-based wind, 90 MW of new solar PV (coming in the third quarter), and 136 MW of new offshore wind generation (coming in the third quarter). Overall, the rule is expected to lead to the retirement of approximately 1,600 MW of capacity by 2025.
- Based on an NPCC Probabilistic Assessment, NYISO may rely on limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.5 days/period) with associated LOLH (1.1 hours/period) and EUE (525 MWh/period) with the highest risk in June and August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.

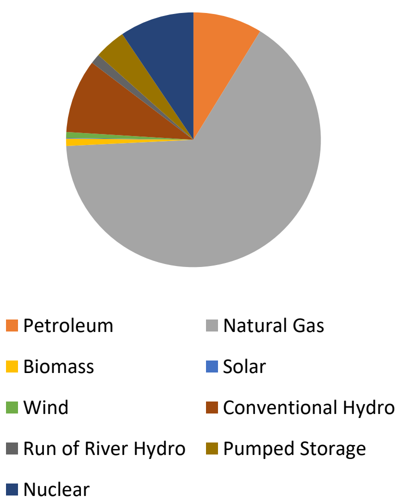
On-Peak Reserve Margin



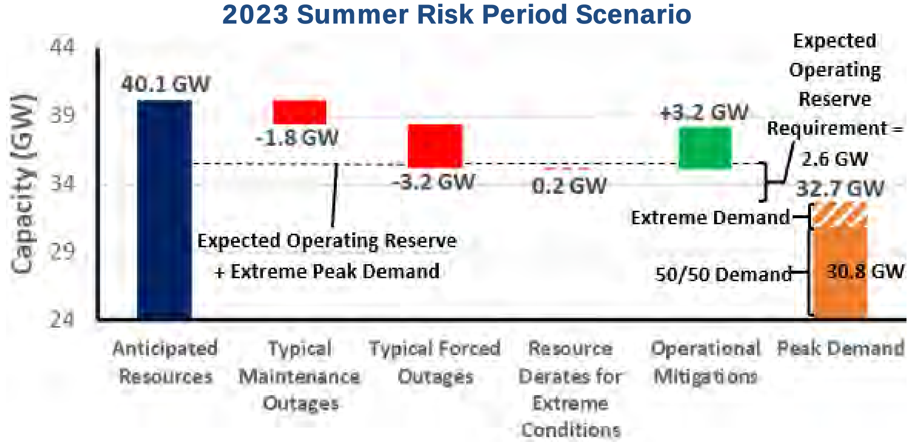
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer 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) extreme demand forecast

Maintenance Outages:

Forced Outages: Based on historical 5-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area emergency operations manual

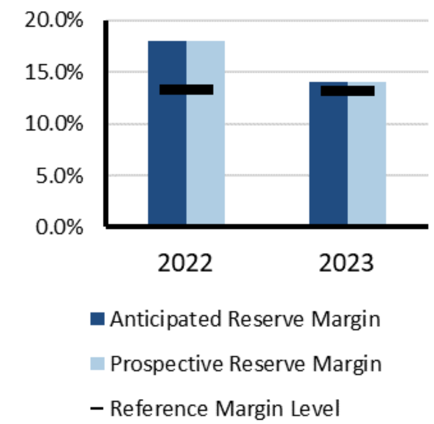
NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

- Ontario has entered a period during which generation and transmission outages will be increasingly difficult to accommodate. The IESO expects these conditions to persist for the foreseeable future. IESO is strongly encouraging market participants to plan ahead and coordinate with IESO to ensure planned outages can be appropriately scheduled.
- Under both normal and extreme weather conditions, Ontario may rely on imports and outage management for a significant number of weeks during the 2023 summer assessment period primarily as a result of coincident generator outages. Should market participants be unable to reschedule certain outages during this period, Ontario may have to rely on more than 2,000 MW of non-firm supply from other areas and/or additional operating actions to ensure reliability.
- Based on an NPCC Probabilistic Assessment, Ontario is expected to need only limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood cases, which resulted in small LOLH (0.3 hours). These results model import availability and indicate that Ontario will be able to obtain the necessary supplies from neighbors over a range of most conditions, but there is a risk during extreme demand and low resource periods.
- The ongoing transmission outage at the New York–St. Lawrence interconnection continues to impact import and export capacity between Ontario and New York. This issue is expected to be resolved by the end of the fourth quarter of 2023.

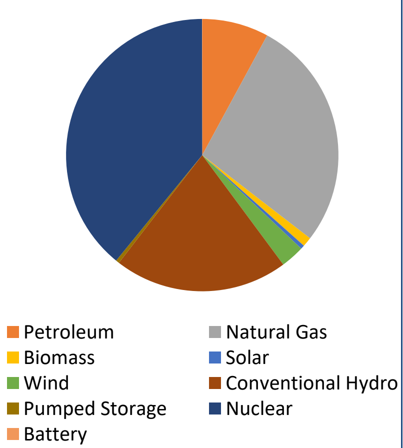
On-Peak Reserve Margin



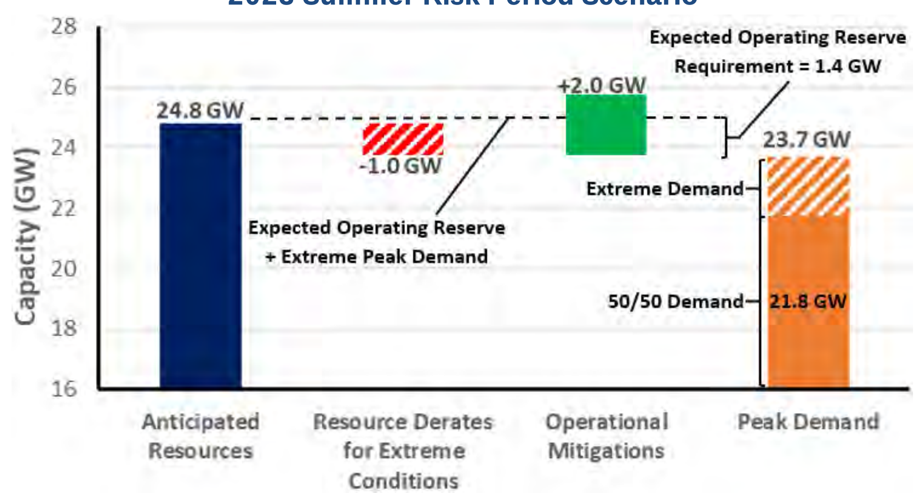
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could result in the need to employ operating mitigations (i.e., demand response and non-firm transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix



2023 Summer 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 based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies

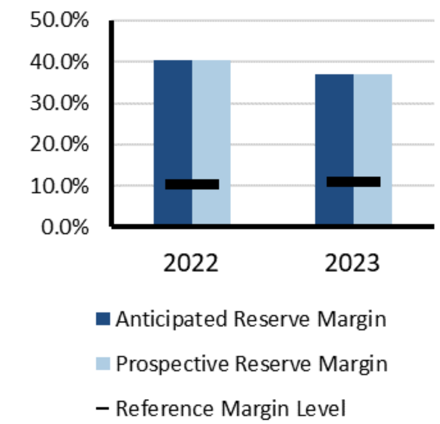
NPCC-Québec

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 high voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- The Québec area forecasted summer peak demand (excluding April, May, and September) is 22,859 MW during the week of August 13, 2023, with a forecasted net margin of 7,202 MW (31.5%). No particular resource adequacy problems are forecasted, and the Québec area expects to be able to provide assistance to other areas up to the transfer capability available.
- In the Québec RC area, most transmission line, transformer, and generating unit maintenance is done during the summer period. Internal transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales, and additional uncertainty margins. They should not impact inter-area transfer capabilities with neighboring systems. During the 2023 summer operating period, some maintenance outages are scheduled on the interconnections. Maintenance is coordinated with neighboring RC areas so as to leave maximum capability to summer-peaking areas.
- Based on an NPCC Probabilistic Assessment, Québec is expected to need only limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.

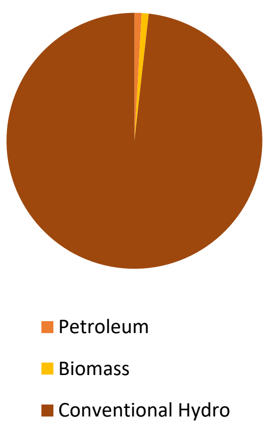
On-Peak Reserve Margin



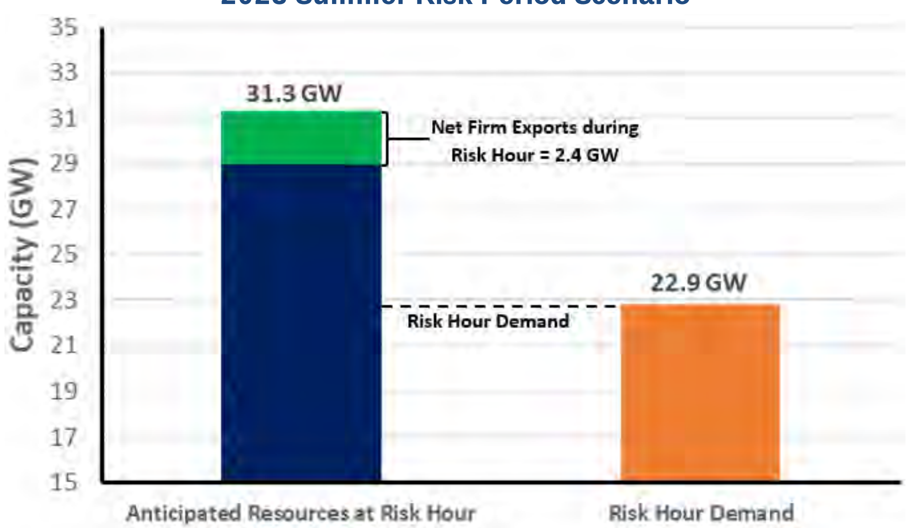
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Net Firm Transfers: Anticipated exports to neighbors during the risk hour

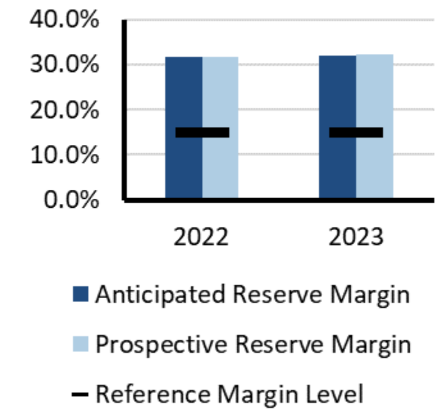
PJM

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

Highlights

- PJM expects no resource problems over the entire 2023 summer peak season. Installed capacity is over twice the PJM reserve requirement necessary to meet the 1-day-in-10-years LOLE criterion.
- The 2022 PJM reserve requirement study used to establish the target installed reserve margin of 14.9% analyzed a wide range of load scenarios (low, regular and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted net peak demand.
- No other reliability issues are expected.

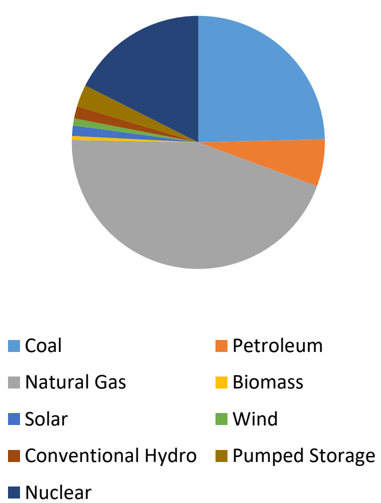
On-Peak Reserve Margin



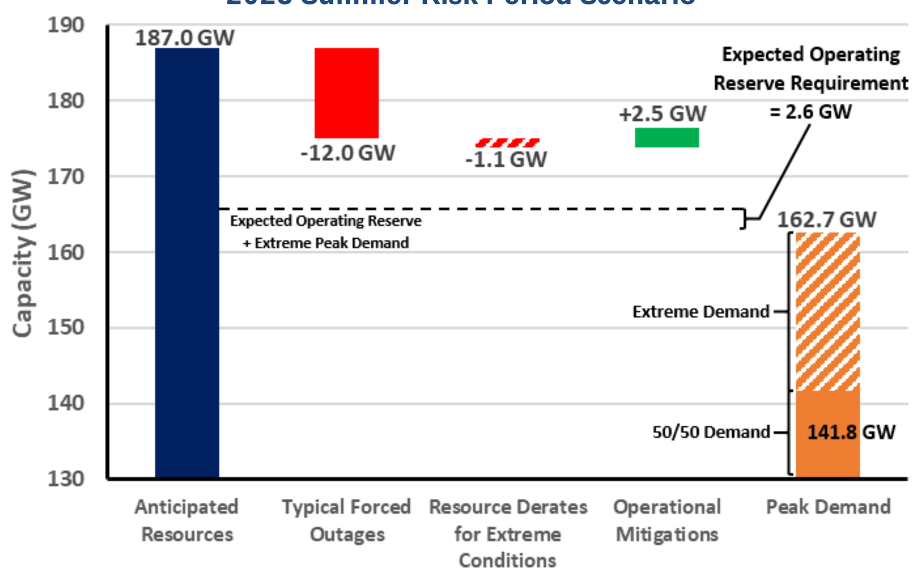
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Based on historical data and trending

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

Operational Mitigations: A total of 2.5 GW based on operational/emergency procedures

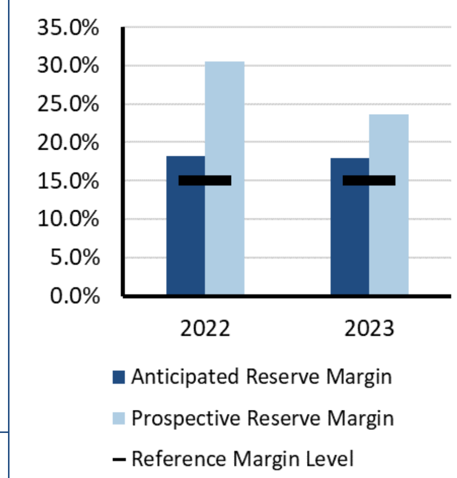
SERC-Central

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

Highlights

- Entities in SERC-Central have not identified any potential reliability issues for the upcoming summer season. Entities anticipate having adequate system capacity for the upcoming summer season and are equipped to address unexpected short-term issues by leveraging diverse generation portfolios and spot purchases from the power markets when necessary.
- Non-economic dispatch (out of merit) of available coal-fired generators ahead of the upcoming summer season is anticipated in order to build inventory and limit consumption of fuel and consumables for plant operations and mitigate supply and transportation challenges during the summer.
- Each entity continues to work collaboratively to ensure reliability for its area within SERC and to promote reliability and adequacy across the entire SERC Regional Entity.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups among others. These working groups help the entities identify and address emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis indicates negligible risk for resource shortfall. The 2022 study found negligible LOLH and EUE during summer months for a similar resource mix and demand levels.

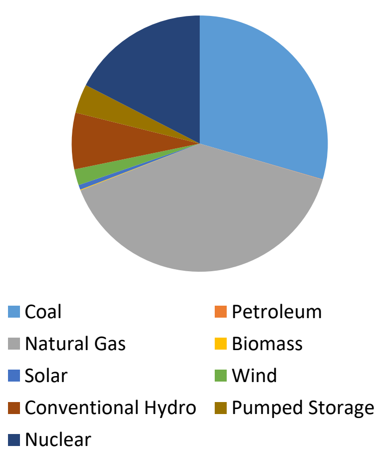
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 1.9 GW based on operational/emergency procedures

SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

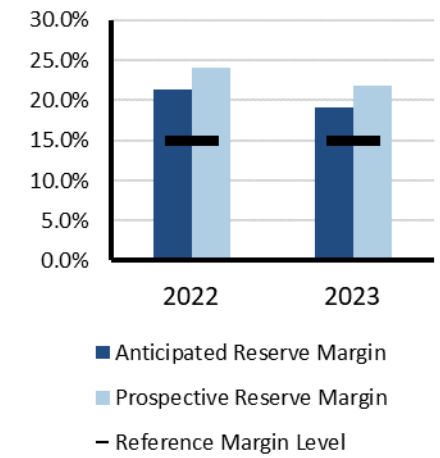
Highlights

- SERC-East is transitioning to a hybrid-peaking (both summer and winter peaking) area as solar PV reduces summer peak demand and electrification of heating drives up winter peak demand.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.
- Entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain reliability to the system.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis shows a low risk for resource shortfall during the months of July and August. The 2022 study found LOLH of 0.005 hours and EUE of 2.381 MWh during summer months for a similar resource mix and demand levels.

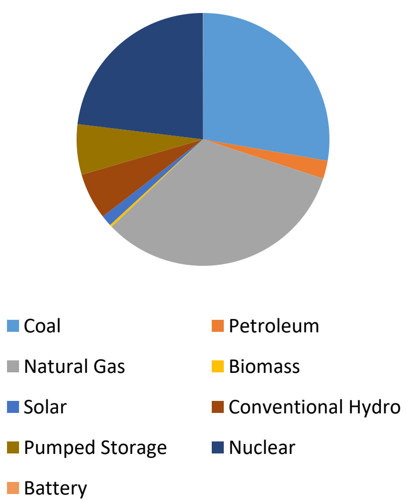
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

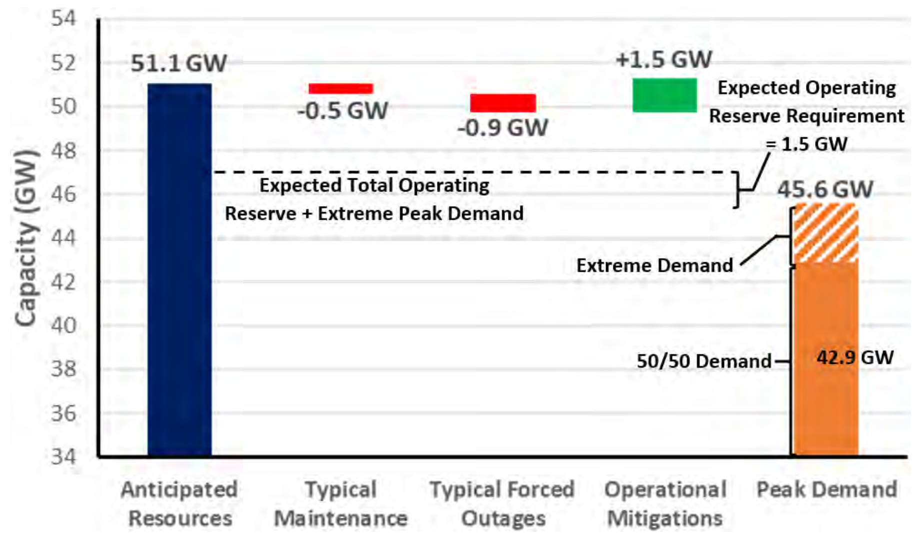
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.5 GW based on operational/emergency procedures

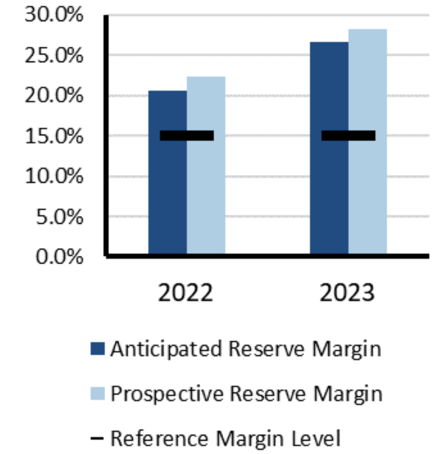
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

Highlights

- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.
- Entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain system reliability.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- SERC probabilistic analysis indicates negligible risk for resource shortfall. The 2022 study found negligible LOLH and EUE during summer months for a similar resource mix and demand levels

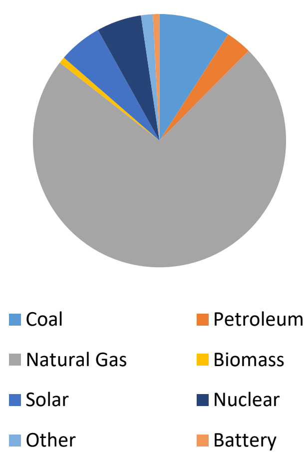
On-Peak Reserve Margin



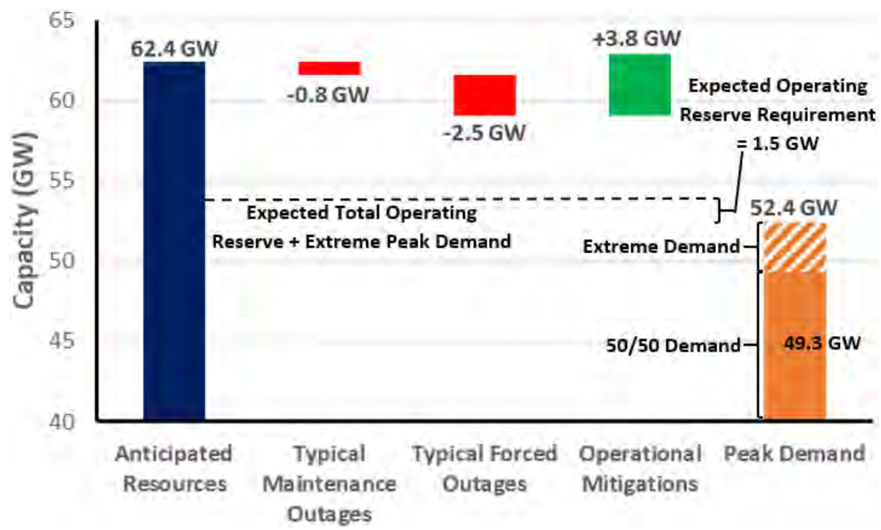
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

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

SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 RCs.

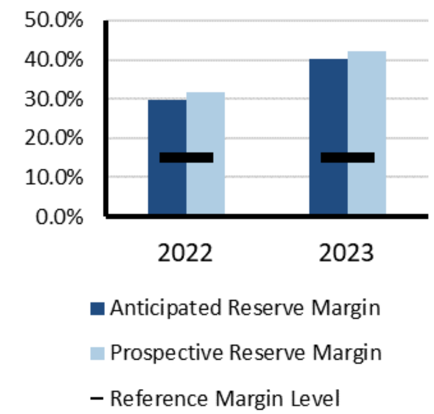
Highlights

- Entities have not identified any emerging reliability issues for the upcoming summer season that will impact resource adequacy.
- The available system capacity for the upcoming summer season meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm natural gas contracts, and power purchases.
- Entities continue to participate actively in the SERC near-term and long-term working groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis indicates almost no risk for resource shortfall.

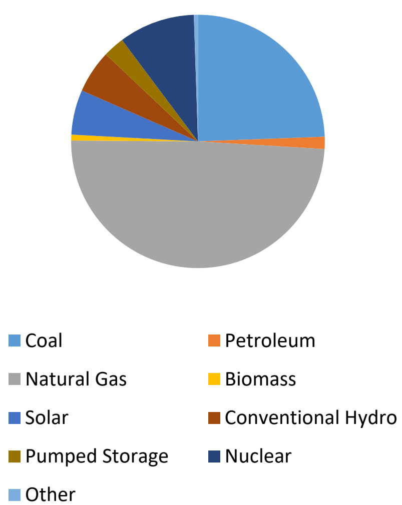
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

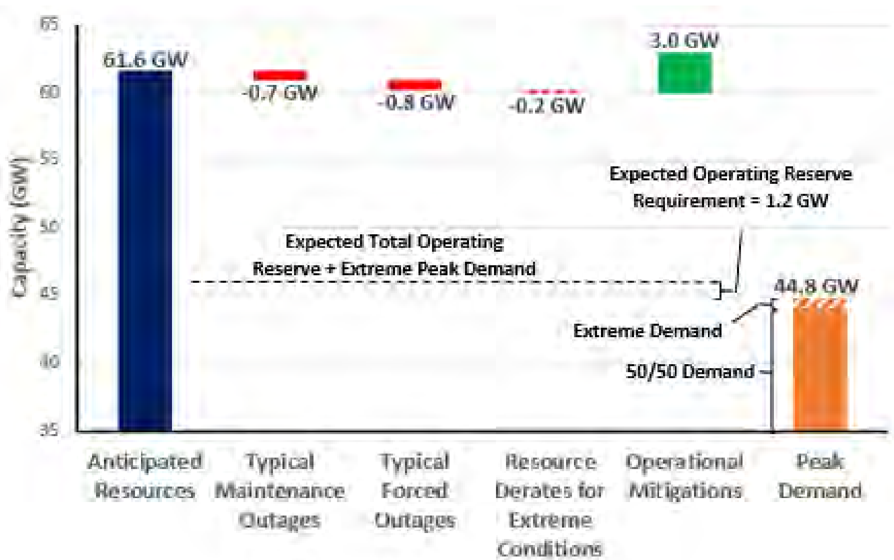
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.0 GW based on operational/ emergency procedures

SPP

SPP PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the 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.

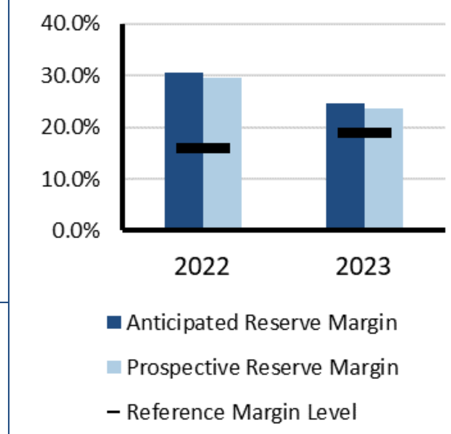
Highlights

- At this time, SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2023 summer season.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- SPP performed a statistical analysis of risk of energy emergencies for the upcoming summer based on historical data. They found it likely that operators would use part of the 2 GW operating reserves and issue EEA1 and EEA2 level approximately one day each summer; it is likely that operators would deplete all operating reserves approximately once every five summers, resulting in an EEA3.
- Using the current operational processes and procedures, SPP will continue to assess the needs for the 2023 summer season and will adjust as needed to ensure that real-time reliability is maintained throughout the summer time frame.

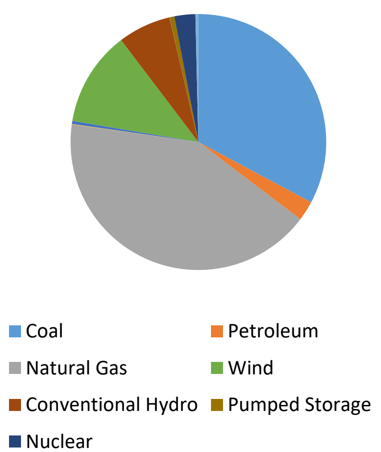
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e. demand response and transfers from neighboring systems) and EEAs.

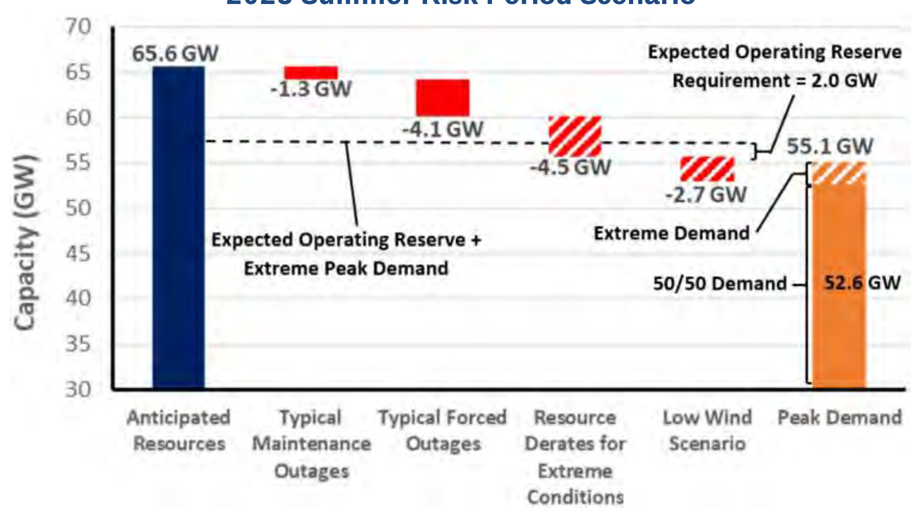
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer 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 is a 5% increase from net internal demand

Maintenance & Forced Outages: Represent 5-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

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 summer-peaking. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the RE functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the Reliability Monitor for the Texas power grid.

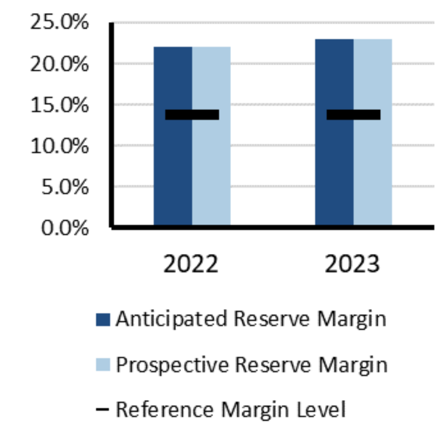
Highlights

- Given an Anticipated Reserve Margin of 23% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves in expected normal summer system conditions.
- Solar PV nameplate capacity expected for the 2023 summer season is 4.4 GW higher than the forecast amount reported for the 2022 SRA.
- Several generator owners in the ERCOT area indicated they could run out of NOx emission allowances by July 2023 under U.S. EPA's Good Neighbor Plan. Texas filed a motion to stay the EPA's regulatory action. A delay in implementation has alleviated these concerns. ERCOT's probabilistic risk assessment indicates a low probability of energy emergency conditions during the summer peak load period, but the risk increases into the early evening hours due reductions of solar PV generation. There is a 4% probability that ERCOT will declare an EEA1 during the expected daily peak load hour increasing up to 19% probability at the highest risk hour ending at 8:00 p.m.
- System stability and strength stemming from the growth of IBRs remains a concern. ERCOT is also experiencing large increases in renewable production curtailments due to transmission constraints, and these curtailments are increasingly occurring at solar PV sites.

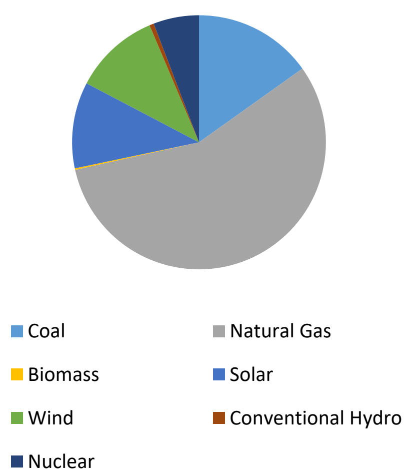
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme peak-demand scenarios. Extreme generator outages combined with low-wind output during extreme peak demand could result in the need to employ operating mitigations such as demand response, EEAs, and localized load shedding.

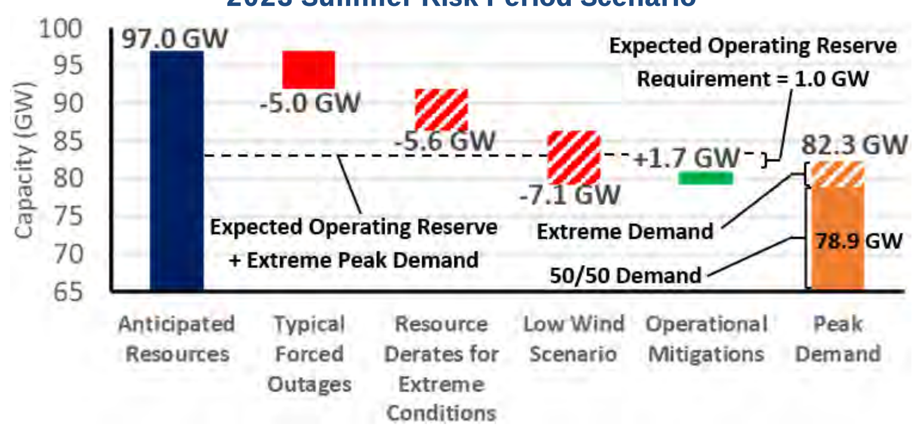
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer 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 represents weather conditions 2% worse than summer peak in 2011

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Extreme Derates: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last five (2019–2021) summer seasons

Operational Mitigations: Additional capacity from switchable generation and additional imports

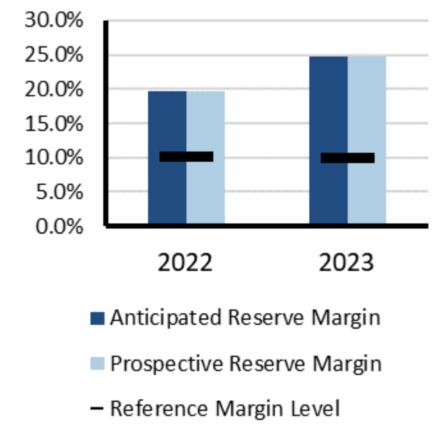
WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. 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

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- There is 35% less coal-fired generator capacity in Alberta compared to last summer (446 MW). Resource additions include 554 MW of natural-gas-fired generation, 336 MW of new solar PV resources, and 1,350 MW of new wind generation.
- Based on a WECC Probabilistic Assessment, the WECC-AB assessment area had negligible LOLH and EUE.
- Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

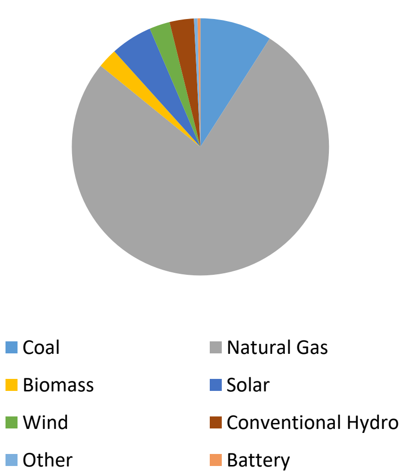
On-Peak Reserve Margin



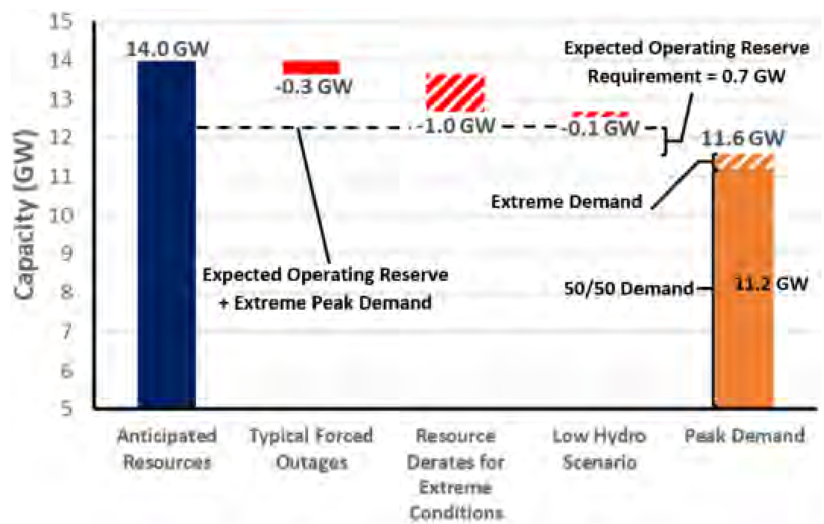
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

WECC-BC

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity 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 include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. 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.

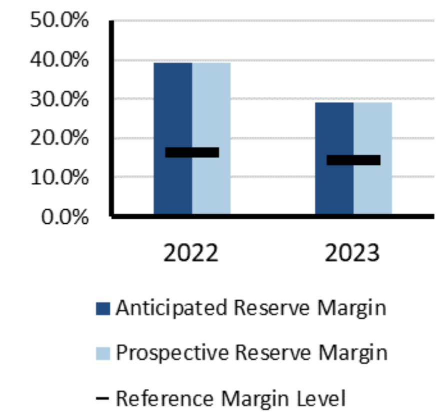
Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- BC shows adequate reserve margins to meet demand under extreme conditions.
- Based on a WECC Probabilistic Assessment, the WECC-BC assessment area had negligible LOLH and EUE.
- BC is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m., under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

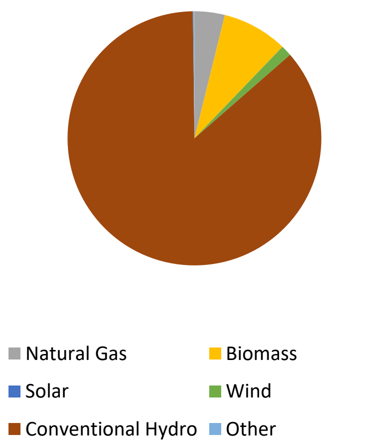
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under the extreme peak demand and outage scenarios studied.

On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

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

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

WECC-CA / MX

WECC-CA/MX is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. 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.

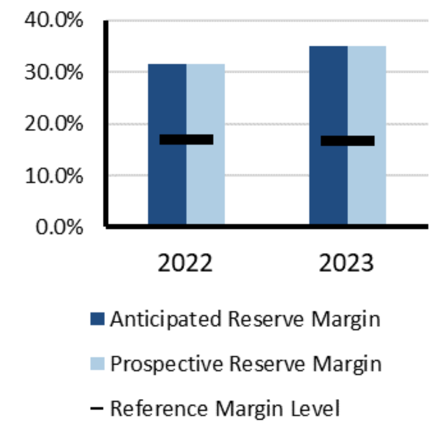
Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- CA/MX shows adequate reserve margins under expected conditions on the peak hour. However, increased risk occurs during the hours after peak demand and into the evening due to the variability of energy availability. CA/MX is typically reliant on imports during these periods.
- Based on a WECC Probabilistic Assessment, WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<0.5 hours) this summer. Variation in LOLH is attributable to the amount of Tier 1 resources that connect before the later months.
- CA/MX is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.
- For the peak riskiest hour ending 8:00 pm (four hours later than the peak) under an extreme summer peak load, CA/MX would need to rely on increased imports to maintain adequate reserves. Under expected net internal demand for the same riskiest hour (not an extreme summer peak for that hour), any of the typical outages or extreme derates would also cause a need for increased reliance on imports.

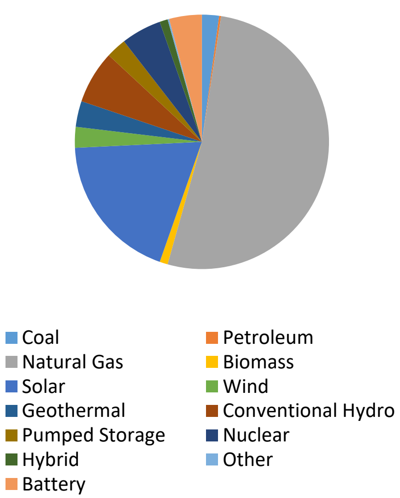
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

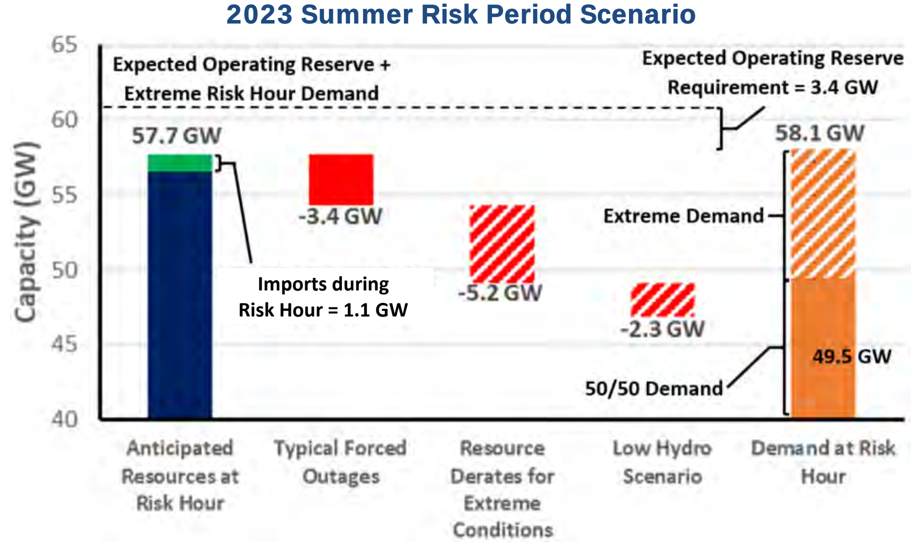
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at 8:00 p.m. local time as solar PV output is diminished and demand remains high

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

Forced Outages: Estimated using market forced outage model

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

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

WECC-NW

WECC-NW is a summer-peaking assessment area in the WECC Regional Entity. 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 include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. 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.

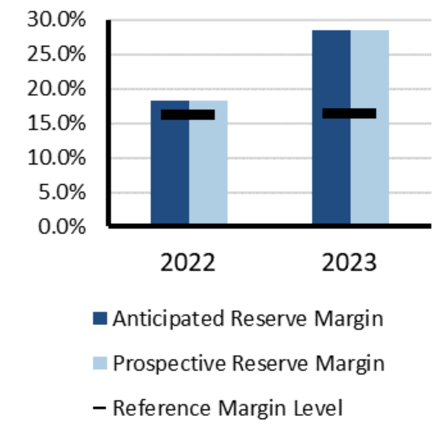
Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- NW shows adequate reserve margins under expected conditions on the peak hour. However, NW shows increased risk a few hours later during the peak riskiest hour, due to the variability of energy availability later in the evenings. NW would be reliant on increased imports.
- Based on a WECC Probabilistic Assessment, the WECC-NW assessment area had negligible LOLH and EUE.
- WECC-NW would need to rely on imports to maintain adequate reserves on the peak riskiest hour (five hours later at 9:00 p.m.) under an extreme summer peak load and either extreme thermal or extreme hydro derates or any combination of two other extreme derate scenarios.

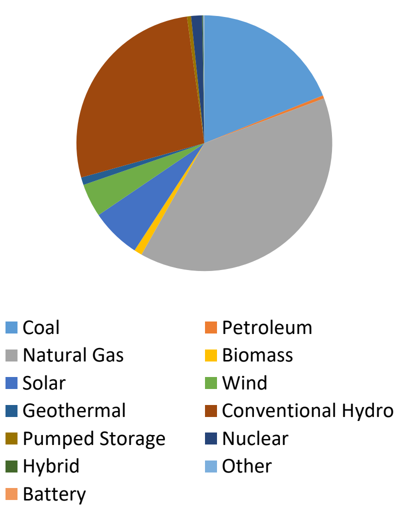
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

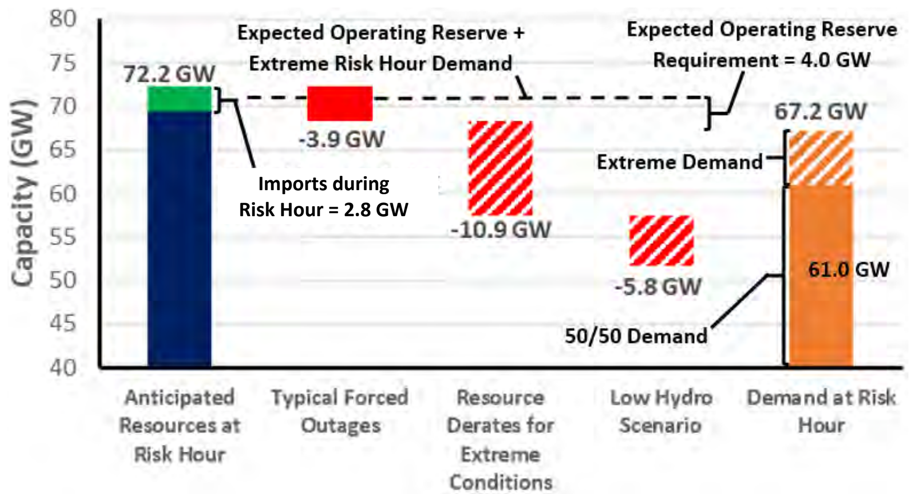
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

- **Risk Period:** Highest risk for unserved energy at 9:00 p.m. local time as solar PV output is diminished and demand remains high
- **Demand Scenarios:** Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Using (90/10) scenario
- **Low Hydro Scenario**: Reduced hydro availability resulting from drought conditions

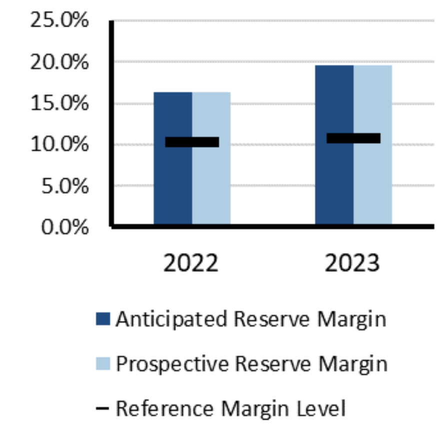
WECC-SW

WECC-SW is a summer-peaking assessment area in the WECC Regional Entity. 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 include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. 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

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- WECC-SW shows adequate reserve margins to meet demand under extreme conditions.
- Based on a WECC Probabilistic Assessment, the WECC-SW assessment area had negligible LOLH and EUE.
- WECC-SW is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 5:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

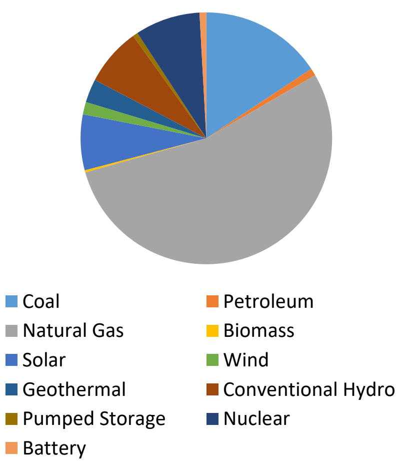
On-Peak Reserve Margin



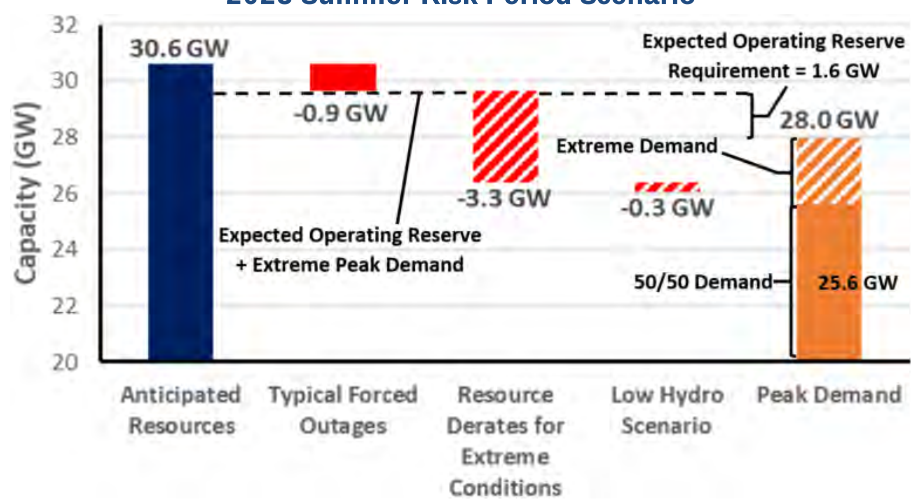
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

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.
- *2022 Long-Term Reliability Assessment* data has been used for most of this 2023 summer 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[10] or total internal demand for the summer and winter of each year.[11]
- Total internal demand projections are based on normal weather (50/50 distribution[12]) and are provided on a coincident[13] 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 PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

[10] *Glossary of Terms* used in NERC Reliability Standards
[11] The summer season represents June–September and the winter season represents December–February.
[12] 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.
[13] 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.

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, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand.

Resource Adequacy

The 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.[14] 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 2023 summer as shown in **Figure 4**.

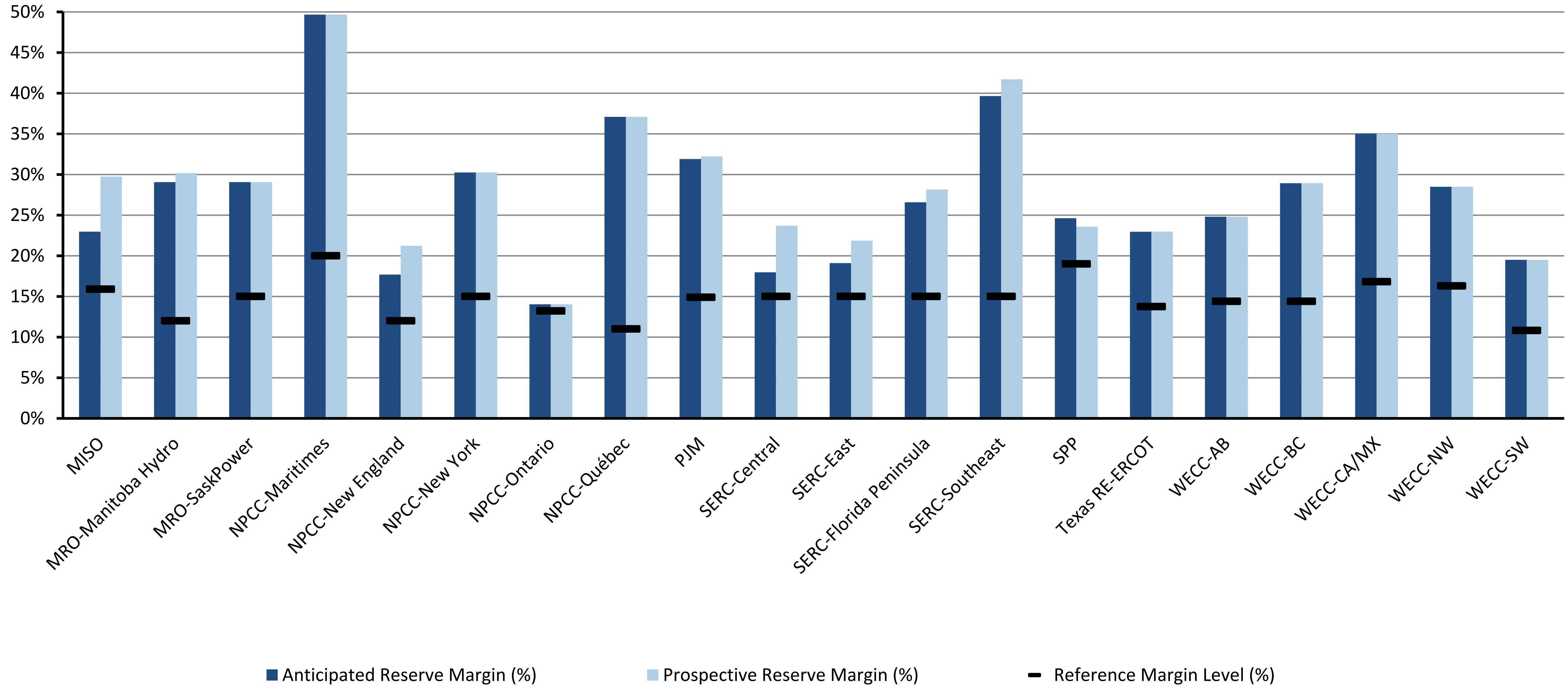
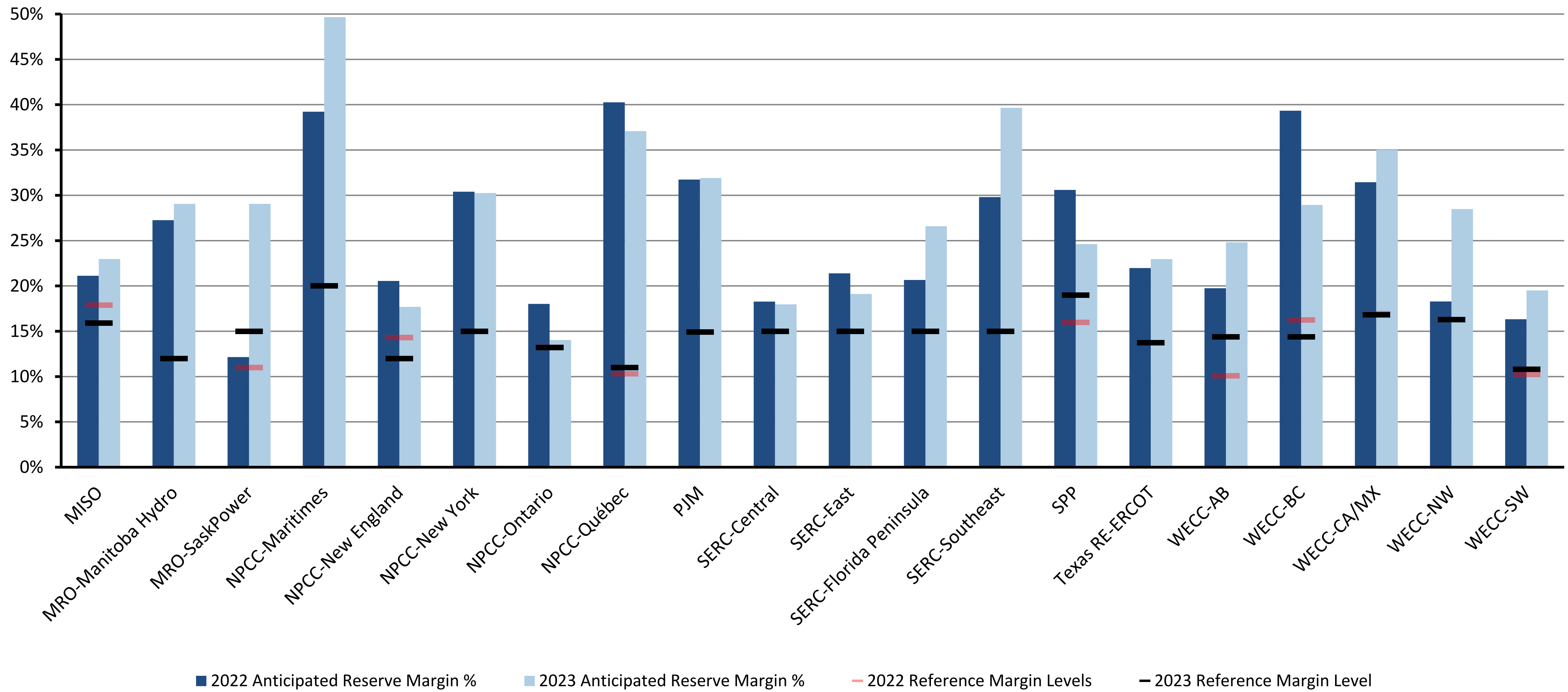


Figure 4: Summer 2023 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[14] 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 5 provides the relative change in the forecast Anticipated Reserve Margins from the 2022 summer to the 2023 summer. A significant decline can indicate potential operational issues that emerge between reporting years. NPCC-Ontario, SPP and WECC-BC have noticeable reductions in anticipated resources with NPCC-Ontario close to falling below its Reference Margin Level for the 2023 summer. NPCC-Ontario is experiencing ongoing nuclear refurbishments and recent retirements will make it difficult to accommodate unplanned generator or transmission outages. NPCC-Ontario will rely on demand response and transfers from neighbors during a higher load scenario to avoid load interruption. The lower Anticipated Reserve Margins for NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB do not present reliability concerns on peak for this upcoming summer. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.



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

Figure 5: Summer 2022 and Summer 2023 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 6**.[15] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

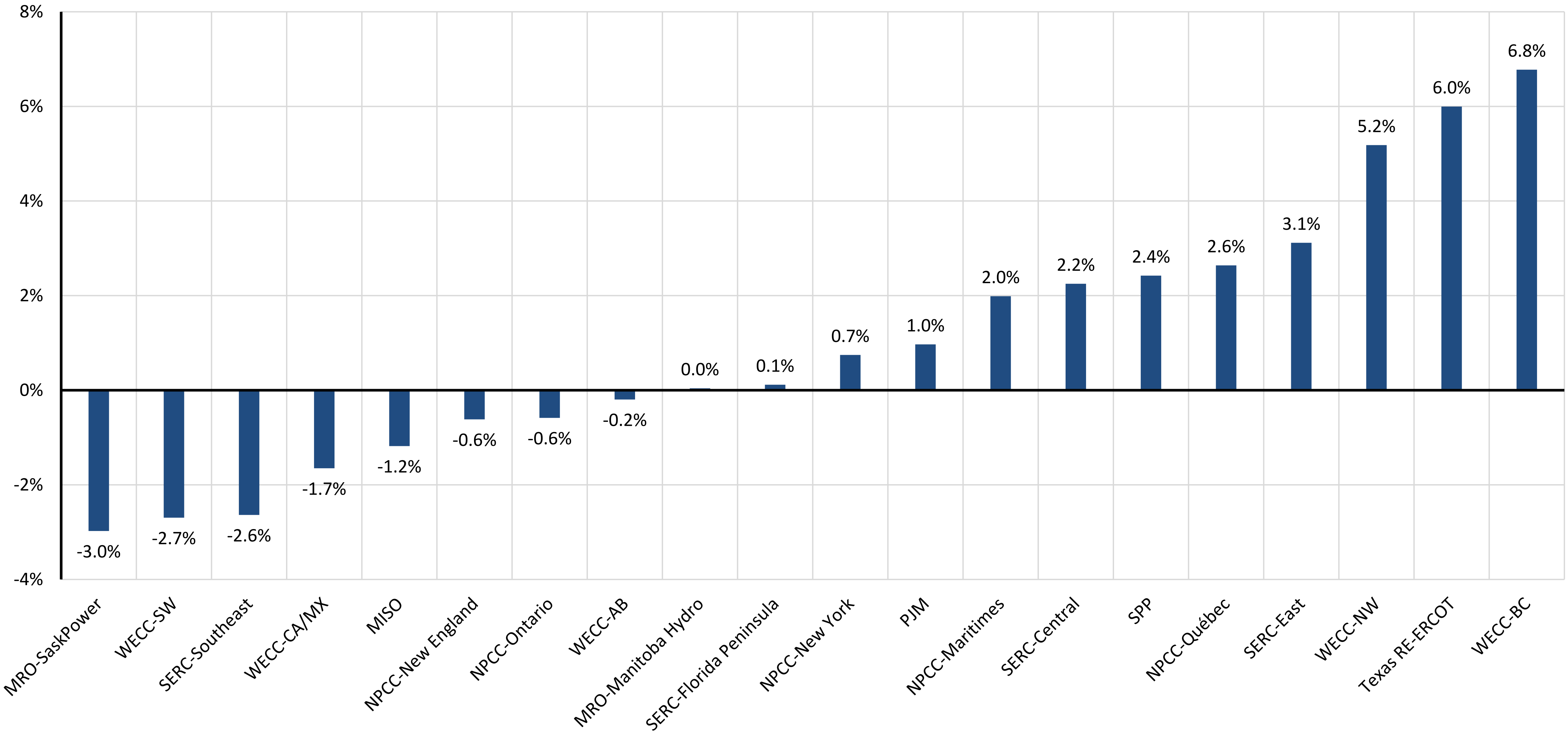


Figure 6: Change in Net Internal Demand—Summer 2022 Forecast Compared to Summer 2023 Forecast

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

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,506	123,728	-0.6%
Demand Response: Available	6,287	6,903	9.8%
Net Internal Demand	118,220	116,825	-1.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	141,844	140,650	-0.8%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,353	3,018	123.1%
Anticipated Resources	143,197	143,668	0.3%
Existing-Other Capacity	669	668	-0.1%
Prospective Resources	149,756	151,579	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.1%	23.0%	1.8
Prospective Reserve Margin	26.7%	29.7%	3.1
Reference Margin Level	17.9%	15.9%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,059	3,060	0.0%
Demand Response: Available	0	0	-
Net Internal Demand	3,059	3,060	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,523	5,731	3.8%
Tier 1 Planned Capacity	186	91	-50.9%
Net Firm Capacity Transfers	-1,816	-1,872	3.1%
Anticipated Resources	3,893	3,950	1.5%
Existing-Other Capacity	44	34	-23.4%
Prospective Resources	3,937	3,984	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.3%	29.1%	1.8
Prospective Reserve Margin	28.7%	30.2%	1.5
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,656	3,539	-3.2%
Demand Response: Available	60	50	-16.7%
Net Internal Demand	3,596	3,489	-3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,743	4,213	12.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,033	4,503	11.7%
Existing-Other Capacity	0	0	-
Prospective Resources	4,033	4,503	11.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.2%	29.1%	16.9
Prospective Reserve Margin	12.2%	29.1%	16.9
Reference Margin Level	11.0%	15.0%	4.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,475	3,612	3.9%
Demand Response: Available	255	328	28.6%
Net Internal Demand	3,220	3,284	2.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,419	4,834	9.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	64	81	26.6%
Anticipated Resources	4,483	4,915	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	4,483	4,915	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.2%	49.7%	10.4
Prospective Reserve Margin	39.2%	49.7%	10.4
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,300	25,111	-0.7%
Demand Response: Available	483	447	-7.5%
Net Internal Demand	24,817	24,664	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	28,626	27,997	-2.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,292	1,030	-20.3%
Anticipated Resources	29,918	29,027	-3.0%
Existing-Other Capacity	911	872	-4.3%
Prospective Resources	30,829	29,899	-3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.6%	17.7%	-2.9
Prospective Reserve Margin	24.2%	21.2%	-3.0
Reference Margin Level	14.3%	12.0%	-2.3

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,546	22,439	-0.5%
Demand Response: Available	666	687	3.1%
Net Internal Demand	21,880	21,752	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	25,648	24,575	-4.2%
Tier 1 Planned Capacity	24	9	-61.5%
Net Firm Capacity Transfers	150	223	48.5%
Anticipated Resources	25,822	24,807	-3.9%
Existing-Other Capacity	0	0	-
Prospective Resources	25,822	24,807	-3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.0%	14.0%	-4.0
Prospective Reserve Margin	18.0%	14.0%	-4.0
Reference Margin Level	13.3%	13.2%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,765	32,049	0.9%
Demand Response: Available	1,170	1,226	4.8%
Net Internal Demand	30,595	30,823	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,431	37,216	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,465	2,932	18.9%
Anticipated Resources	39,896	40,148	0.6%
Existing-Other Capacity	0	0	-
Prospective Resources	39,896	40,148	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	30.3%	-0.1
Prospective Reserve Margin	30.4%	30.3%	-0.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,271	22,859	2.6%
Demand Response: Available	0	0	-
Net Internal Demand	22,271	22,859	2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,542	33,690	0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,304	-2,353	2.1%
Anticipated Resources	31,238	31,337	0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	31,238	31,337	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.3%	37.1%	-3.2
Prospective Reserve Margin	40.3%	37.1%	-3.2
Reference Margin Level	10.3%	11.0%	0.7

PJM			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	148,938	149,059	0.1%
Demand Response: Available	8,527	7,288	-14.5%
Net Internal Demand	140,411	141,771	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	184,837	186,540	0.9%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	124	463	273.4%
Anticipated Resources	184,971	187,003	1.1%
Existing-Other Capacity	0	0	-
Prospective Resources	185,095	187,466	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.7%	31.9%	0.2
Prospective Reserve Margin	31.8%	32.2%	0.4
Reference Margin Level	14.9%	14.9%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,883	43,889	2.3%
Demand Response: Available	1,298	1,008	-22.3%
Net Internal Demand	41,585	42,881	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	49,380	50,452	2.2%
Tier 1 Planned Capacity	486	0	-100.0%
Net Firm Capacity Transfers	612	624	2.0%
Anticipated Resources	50,478	51,076	1.2%
Existing-Other Capacity	1,097	1,182	7.8%
Prospective Resources	51,575	52,258	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.4%	19.1%	-2.3
Prospective Reserve Margin	24.0%	21.9%	-2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,267	42,223	2.3%
Demand Response: Available	1,841	1,910	3.7%
Net Internal Demand	39,426	40,313	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,424	46,964	-1.0%
Tier 1 Planned Capacity	0	93	-
Net Firm Capacity Transfers	-795	1,068	-
Anticipated Resources	46,629	47,556	2.0%
Existing-Other Capacity	4,808	2,313	-51.9%
Prospective Resources	51,437	49,868	-3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.3%	18.0%	-0.3
Prospective Reserve Margin	30.5%	23.7%	-6.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,172	52,195	0.0%
Demand Response: Available	2,932	2,898	-1.2%
Net Internal Demand	49,240	49,297	0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	56,571	60,074	6.2%
Tier 1 Planned Capacity	2,540	1,742	-31.4%
Net Firm Capacity Transfers	300	589	96.3%
Anticipated Resources	59,411	62,405	5.0%
Existing-Other Capacity	847	776	-8.4%
Prospective Resources	60,258	63,181	4.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.7%	26.6%	5.9
Prospective Reserve Margin	22.4%	28.2%	5.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	47,258	46,127	-2.4%
Demand Response: Available	1,946	2,010	3.3%
Net Internal Demand	45,312	44,117	-2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,828	59,559	-0.4%
Tier 1 Planned Capacity	1,514	2,865	89.3%
Net Firm Capacity Transfers	-2,524	-815	-67.7%
Anticipated Resources	58,818	61,609	4.7%
Existing-Other Capacity	859	908	5.7%
Prospective Resources	59,677	62,517	4.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.8%	39.6%	9.8
Prospective Reserve Margin	31.7%	41.7%	10.0
Reference Margin Level	15.0%	15.0%	0.0

SPP			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,040	53,468	2.7%
Demand Response: Available	658	842	27.9%
Net Internal Demand	51,382	52,626	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,245	65,821	-2.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-144	-238	65.0%
Anticipated Resources	67,101	65,583	-2.3%
Existing-Other Capacity	0	0	-
Prospective Resources	66,554	65,036	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.6%	24.6%	-6.0
Prospective Reserve Margin	29.5%	23.6%	-5.9
Reference Margin Level	16.0%	19.0%	3.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	77,317	82,307	6.5%
Demand Response: Available	2,856	3,380	18.3%
Net Internal Demand	74,461	78,927	6.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	89,603	94,580	5.6%
Tier 1 Planned Capacity	1,199	2,445	103.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	90,822	97,045	6.9%
Existing-Other Capacity	0	0	-
Prospective Resources	90,850	97,073	6.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.0%	23.0%	1.0
Prospective Reserve Margin	22.0%	23.0%	1.0
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,228	11,206	-0.2%
Demand Response: Available	0	0	-
Net Internal Demand	11,228	11,206	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,926	13,759	15.4%
Tier 1 Planned Capacity	1,082	227	-79.0%
Net Firm Capacity Transfers	437	0	-100.0%
Anticipated Resources	13,445	13,986	4.0%
Existing-Other Capacity	0	0	-
Prospective Resources	13,445	13,986	4.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.7%	24.8%	5.1
Prospective Reserve Margin	19.7%	24.8%	5.1
Reference Margin Level	10.1%	9.9%	-0.2

WECC-BC			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,088	8,636	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	8,088	8,636	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,266	11,135	-1.2%
Tier 1 Planned Capacity	3	0	-100.0%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,269	11,135	-1.2%
Existing-Other Capacity	0	0	-
Prospective Resources	11,269	11,135	-1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.3%	28.9%	-10.4
Prospective Reserve Margin	39.3%	28.9%	-10.4
Reference Margin Level	16.3%	14.4%	-1.9

WECC-CA / MX			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	57,269	56,356	-1.6%
Demand Response: Available	844	862	2.2%
Net Internal Demand	56,425	55,494	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,791	69,408	-2.0%
Tier 1 Planned Capacity	3,381	5,522	63.3%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	74,172	74,930	1.0%
Existing-Other Capacity	0	0	-
Prospective Resources	74,172	74,930	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.5%	35.0%	3.6
Prospective Reserve Margin	31.5%	35.0%	3.6
Reference Margin Level	16.9%	16.8%	-0.1

WECC-SW			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	26,720	25,992	-2.7%
Demand Response: Available	399	380	-4.7%
Net Internal Demand	26,321	25,612	-2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	28,249	26,206	-7.2%
Tier 1 Planned Capacity	1,369	1,655	20.9%
Net Firm Capacity Transfers	1,002	2,747	174.2%
Anticipated Resources	30,620	30,608	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	30,620	30,608	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.3%	19.5%	3.2
Prospective Reserve Margin	16.3%	19.5%	3.2
Reference Margin Level	10.2%	10.8%	0.6

WECC-NW			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	63,214	66,366	5.0%
Demand Response: Available	1,104	1,038	-6.0%
Net Internal Demand	62,110	65,328	5.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,154	76,587	9.2%
Tier 1 Planned Capacity	798	2,350	194.5%
Net Firm Capacity Transfers	2,517	5,004	98.8%
Anticipated Resources	73,469	83,941	14.3%
Existing-Other Capacity	0	0	-
Prospective Resources	73,469	83,941	14.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.3%	28.5%	10.2
Prospective Reserve Margin	18.3%	28.5%	10.2
Reference Margin Level	16.1%	16.3%	0.2

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (i.e., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	30,373	5,488	18%	7,499	3,750	50%	4,884	4,688	96%
MRO-Manitoba Hydro	259	47	18%	-	-	0%	6,220	5,548	89%
MRO-SaskPower	615	203	33%	30	-	0%	851	797	94%
NPCC-Maritimes	1,212	255	21%	4	-	0%	1,315	1,183	90%
NPCC-New England	1,448	186	13%	2,914	1,163	40%	3,565	2,472	69%
NPCC-New York	2,879	331	12%	179	84	47%	6,731	5,067	75%
NPCC-Ontario	4,943	771	16%	478	126	26%	8,985	5,185	58%
NPCC-Québec	3,880	-	0%	10	-	0%	40,307	32,974	82%
PJM	10,923	1,688	15%	5,169	2,984	58%	3,027	3,027	100%
SERC-Central	1,206	564	47%	885	511	58%	4,967	3,315	67%
SERC-East	-	-	0%	1,475	1,473	99%	3,064	3,013	98%
SERC-Florida Peninsula	-	-	0%	7,724	4,534	59%	-	-	0%
SERC-Southeast	-	-	0%	5,305	4,647	88%	3,242	3,288	101%
SPP	32,028	4,500	14%	440	378	86%	5,465	4,996	91%
Texas RE-ERCOT	30,938	10,293	33%	15,958	12,509	78%	563	477	85%
WECC-AB	3,619	309	9%	1,165	763	65%	894	416	47%
WECC-BC	747	137	18%	2	1	50%	16,519	10,124	61%
WECC-CA/MX	9,362	1,111	12%	21,975	14,489	66%	13,957	4,606	33%
WECC-SW	2,994	593	20%	3,493	1,411	40%	1,202	844	70%
WECC-NW	20,296	3,968	20%	9,270	5,062	55%	41,860	22,752	54%
EASTERN INTERCONNECTION	85,886	14,032	16%	32,102	19,649	61%	52,316	42,578	81%
QUÉBEC INTERCONNECTION	3,880	-	0%	10	-	0%	40,307	32,974	82%
TEXAS INTERCONNECTION	30,938	10,293	33%	15,958	12,509	78%	563	477	85%
WECC INTERCONNECTION	37,018	6,118	17%	35,905	21,726	61%	74,432	38,742	52%
INTERCONNECTION TOTAL:	157,722	30,443	19%	83,975	53,885	64%	167,618	114,771	68%

Probabilistic Assessment

Regional Entities and assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are included in the Highlights section of each assessment area's dashboard and summarized in the table below. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincide with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of EEA occurrence.

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
MISO	Annual probabilistic LOLE study	MISO's RML decreased from 17.9% in 2022 to 15.9% for Summer 2023. The change results from implementing seasonal forced outages and probabilistic distributions of non-firm imports. Operating mitigations are needed in extreme peak summer conditions.
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results indicate 29 MWh per year of EUE for 2024. Given comparable supply and demand balance, the 2024 EUE is a reasonable estimate for all of 2023. EUE for summer is less than the annual EUE.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2023 summer season (June to September) is 0.21 hours. September is the month with highest risk.
NPCC	NPCC conducted an all-hour Probabilistic Assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	The assessment forecasts that the NPCC Regional Entity will have an adequate supply of electricity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Results of the probabilistic analysis by assessment area are below.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes is likely to use a combination of imports and operating procedures to mitigate resource shortages this summer. Cumulative LOLE (<0.03 days/summer), LOLH (<0.11 hours/summer), or EUE (<5 MWh/summer) were estimated over the May–September summer for all modeled scenarios.
NPCC-New England		NPCC's assessment results indicate that ISO-NE may rely on limited use of its operating procedures to mitigate resource and energy shortages during the summer. The reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.12 days/period) with associated LOLHs (0.4 hours/period) and EUE (175 MWh/period) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.
NPCC-New York		NPCC's assessment results indicate that NYISO may rely on limited use of its operating procedures to mitigate resource and energy shortages during the summer. The reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.5 days/summer) with associated LOLH (1.1 hours/summer) and EUE (525 MWh/summer). The highest risk is in June and August.
NPCC-Ontario		NPCC's assessment results indicate that Ontario is likely to use a combination of imports and operating procedures to mitigate resource shortages this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases. These results indicate that Ontario will be able to obtain necessary supplies from neighbors over a range of conditions.

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
NPCC-Québec		Québec is expected to need only limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
PJM	Based on 2022 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 29% installed reserve margin, well above the target of 14.9%. Due to the low penetration of variable energy resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand.
SERC	Verification of NERC 2022 ProbA Results	The 2022 Base Case results indicated adequate resources for the SERC Region as a whole with an observed LOLE of 0.03 days/year for the year 2024. Trends from 2022 to 2023 indicate little change in study results, so SERC does not anticipate resource adequacy risk for the upcoming summer season.
SERC-Central		Probabilistic analysis indicates no risk for resource shortfall.
SERC-East		Probabilistic analysis shows low risk for July and August with EUE of 2.38 MWh and LOLH 0.005 hours.
SERC-Florida Peninsula		SERC Probabilistic analysis indicates no risk of resource shortfall.
SERC-Southeast		Probabilistic analysis indicates almost no risk of resource shortfall.
SPP	Statistical analysis of the Summer 2022 real time data; Operational process and procedures	Potential risk of using operating reserves and EEA1 or EEA2 is 1 day per summer. Risk of EEA3 is 0.2 days per summer. Risks is associated with low wind generation output levels or unanticipated generation outages in combination with high load periods.
Texas RE-ERCOT	ERCOT's Summer 2023 Probabilistic Assessment	There is a 4% probability that ERCOT will declare an EEA1 during the expected daily peak load hour; Increasing up to 19% probability at the highest risk hour and ending at 8:00 p.m.
WECC	The 2022 Western Assessment of Resource Adequacy provides the most recent probability-based resource adequacy risk assessment for Summer 2023 across WECC's areas.	The Western Interconnection is experiencing heightened reliability risks heading into Summer 2023 due to increased supply-side shortages and fuel constraints along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events. The installation of new resources for the summer and the availability of the imports, especially during wide-area heat events, affects resource adequacy for the U.S. assessment areas. The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint.
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-BC		BC is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-CA/MX		WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<0.5 hours) this summer with variation attributable to the amount of Tier 1 resources that connect before the later months. Resources are sufficient to meet demand and cover reserves on the peak hour at 3:00

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
		p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates. However, there is increased risk of insufficient reserves at later hours (up to 8:00 p.m.) due to the variability of energy resource output. Imports to the area are required to cover these risk periods; however, regional resource availability and transmission constraints can affect external assistance during wide area heat events.
WECC-NW		WECC-NW assessment area is projected to have negligible LOLH and EUE this summer with planned resource additions and normal transfer availability. However, some LOLH (<0.1) and EUE (<400 MWh) is anticipated during above-normal demand periods if new resource are delayed or external transfers are disrupted. WECC-NW would rely on imports to maintain adequate reserves on the during the risk hours from 4:00–9:00 p.m. under extreme summer peak load and low-resource conditions (e.g., extreme thermal or extreme hydro derates or combinations of other low energy output scenarios.)
WECC-SW		WECC-SW assessment area is projected to have negligible LOLH and EUE this summer with planned resource additions and normal transfer availability. However, some LOLH (<0.1) and EUE (<150 MWh) is anticipated during above-normal demand periods if new resource are delayed or external transfers are disrupted.

Errata

May 2023

- The Risk Scenario Summaries for SERC-Central and SERC-East were corrected (page 23 and page 24)

2024 Summer Reliability Assessment

May 2024

Table of Contents

Preface

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

Reliability | Resilience | Security

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

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

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

About this Assessment

NERC's *2024 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2023 Long-Term Reliability Assessment (LTRA*), covering a 10-year horizon*,* and other earlier reliability assessments and reports.[1]

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for the 2024 summer.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar photovoltaic (PV) energy conditions:

- **Midcontinent Independent System Operator (MISO):** New solar and natural-gas-fired generation and additional demand response (DR) resources are offset by generator retirements, lower firm imports, and increased reserve requirements. MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand. However, it can be challenging for MISO to meet above-normal peak demand if wind and solar resource output is lower than expected. Wind generator performance during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system or if external (non-firm) supply assistance is required to maintain reliability.
- **MRO-SaskPower:** Despite being primarily a winter-peaking area, Saskatchewan can face high electricity demand during hot summer weather conditions. Since 2023, both electricity demand and supply resources have increased, resulting in a 1.2% increase in reserve margin for the summer. Unanticipated generator outages that coincide with peak demand can result in insufficient reserves, a condition that operators will seek to alleviate through short-term transfers from neighbors and demand-side management.
- **NPCC-New England:** With the retirement of two natural-gas-fired generators at Mystic Generating Station in May 2024 (1,400 MW combined summer capacity), ISO New England will have less capacity this summer. This makes it more likely that ISO New England will need to resort to operating procedures for obtaining resources or non-firm supplies from neighboring areas during periods of above-normal peak demand or low-resource conditions. Summer heat waves that extend over the entire area can limit the availability of excess supplies and increase the risk of energy emergencies in New England.
- **Texas RE-ERCOT:** As a result of continued vigorous growth in both loads and solar and wind resources, there is a risk of emergency conditions in the summer evening hours when solar generation begins to ramp down. Contributing to the elevated risk is a potential need, under certain grid conditions, to limit power transfers from South Texas into the San Antonio region. These grid conditions can occur when demand is high and wind and solar output is low in specific areas, straining the transmission system and necessitating South Texas generation curtailments and potential firm load shedding to avoid cascading outages.
- **WECC-BC:** The peak demand forecast in the province of British Columbia has increased by over 600 MW since 2023 (7.4%), contributing to a drop in Anticipated Reserve Margin by over 10 percentage points. Much of the province is experiencing significant drought, and long-term precipitation deficits can challenge electricity production at some hydropower generators. Above-normal demand and low-resource conditions can result in the need for imports from neighboring areas. However, external assistance can be at risk during wide-area heat events.
- **WECC-CA/MX:** New solar and battery resources are contributing to higher on-peak reserve margins (46.7%, up over 11 percentage points since 2023) for the upcoming summer. Winter precipitation and snowpack have alleviated drought conditions across California, making more output from the area's hydropower resources available to balance variability in wind and solar output. Probabilistic assessments performed by WECC show that the risks of load loss are similar to Summer 2023, ranging from negligible to 0.8 loss of load hours (LOLH) depending on how much of the area's new solar and battery resources (totaling nearly 6 GW of nameplate capacity) are completed over the summer. The loss-of-load risk in this analysis occurs primarily under above-normal demand and low-resource conditions (e.g., low solar output, below-normal imports due to wide-area heat conditions or transmission limitations). Furthermore, risk is concentrated in the Baja (Mexico) portion of the WECC-CA/MX

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

assessment area. The assessment area has adequate resources for normal summer conditions.

- **WECC-SW:** Both forecasted peak demand and resources have risen since last summer, yielding a modest increase in the anticipated on-peak reserve margin (22.0%, up 2.5 percentage points since 2023.) The area has sufficient resources for normal summer demand. However, extreme demand or low resource output scenarios will likely require additional non-firm imports from neighboring areas, which may be unavailable during wide-area heat events. The ongoing severe drought in the Southwest increases the risk that extreme conditions could impact the BPS this summer.

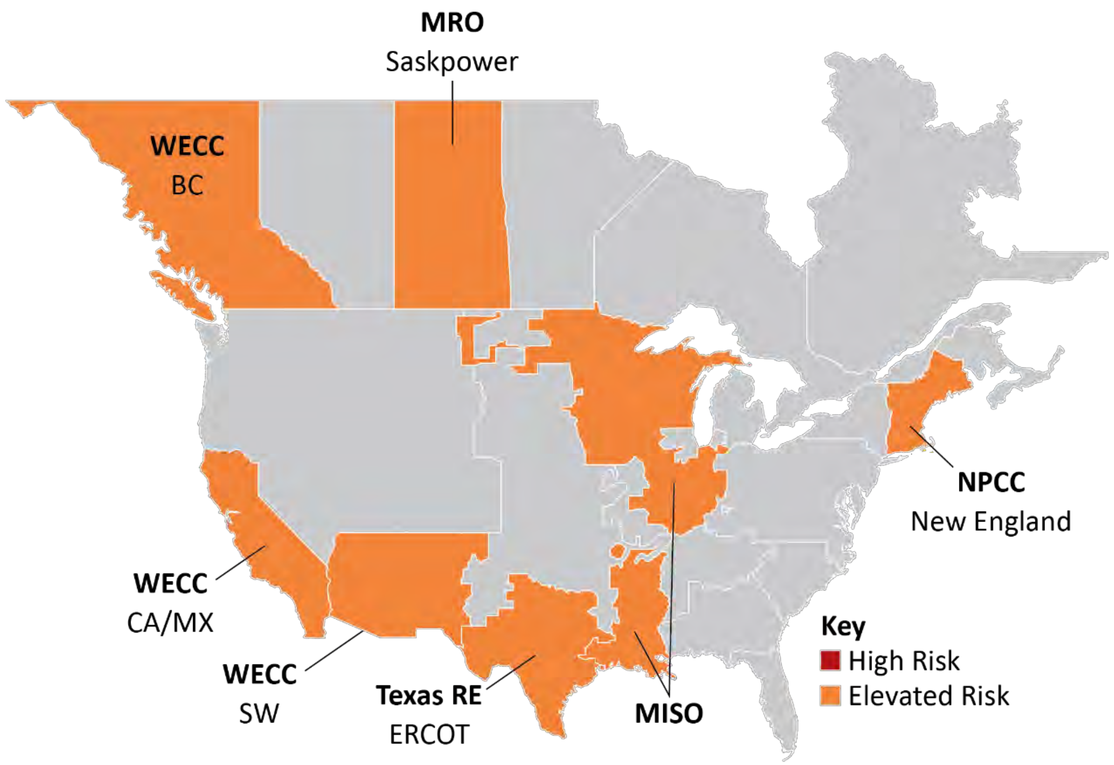


Figure 1: Summer Reliability Risk Area Summary

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

New resources including 25 GW of nameplate solar capacity have been added to the BPS since last summer. Resource additions in assessment areas that were identified as at risk in the *2023 SRA* have largely outpaced rising demand forecasts and resulted in higher on-peak reserve margins. Four elevated-risk assessment areas from the *2023 SRA* are considered normal risk for the upcoming summer: NPCC-Ontario, SERC-Central, SPP, and WECC-NW. New firm transfer agreements, growth in DR, and postponed generator retirements are also contributing to an overall improved resource outlook for the upcoming summer. Details of each area are contained in the assessment area pages.

The findings in the *SRA* are consistent with conclusions reported in NERC's *2023 LTRA*. In assessing potential future electricity supply shortfalls over the 10-year horizon, NERC found that resource additions and delayed generator retirements have improved the outlook for 2024 in comparison to results reported in prior *LTRA*s. However, the *2023 LTRA* also found that a growing number of areas in North America face adequacy risks as early as 2025. NERC will publish the next *LTRA* in December 2024 based on demand forecasts, resource and transmission projections, and other information collected this year. NERC will also publish the 2024–2025 *Winter Reliability Assessment* in November to identify, assess, and report on BPS reliability issues for the next winter season.

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America, potentially creating challenging summer grid conditions.** Peak electricity demand in most areas is directly influenced by temperature. Above-average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Last summer brought record temperatures, extended heat waves, and wildfires to large parts of North America. Although few high-level energy emergency alerts were issued and no electricity supply disruptions occurred as a result of inadequate resources, operators at BAs, TOPs, and RCs faced significant challenges and drew upon procedures and protocols to obtain all available resources, manage system demand, and ensure that energy is delivered over the transmission network to meet the system demand. Additionally, load-serving entities and state and local officials in many parts of North America used mechanisms and public appeals to lower customer demand during periods of strained supplies. Operators should review lessons and experience from the prior summer and incorporate insights into their seasonal operations planning. The **Review of 2023 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2023 SRA* and summarizes 2023 resource adequacy events.

- **Rising demand is challenging resource and transmission adequacy in several areas.** Most areas are forecasting increases in peak demand compared to last summer. The extent that demand forecasts have increased and the drivers affecting growth vary by area. In ERCOT, SPP, and British Columbia, the increases are among the highest and build on similar growth from the prior year. New data centers and cryptocurrency mining facilities are contributing to higher demand forecasts in ERCOT this summer, and some of these loads participate in demand-side management programs that can offset their impacts (see **Evolving Demand-Side Management Programs**). While resource additions in Texas, primarily solar PV, are outpacing demand increases, energy risks are growing during the hours when solar output is diminished. Further, transmission development is straining to connect new resources and deliver electricity supplies to growing load areas.

- **Occurrences involving the unexpected tripping of inverter-based resources (IBR) during grid disturbances continue to spread, underscoring the need for operator vigilance in the near term and urgent industry action on long-term solutions.** The tripping of BPS-connected solar PV generating units during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California. Similar events have occurred as recently as Summer 2023.[2] New event reports published by NERC analyzing the Southwest Utah disturbance (April 2023) and the California Battery Energy Storage disturbances (April and May 2022) illustrate that the reliability concern extends to more geographic areas and more than just solar PV resources. IBRs include most solar and wind generation as well as new battery energy storage systems (BESS) or hybrid generation and account for over 70% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. A common thread with these tripping events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. In March 2023, NERC issued the *Inverter-Based Resource Performance Issues Alert* to Generator Owners (GO) of Bulk Electric System (BES) solar PV generating resources.[3] As a Level 2 alert, it contains recommended actions for GOs of grid-connected solar PV resources, including steps to coordinate protection and controller settings, so that the resources will remain reliable during grid disturbances. NERC's comprehensive Inverter-Based Resources Strategy and FERC Order No. 901 describe additional steps for the ERO and industry to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[4,5]
- **Stored supplies of natural gas are at high levels, but continued vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.**[6] The natural gas supply and infrastructure is vitally important to electric grid reliability, particularly as variable energy resources satisfy more of our energy needs. Fuel supply and delivery infrastructure must be capable of meeting the ramp rates of natural-gas-fired generators as they balance the system when wind and solar generation output declines. No specific reliability issues have been identified for the upcoming summer, but Reliability Coordinators (RC) and Balancing Authorities (BA) should be cognizant of natural gas supply infrastructure outage and maintenance plans that could affect generators in their areas.
- **Expanded demand-side management programs are an added resource for operators that should be carefully considered in operating plans and monitored during peak demand periods.** Formal DR programs involving commercial and industrial customers that have agreements with their load-serving entities to curtail load during high-demand periods have grown in many assessment areas. Additionally, some entities have launched programs with retail customers that also provide operator-controlled demand-side management capabilities. Operators will need to give special attention to new or expanded demand-side management programs in their planning if they are unfamiliar with protocols or uncertain about the amount of load relief that will be realized. These new mechanisms and protocols for controlling demand can support operating reliability and energy adequacy needs when they are effectively implemented and monitored.
- **Supply chain issues are delaying some new resource and transmission projects, raising concerns that some may not be completed prior to peak summer conditions.** Lead times for transformers, circuit breakers, transmission cables, switchgears, and insulators have increased significantly since 2020. Additionally, PV panels are more difficult to procure. These longer lead times can affect new project construction, existing asset upgrades, pre-seasonal maintenance, and the interconnection of new resources and customers. Long-term mitigation strategies include lengthening ongoing construction timelines and ordering surplus inventory in advance. In the near term, supply chain issues can exacerbate concerns in elevated risk areas and add operating challenges for the summer across the BPS. Should project delays emerge, affected GOs and Transmission Owners (TO) must communicate changes to BAs, Transmission Operators (TOP), and RCs so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.
- **Wildfire risk areas cover a smaller portion of North America at the start of summer, lowering the likelihood that the BPS will be affected by fire conditions.** At the start of summer, Canadian wildfire information system officials assess that there is potential for above-average fire activity over a large region that extends from British Columbia to northwest Manitoba

[2] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[3] NERC Alert: Inverter Based Resource Performance Issues
[4] NERC IBR Activities
[5] FERC Order No. 901 - Final Rule Reliability Standards to Address Inverter-Based Resources
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)

and includes Alberta and Saskatchewan. In the United States, Climate Prediction Center and Predictive Services outlooks for early summer indicate that above-normal significant fire potential is limited to portions of the U.S. Southwest and West Texas.[7] Nonetheless, wildfire risk in North America typically increases in later summer months as hotter and drier weather increases fire potential. BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels
  - Employ conservative generation and transmission outage coordination procedures commensurate with long-range weather forecasts to ensure adequate resource availability
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[8]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department of Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[7] NIFC North American Outlook

[8] Industry Recommendation: Inverter-Based Resource Performance Issues

Discussion

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above-normal temperatures for much of the United States and Canada (see **Figure 2**). In addition, drought conditions continue across much of Canada and the U.S. Southwest, resulting in unique challenges to area electricity supplies and potential impacts on demand.[9] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above-average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

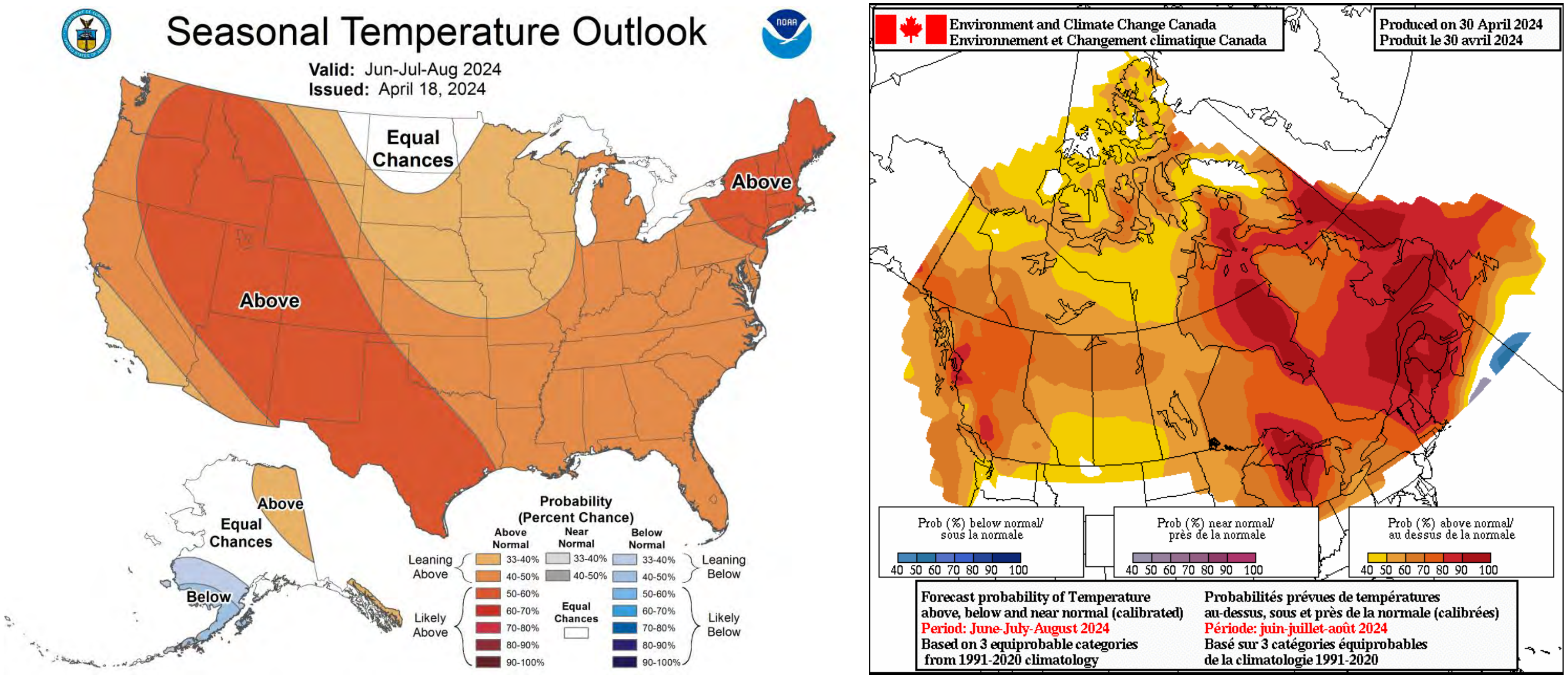


Figure 2: United States and Canada Summer Temperature Outlook[10]

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[9] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

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

Table 1: Seasonal Risk Assessment Summary

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

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

Assessment of Planning Reserve Margins and Operational Risk Analysis

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

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	26.1%	8.7%	-6.3%
MRO-Manitoba	15.7%	11.7%	5.1%
MRO-SaskPower	30.3%	26.5%	10.3%
MRO-SPP	27.8%	17.6%	-2.5%
NPCC-Maritimes	44.9%	34.5%	6.0%
NPCC-New England	15.9%	6.3%	3.3%
NPCC-New York	30.4%	11.4%	4.0%
NPCC-Ontario	26.2%	26.2%	19.8%
NPCC-Québec	44.1%	23.8%	18.2%
PJM	27.6%	17.9%	9.0%
SERC-C	24.3%	14.9%	14.7%
SERC-E	22.2%	16.3%	10.8%
SERC-FP	26.3%	19.3%	12.3%
SERC-SE	44.6%	41.1%	34.9%
TRE-ERCOT	25.6%	19.2%	11.5%
WECC-AB	30.5%	28.1%	8.6%
WECC-BC	18.8%	18.7%	-5.6%
WECC-CA/MX	46.7%	40.8%	5.4%
WECC-NW	35.5%	29.7%	1.1%
WECC-SW	22.0%	12.9%	-10.8%

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

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's 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.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section's discussion. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the 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.

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

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2024. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required 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.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results found 187 MWh EUE for Summer 2024 and <1 hour of LOLH. However, MISO has more resources and higher reserves for the summer than were considered in the 2022 ProbA, which should result in lower risk.
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results indicate 29 MWh per year of EUE for 2024.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2024 summer season (June–September) is 0.68 hours. June is the month with highest risk.
MRO-SPP	Statistical analysis of the Summer 2022 real-time data and operating procedures	Potential risk of using operating reserves and EEA 1 or EEA 2 is 1 day per summer. Risk of EEA3 is 0.2 days per summer. Risk is associated with low wind generation output levels or unanticipated generation outages in combination with high-load periods.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. [NPCC anticipates releasing the assessment in early May].
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
NPCC-New England		NPCC's assessment results indicate that ISO-New England (ISO-NE) could experience resource shortages during high-demand and low-resource conditions and require limited use of operating procedures for mitigation. In NPCC's probabilistic assessment, the reduced resource case with the highest peak load scenario resulted in New England having a small estimated cumulative LOLE risk (0.66 days/summer) with associated LOLHs (2.7 hours/summer) and EUE (1,476 MWh/summer) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low-resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM. Negligible cumulative LOLE (<0.022 days/summer), LOLH (<0.08hours/summer), and EUE (<17 MWh/summer) risks were estimated over the summer May–September period for the other scenarios modeled.
NPCC-New York		NPCC's assessment results indicate that New York ISO (NYISO) could experience resource shortages during high-demand conditions and require limited use of operating procedures for mitigation. In NPCC's probabilistic assessment, the highest peak load scenarios resulted in New York having a small estimated cumulative LOLE risk (1.6 days/summer) with associated LOLHs (5.9 hours/summer) and EUE (5,460 MWh/summer) with the highest risk occurring in July and August. Scenarios are based exclusively on the two highest load levels with a 7% chance of occurring. Negligible cumulative LOLE (<0.023 days/summer), LOLH (<0.07 hours/summer), and EUE (39 MWh/summer) were estimated over the summer period for the other scenarios modeled. Furthermore, the New York State Reliability Council conducts an annual study to determine the installed reserve margin (IRM) necessary to meet the 1 day in 10 years Loss of LOLE criterion. NYISO has procured capacity for the upcoming summer to meet the IRM requirement.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's assessment results indicate that Ontario is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. In NPCC's probabilistic assessment, the reduced resource case with the highest peak load scenario resulted in Ontario having a negligible cumulative LOLE risk (0.03 days/summer) with associated LOLHs (0.07 hours/summer) and EUE (33 MWh/summer) with the highest risk occurring in August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low-resource case consisting of additional summer maintenance and low hydroelectric output. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer for the other scenarios modeled.
NPCC-Québec		NPCC's assessment results indicate that Québec is unlikely to experience resource shortages that would require additional imports or operating procedures this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
PJM	Based on 2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 29% IRM, well above the target of 17.7%. The RRS analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the low penetration of variable energy resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand.
SERC	Verification of NERC 2022 ProbA Results	The 2022 base case results indicated adequate resources for the SERC Regional Entity as a whole with an observed LOLE of 0.01 days/summer for 2024.
SERC-Central		Probabilistic analysis indicates no risk for resource shortfall.
SERC-East		Probabilistic analysis shows low risk for July and August with EUE of 2.38 MWh and LOLH 0.005 hours.
SERC-Florida Peninsula		SERC probabilistic analysis indicates no risk of resource shortfall.
SERC-Southeast		Probabilistic analysis indicates almost no risk of resource shortfall.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates an elevated risk of having to declare an EEA during evenings on peak load days in August—the forecasted summer peak load month. The probability of declaring an EEA is 18.4% during the highest risk hour. The probability of firm load shedding is 14.6% during the highest risk hour. The model accounts for the risk of triggering the curtailment of coastal region wind generation due to transmission system constraints.
WECC	WECC performed a probabilistic assessment for Summer 2024 based on demand and resource forecasts provided by load-serving entities.	Resource adequacy remains a critical risk in the Western Interconnection and continues to challenge industry planners, operators, regulators, and partners. Resource adequacy risks over the medium and long terms have increased significantly compared to last year's assessment. Three risks merit particular attention: increasing variability, rate of demand growth and uncertainty of future load patterns, and the pace of new resource growth necessary to meet future energy demand.[11]
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 5:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.

[11] See 2023 Western Assessment of Resource Adequacy.pdf (wecc.org)

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-BC		British Columbia is expected to have sufficient resource availability to meet reserves at the peak demand hour (5:00–6:00 p.m.) under most conditions. However, above-normal demand that coincides with low hydro output could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates including low hydro output.
WECC-CA/MX		WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<1 hours) this summer, primarily forecast in the Baja (Mexico) part of CA/MX. Resources are sufficient to meet demand and cover reserves on the peak demand hour at 5:00 p.m. under a summer peak demand defined at the 90th percentile with any combination or accumulation of resource derates. There is increased risk of insufficient reserves at later hours (up to 7:00 p.m.) due to the variability of energy resource output. Imports to the area are required to cover these risk periods.
WECC-NW		The Northwest is expected to have sufficient resource availability to meet reserves at the peak demand hour at 5:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-SW		Results of WECC's probabilistic analysis indicate that the WECC-SW assessment area is projected to have negligible LOLH and EUE this summer under assessed scenarios. NERC's assessment of elevated risk is influenced by the deterministic risk scenario on page 36. The scenario shows that the assessment area would have insufficient resources to meet operating reserve requirements at a 90/10 demand level with typical generation outages and a scenario involving low-resource output and normal peak demand.

Evolving Demand-Side Management Programs

Demand-side management programs are expanding in many assessment areas, providing operators with additional resources to reduce electricity demand during periods when electricity supplies may not be sufficient. Figure 3 shows the assessment areas with a DR exceeding 1.5% of the total internal demand. Formal DR programs involving commercial and industrial customers that have agreements with their load-serving entities to curtail load during high demand periods have grown in many assessment areas (see Demand and Resource Tables). Additionally, some entities have launched programs with retail customers that provide similar operator-controlled demand-side management capabilities. Programs in use by the independent system operators in Texas and the province of Ontario, discussed below, provide examples of the types of DR programs in use this summer and the contributions to meeting operating reliability and resource adequacy needs.

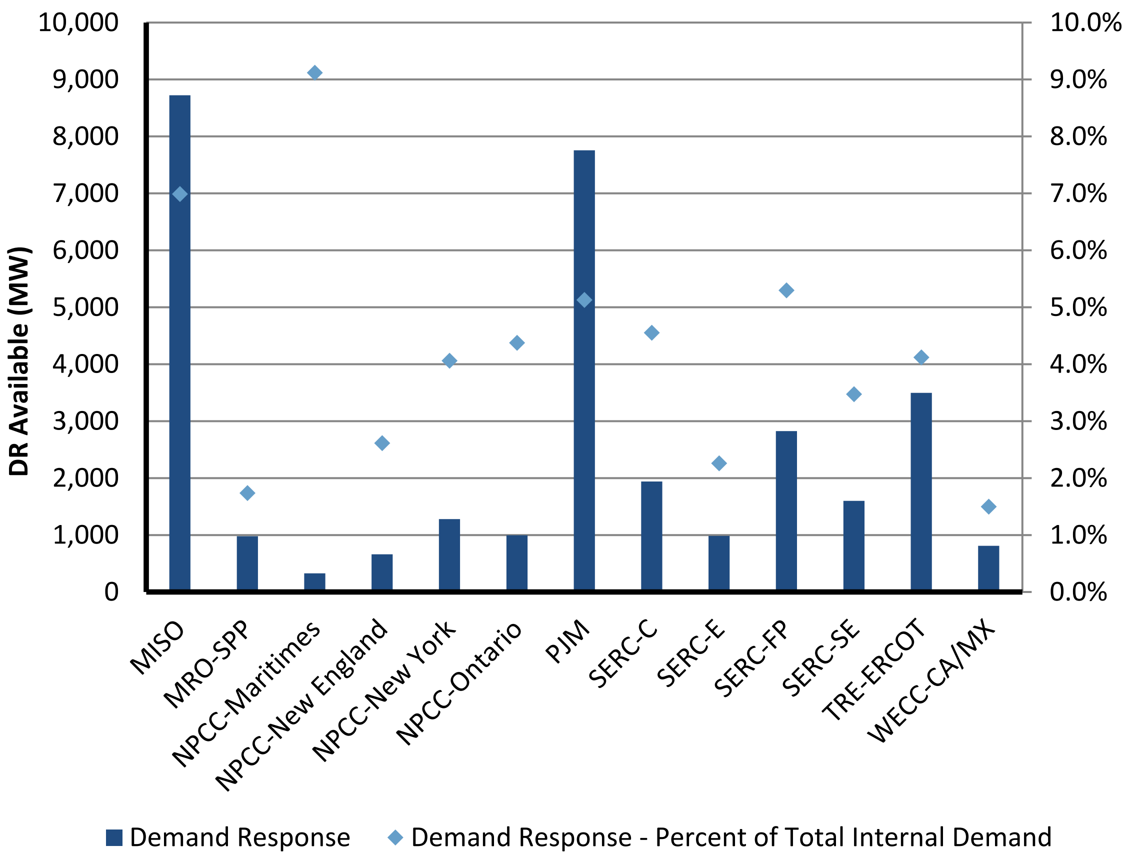


Figure 3: Demand Response in Assessment Areas Exceeding 1.5% Total Internal Demand

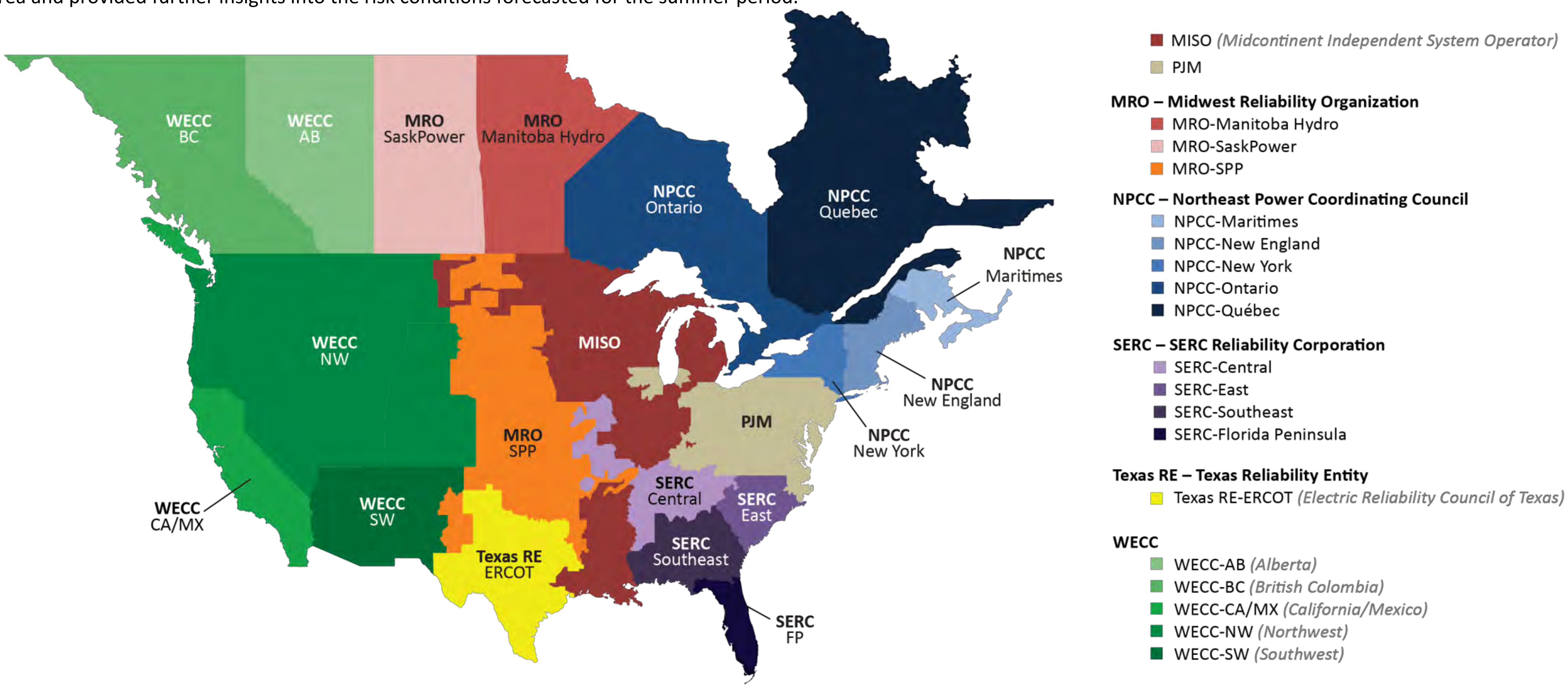
In ERCOT, nearly 3,500 MW of DR resources are expected for this summer, the equivalent of 4% of normal peak demand. Resources come from various programs, including several that are administered by ERCOT as well as those administered by other entities.

- ERCOT's controllable load resources (CLR) consist of large loads (e.g., data centers) and battery charging systems that can be dispatched by ERCOT to provide frequency regulation and short-notice resources for managing wind and solar ramps; 600 MW of CLRs are registered.
- Non-controllable load resources (NCLR) consist of "blocky" loads with both a 10-minute ramp capability for manual deployments and automatic deployment through underfrequency relay. NCLRs participate in ERCOT's Responsive Reserve Service market. ERCOT expects just over 1,100 MW of participation for the highest reserve risk hours for the upcoming summer.
- Some DR resources participate in ERCOT's Emergency Response Service (ERS), along with distributed generation. ERCOT's ERS consists of 10- and 30-minute-ramping DR and distributed generation that can first be deployed when physical responsive capability (PRC) drops to 3,000 MW to provide a contingency reserve. During the 2023 program year, ERS was deployed twice, once on August 17, and again on September 6 when ERCOT's PRC dropped below 3,000 MW. ERCOT expects approximately 1,000 MW to participate in ERS for the highest reserve risk hours for the upcoming summer.
- Transmission and distribution service provider (TDSP) load management programs provide price incentives for voluntary load reductions from commercial, industrial, and, most recently, residential loads during EEA Level 2 events. These programs have historically only been available for the months of June through September from 1:00–7:00 p.m. on weekdays (except holidays) and deployed via ERCOT instruction pursuant to agreements between ERCOT and the TDSPs. ERCOT forecasts that these programs can provide 330 MW in demand relief this summer. In addition, ERCOT Nodal Protocols allow ERCOT to instruct TDSPs to reduce customer load by using existing, in-service distribution voltage reduction measures to avoid an EEA. Conservation voltage reduction (CVR) can lower demand by nearly 575 MW.
- ERCOT accounts for load-reduction programs administered by retail entities in its load forecast. The 4-Coincident Peak (4CP) Load Reduction program incentivizes customers to reduce load during four anticipated 15-minute peak-load intervals, one each across the summer months of June, July, August, and September. The amount of load reduction for the four 4CP days in 2023 averaged 4,674 MW. Additionally, retail entities offer a variety of price-response programs that are factored into ERCOT's load forecast.

In the province of Ontario, the Independent Electricity System Operator (IESO) has expanded DR programs for summer. Overall, this summer, the effective capacity of Ontario's DR programs is 996 MW, the equivalent of 4% of normal peak demand. This includes 805 MW of DR from the capacity auction. The Peak Perks program, launched in June 2023, will contribute 92 MW of effective capacity this summer through enrolled residential customers with smart thermostats that may be controlled at peak times. The IESO also launched the Interruptible Rate Pilot in July 2023. The pilot is designed to provide large-load customers with an interruptible rate in exchange for agreeing to interrupt demand during up to 15 event periods, each up to four hours long. The pilot will run for a three-year period and has two participants that will provide 76 MW of interruptible demand.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer 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 *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

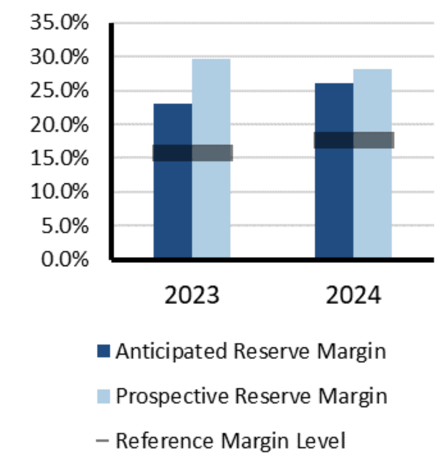
Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's resources are projected to be higher than in Summer 2023 while net internal demand decreased slightly. With increased resource availability for this summer, Anticipated Reserve Margin (ARM) of 31.6% (on an installed capacity basis) is higher than last summer's ARM of 23%.
- MISO conducted its annual probabilistic LOLE analysis and determined that a 2024 Reference Margin Level (RML) of 17.7% results in an LOLE of 1 day in 10 years. MISO's RML increased from 15.9% in 2023 to 17.7% in 2024 based on the summer seasonal capacity construct. A methodology change in the Planning Resource Auction (PRA) requesting GOs' seasonally corrected Generator Verification Test Capacity (GVTC), updated seasonal forced outage rates, and updated annualized planned maintenance outage rates as well as information on new units, retirements, suspensions, and changes in the resource mix contributed to the increase in reserve margin for the 2024 summer. Comparing the increased ARM to the lower RML indicates improved reliability from the LOLE base case at 1 day in 10 years.
- Performance of wind generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum-generation declarations and energy emergencies. MISO has over 31,000 MW of installed wind capacity; however, the historically based on-peak capacity contribution is 5,616 MW.

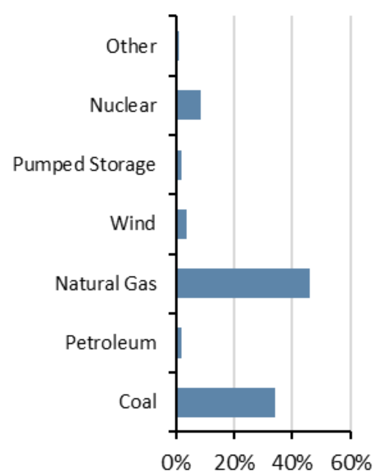
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (DR) when operating reserve shortfalls are projected.

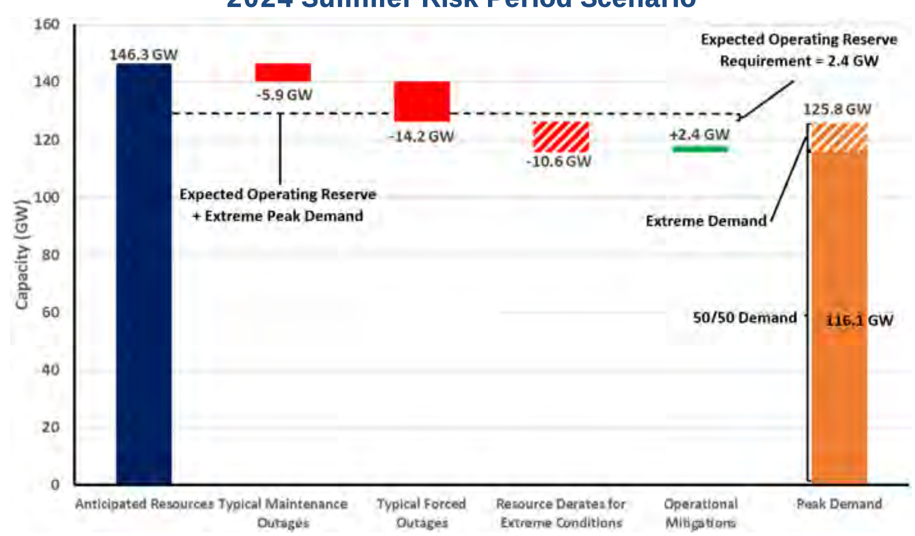
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer 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 summer average of maintenance and planned outages

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

Extreme Derates: Maximum historical generation 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 and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

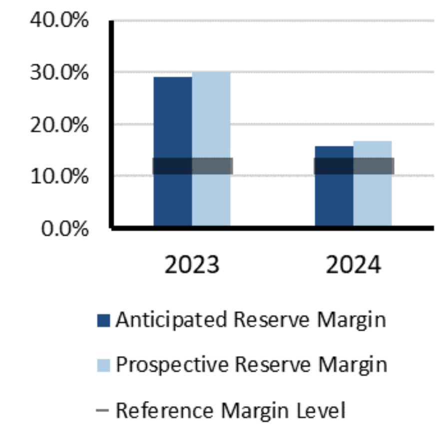
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues for Summer 2024.
- ARM has fallen since Summer 2023 due to higher peak demand forecast, more generator planned maintenance outages, and an increase in net firm capacity transfers. Nonetheless, ARM exceeds the 12% RML.
- Manitoba Hydro is experiencing below-average water supply conditions. However, above-average late-winter snowfall will favorably impact spring runoff. The Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations even if drought continues through 2024/25.
- All units at Keeyask Generating Station have commercial operation status.

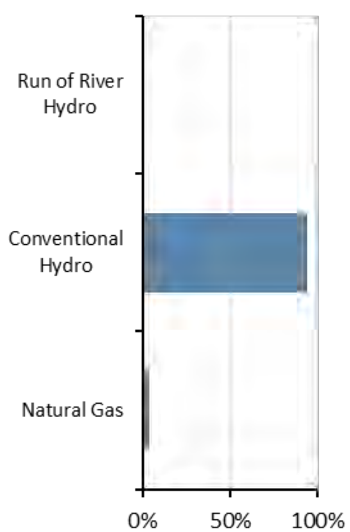
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

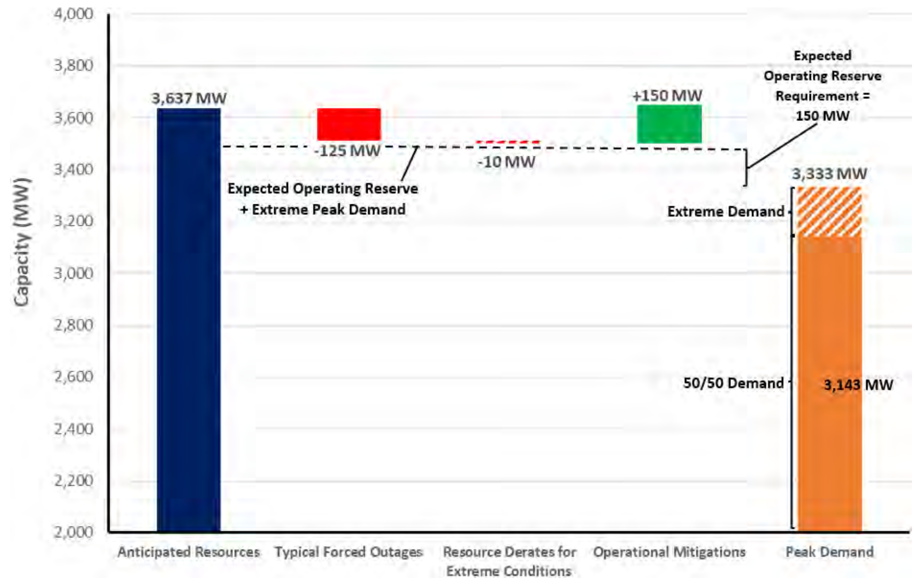
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

MRO-SaskPower

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

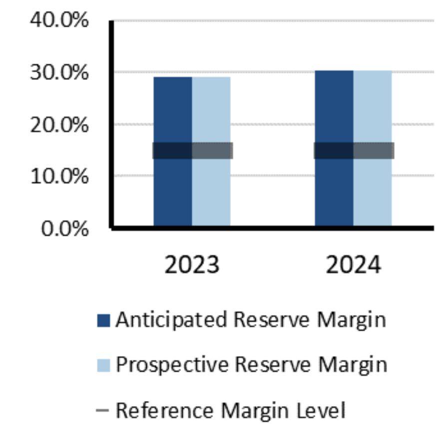
Highlights

- Despite being primarily a winter-peaking area, Saskatchewan also faces significant electricity demand in the summer during extremely hot weather conditions.
- SaskPower collaborates annually with Manitoba Hydro for a summer joint operating study, incorporating inputs from the Western Area Power Administration (WAPA) and Basin Electric to develop operational guidelines addressing any identified issues.
- The probability of experiencing a shortage in operating reserves during peak load periods, or EEAs, may increase if significant generation forced outages happen at the same time as planned maintenance outages during the high-demand months of June through September.
- If extreme thermal conditions align with significant generation outages, SaskPower will deploy available DR programs, engage in short-term power transfers from neighboring utilities, and implement temporary load interruptions as necessary to mitigate the situation.

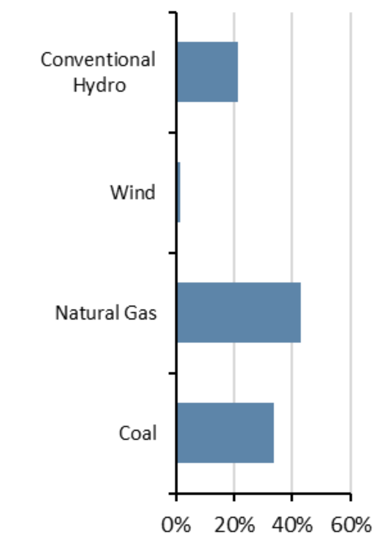
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Above-normal summer peak load and outage conditions similar to those observed in Summer 2023 are likely to result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

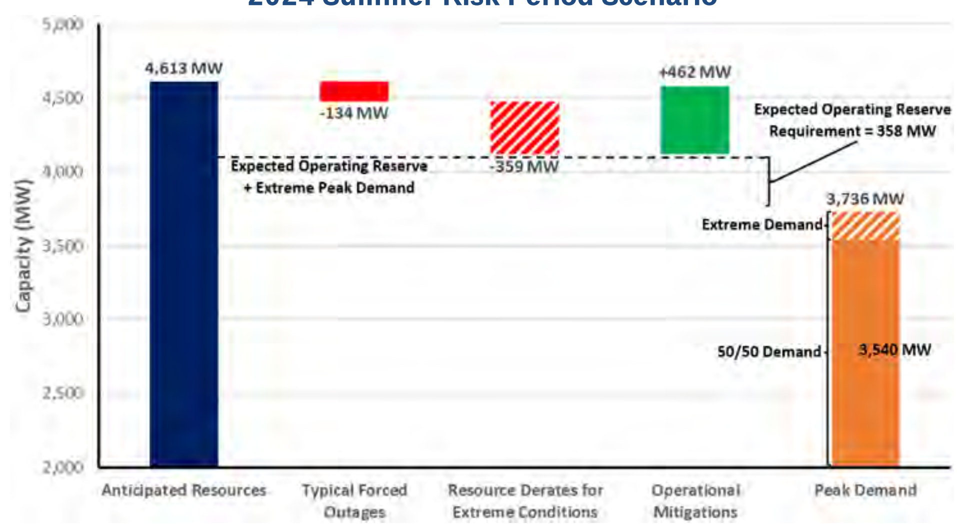
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer 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

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice

MRO-SPP

SPP PC’s footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Highlights

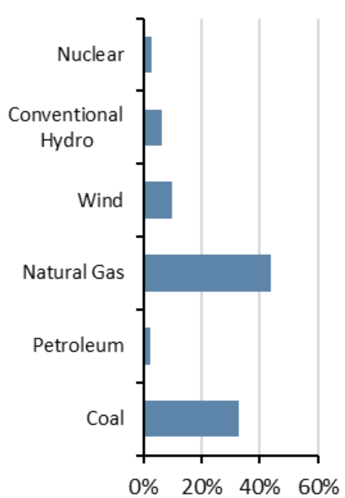
- ARMs are higher in SPP compared to Summer 2023. Increased capacity for the summer is coming from wind resource additions, higher expected wind contribution at peak demand, and commitments from switchable generators (i.e., resources capable of supplying SPP or a neighboring BA) to qualify as resources in SPP.
- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2024 summer season.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high-load periods.
- Using the current operational processes and procedures, SPP will continue to assess the needs for the 2024 summer season and will adjust as needed to ensure that real-time reliability is maintained throughout the summer time frame.

Risk Scenario Summary

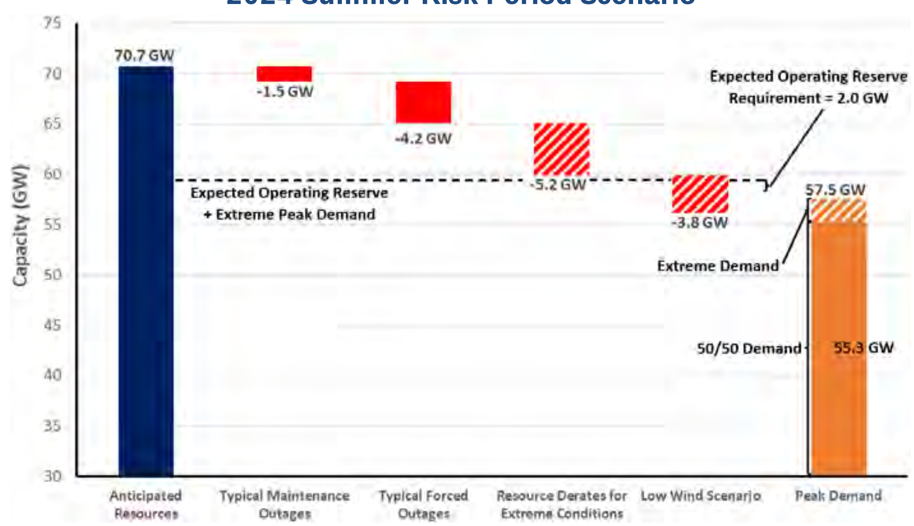
Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could necessitate operating mitigations (e.g., DR and transfers from neighboring systems) and EEAs.

On-Peak Reserve Margin

On-Peak Fuel Mix



2024 Summer 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 is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP’s generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

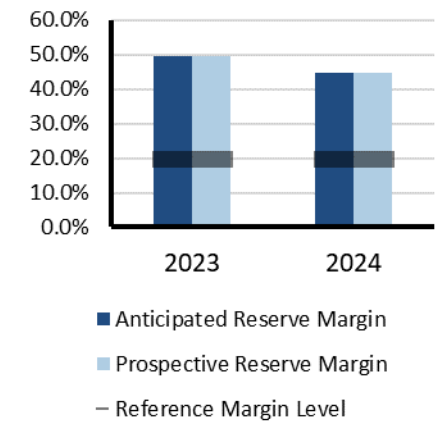
NPCC-Maritimes

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

Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were to occur, emergency operations and planning procedures are in place.
- All of the area's declared firm capacity is expected to be operational for the summer operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to enable sustained operation in the event of natural gas supply interruptions.

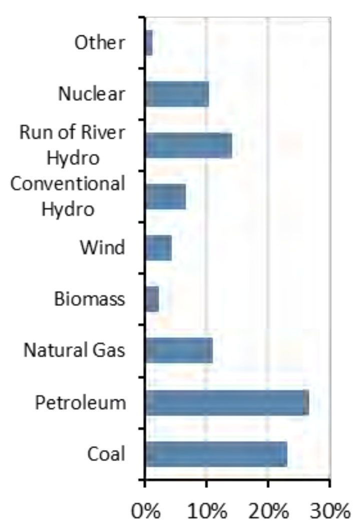
On-Peak Reserve Margin



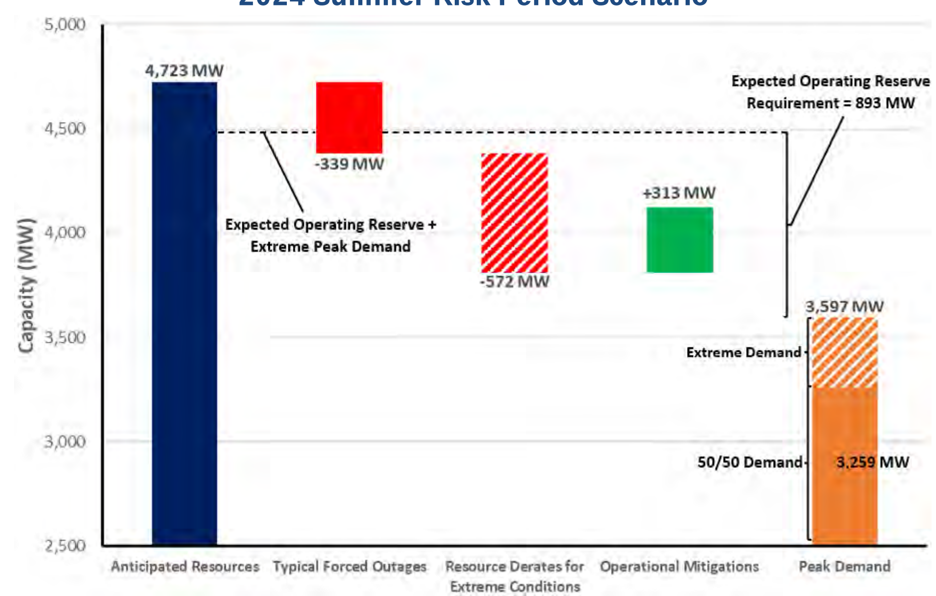
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., DR and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2024 Summer 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 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies

NPCC-New England

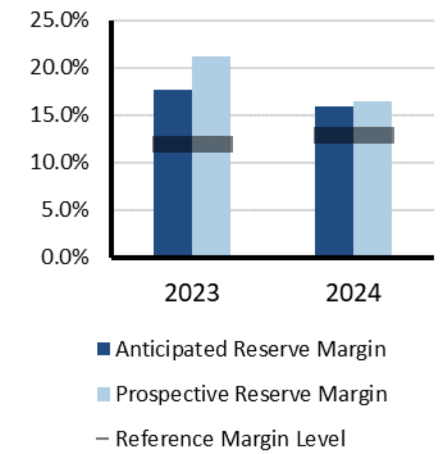
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

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

Highlights

- The New England area expects to have sufficient resources to meet the 2024 summer peak demand forecast.
- 330 MW of resources are currently on emergency outage but are scheduled to be available during the summer operating period.
- The 50/50 peak summer demand is forecast to be 24,633 MW for the weeks beginning June 2, 2024, through September 15, 2024, with a lowest projected net margin of -401 MW (-1.6%). This margin assumes a net interchange of 1,297 MW, which is capacity backed. However, ISO-NE typically imports around 3,000 MW during summer peak load conditions. For this *SRA*, the established Reference Margin Level is 12.9%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation.
- The 2024 summer demand forecast factors in demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.

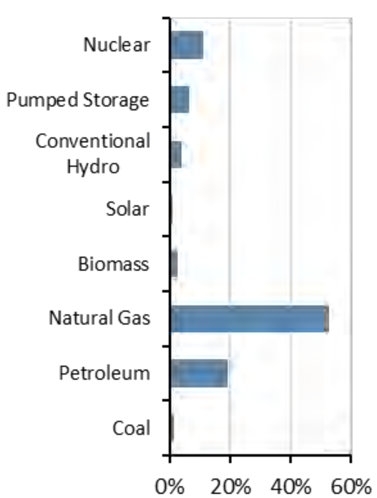
On-Peak Reserve Margin



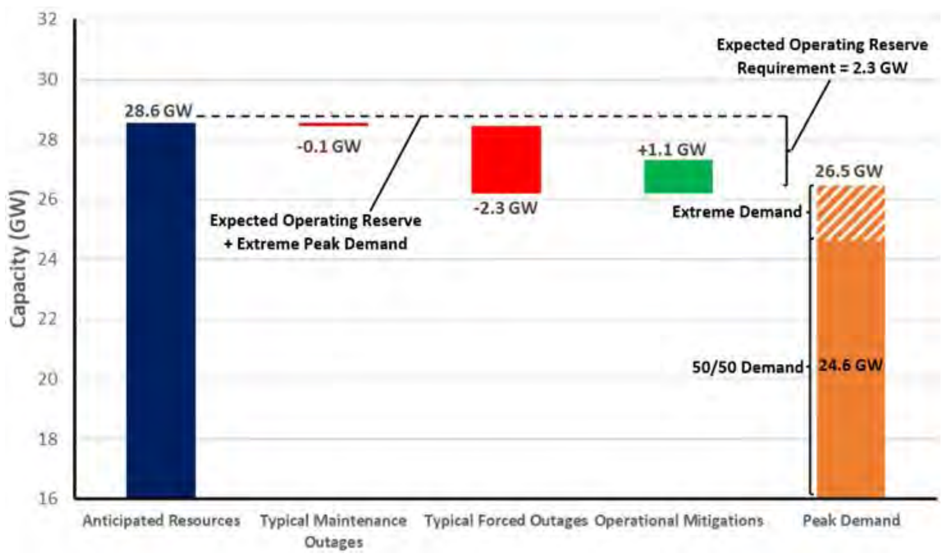
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Operating mitigations (e.g., DR and transfers) are likely to be needed to meet peak demand. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

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

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

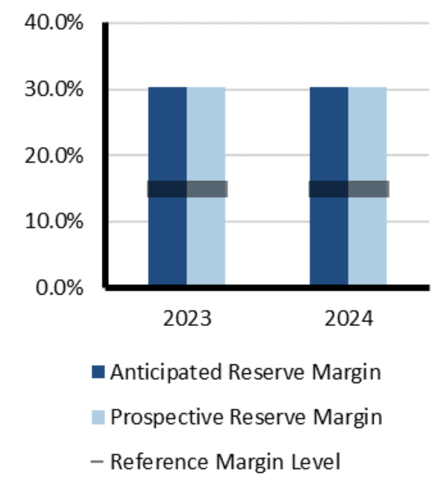
NPCC-New York

NPCC-New York is an assessment area consisting of the NYISO service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established RML is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2024–2025 IRM at 22.0%.

Highlights

- NYISO is not anticipating any operational issues in the New York Control Area for the upcoming summer.
- No unanticipated operating conditions occurred during the summer 2023 season.
- Adequate capacity margins are anticipated, and existing operating procedures are sufficient to handle any issues that may occur.

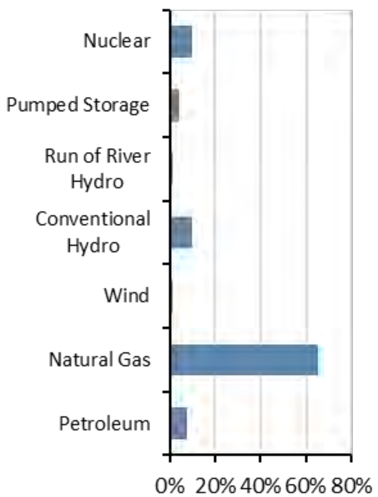
On-Peak Reserve Margin



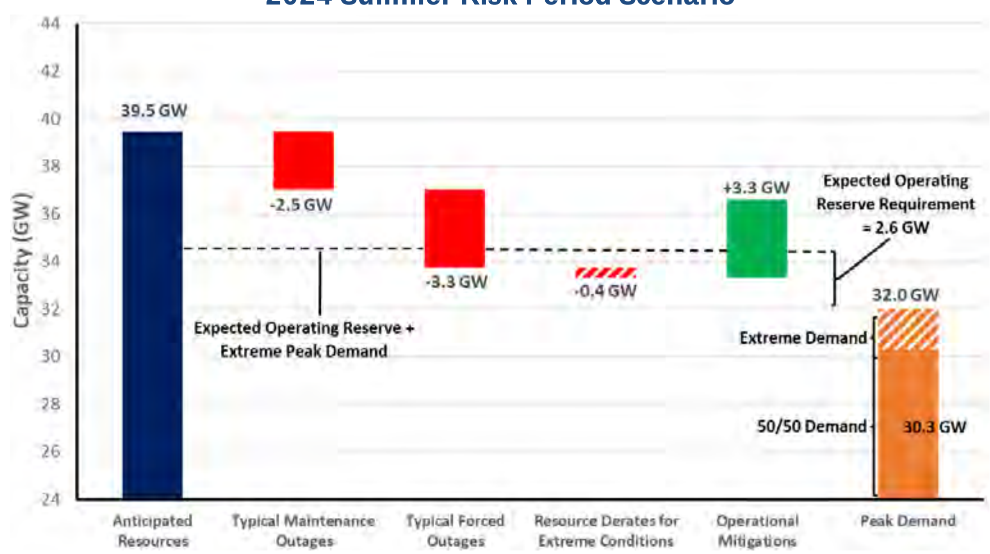
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., DR and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Fuel Mix



2024 Summer 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) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area emergency operations manual

NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The IESO is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

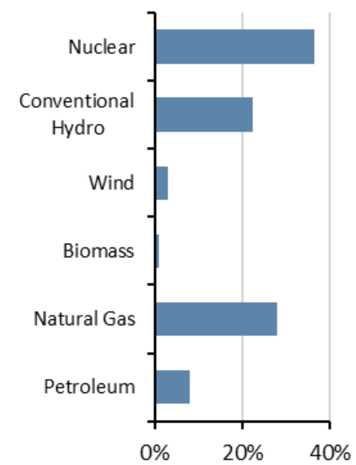
- Overall, Ontario is operating within a period in which generation and transmission outages are more challenging to accommodate. The IESO has been actively coordinating and planning with market participants to maintain reliability.
- The Ontario grid is better positioned for Summer 2024 than it was for Summer 2023.
- This season, the grid will benefit from fewer coincident planned generator outages, progress being made on nuclear refurbishments, increased capacity secured through the capacity auction, and new demand-side management programs, including the Interruptible Rate Pilot and Peak Perks.
- The system will be adequate in Summer 2024 under normal weather conditions. It is also expected to be adequate during extreme weather conditions with the availability of up to 2,000 MW of imports from neighboring jurisdictions or other operating actions to ensure reliability.

On-Peak Reserve Margin

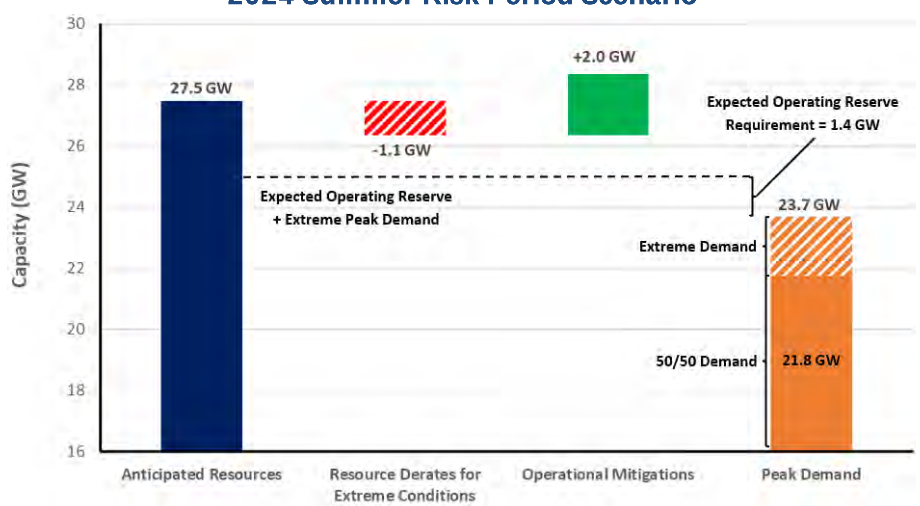
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer 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 based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies

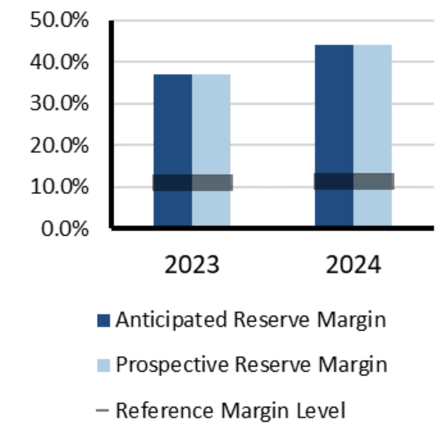
NPCC-Québec

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 high-voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- The Québec area forecasted summer peak demand (excluding April, May, and September) is 22,922 MW during the week beginning August 11, 2024, with a forecasted net margin of 7,423 MW (32.4%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas, if needed, up to the transfer capability available.

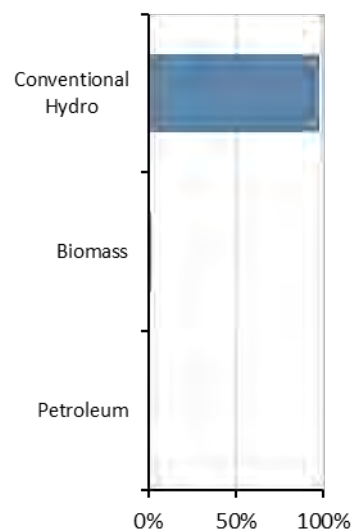
On-Peak Reserve Margin



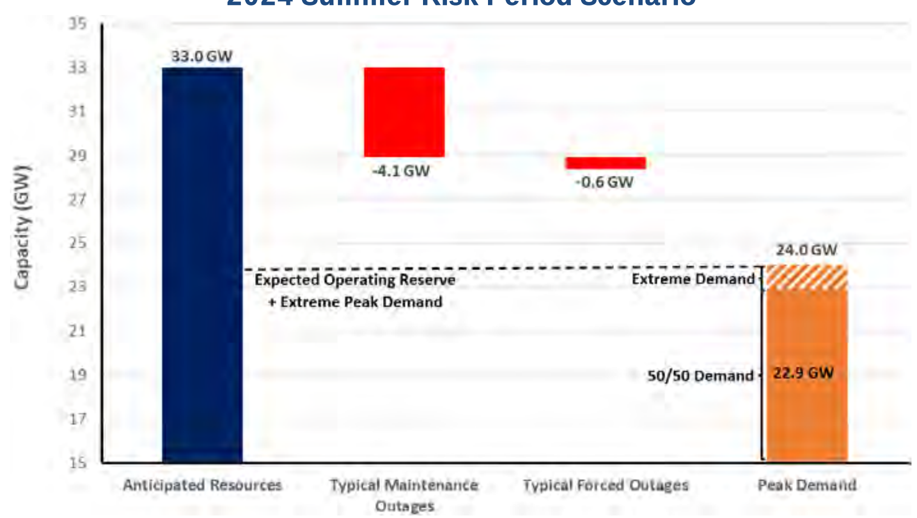
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Net Firm Transfers: Anticipated exports to neighbors during the risk hour

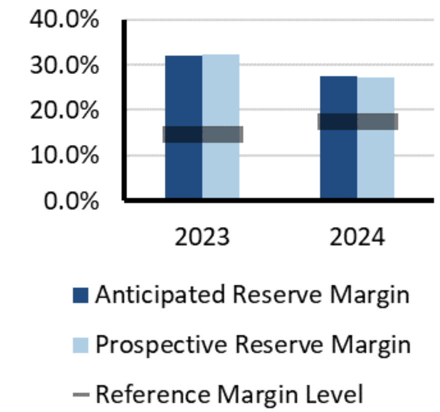
PJM

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

Highlights

- PJM expects no resource problems over the 2024 summer peak season. PJM is forecasting around 29% installed reserves (including expected committed DR), which is well above the target IRM of 17.7%. The increase of 1.8 percentage points of the reserve requirement is driven by adjusted load forecast parameters.
- Rising demand, generator retirements, and slower-than-anticipated resource additions contribute to lower reserve margins compared to last summer.
- The greatest load-loss risk remains the hour with highest forecasted demand due to the low penetration of variable energy resources relative to PJM's peak load.

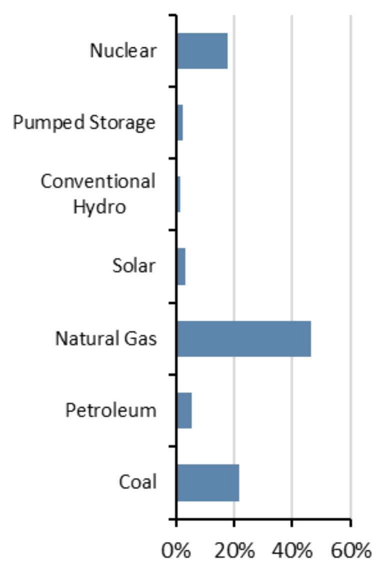
On-Peak Reserve Margin



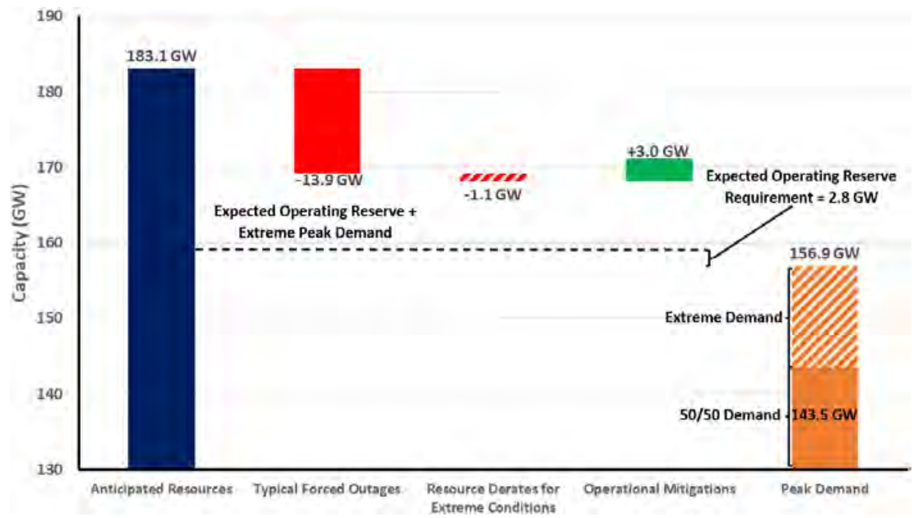
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Based on historical data and trending

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

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

SERC-Central

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

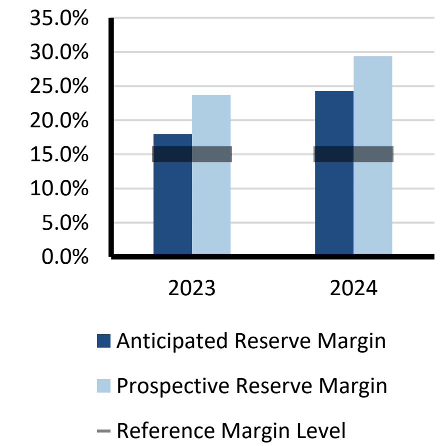
Highlights

- SERC-Central will have higher reserves compared to last summer due to increased firm imports and additions of gas and solar generation.
- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- There is a moderate risk of transmission impacts due to severe weather. The advanced age and material condition of older coal- and gas-fired generators could result in potential reliability challenges. Entities are mitigating these risks through summer readiness processes, pursuing short-term market opportunities, and leveraging demand-side management programs as necessary.

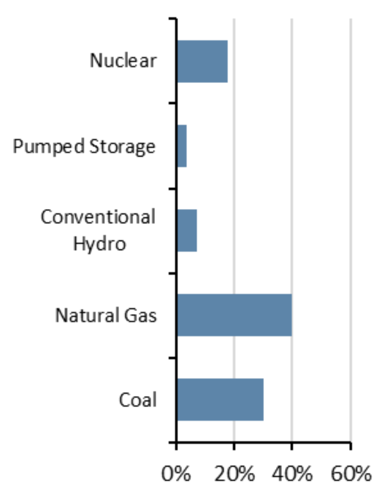
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

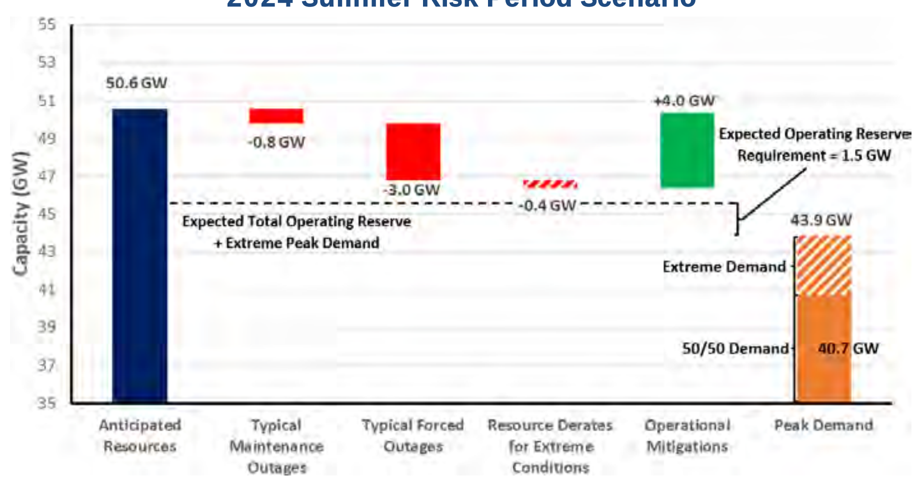
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 1.9 GW based on operational/emergency procedures

SERC-East

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

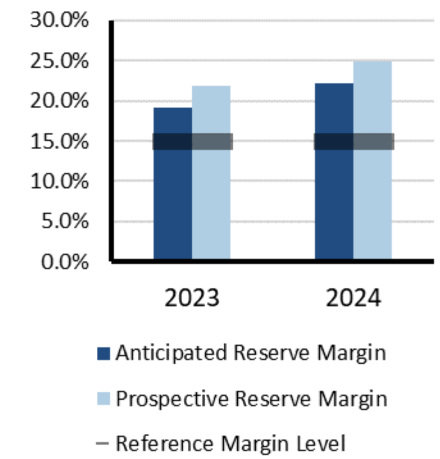
Highlights

- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics show some risk for energy resource adequacy during the summer months of July and August in the afternoon hours.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

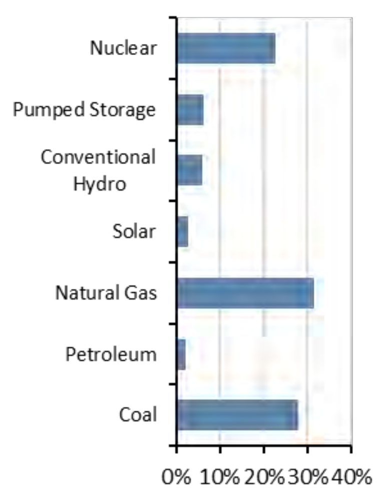
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

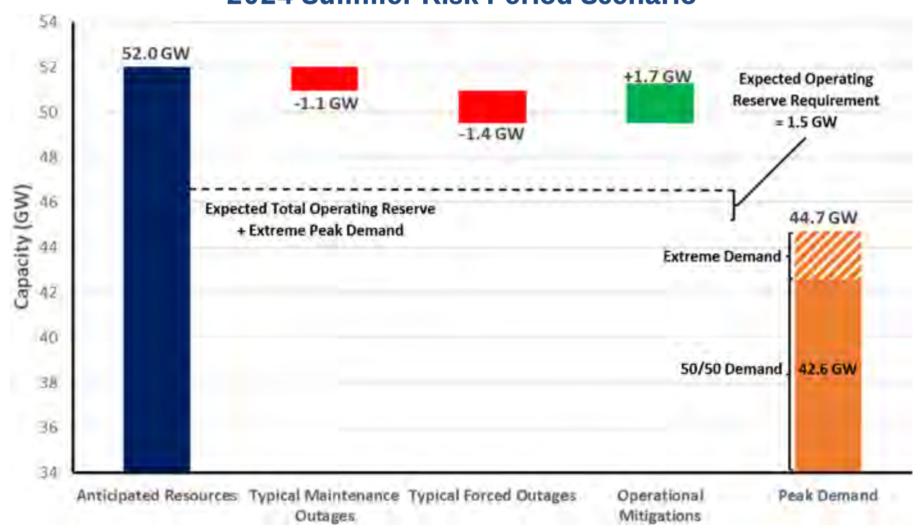
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.5 GW based on operational/emergency procedures

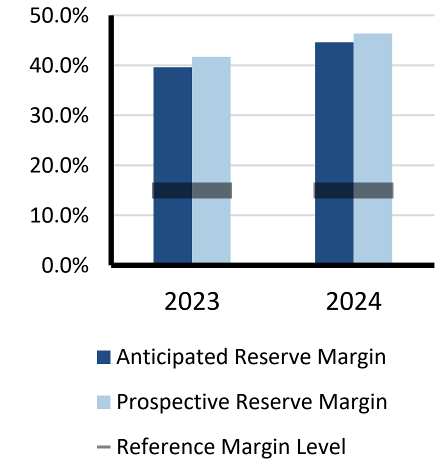
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- Expected resources meet operating reserve requirements under the assessed scenarios.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

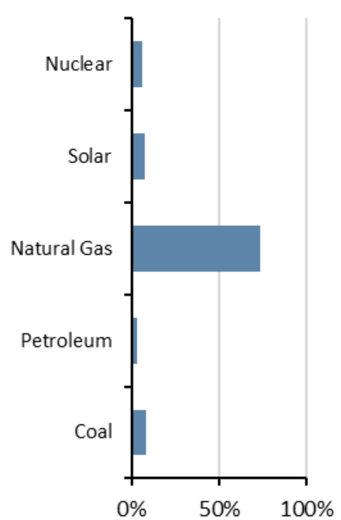
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario

Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

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

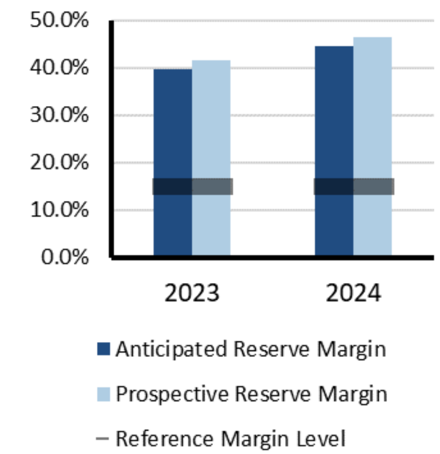
SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- Expected resources meet operating reserve requirements under the assessed scenarios.
- A new 1,100 MW nuclear unit and additional solar generation will give SERC-Southeast higher reserves compared to last summer.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- With the increased penetration of variable energy resources (VER), the curtailment of VER during light-load conditions to support operations may become more prevalent. This, in combination with the retirement of resources, increases the operational challenges in managing the ramps in some areas of SERC-Southeast.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system. They actively participate in the SERC Near-Term, Long-Term, and Resource Adequacy Working Groups, which identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.

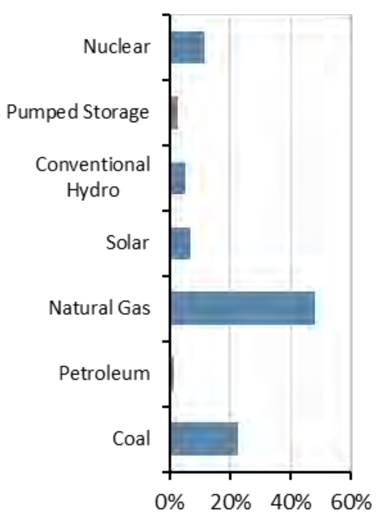
On-Peak Reserve Margin



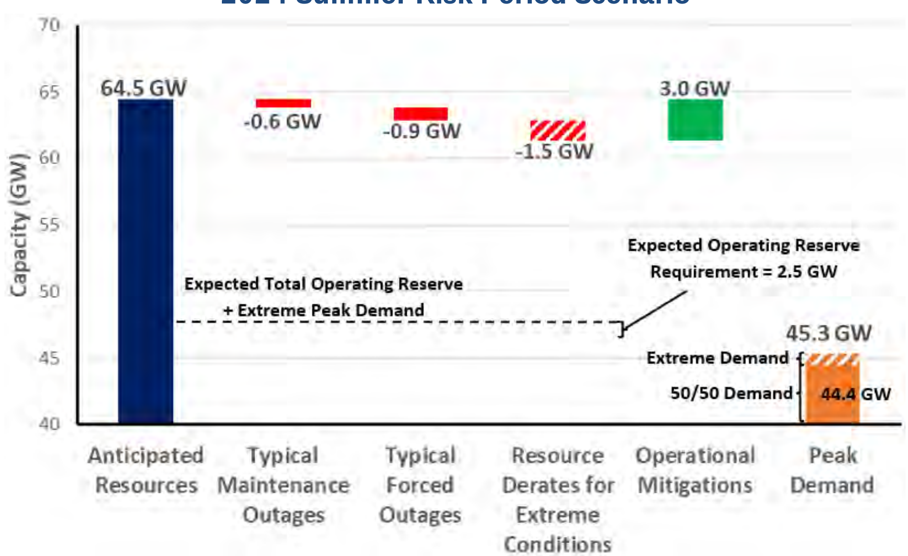
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

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

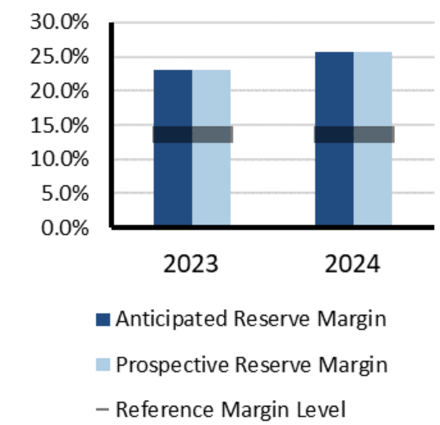
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

- Given an ARM of 25.6% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for the August peak load hour given expected normal summer system conditions.
- Solar and battery energy storage installed capacity has grown by about 4,500 and 1,600 MW, respectively, since last August.
- Continued robust growth in both loads and intermittent renewable resources has elevated the risk of emergency conditions in the evening hours when solar generation begins to ramp down.
- ERCOT's probabilistic risk assessment indicates an elevated risk of having to declare EEAs during hours ending 8:00–9:00 p.m. Central on the August peak load day. ERCOT judges an hour to have elevated risk (as opposed to low risk) when the probability of an EEA is greater than 10%. The EEA probability for these two hours is about 16% and 18%, respectively.
- Contributing to the elevated risk is a potential need, under certain grid conditions, to limit power transfers from South Texas into the San Antonio region. Conditions could cause overloads on the lines that make up the South Texas export and import interfaces, necessitating South Texas generation curtailments and potential firm load shedding to avoid cascading outages. The risk is greatest when ERCOT has extremely high net loads in the early evening hours. This issue will be addressed with mitigation measures including the construction of the San Antonio South Reliability Project, which is anticipated to be completed by Summer 2027.

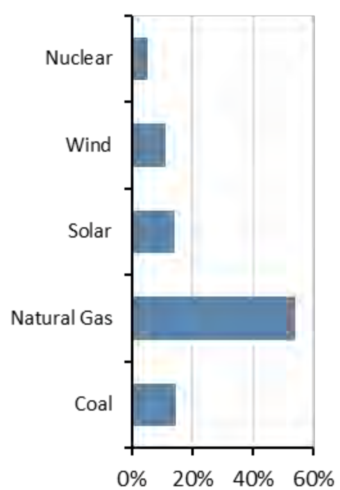
On-Peak Reserve Margin



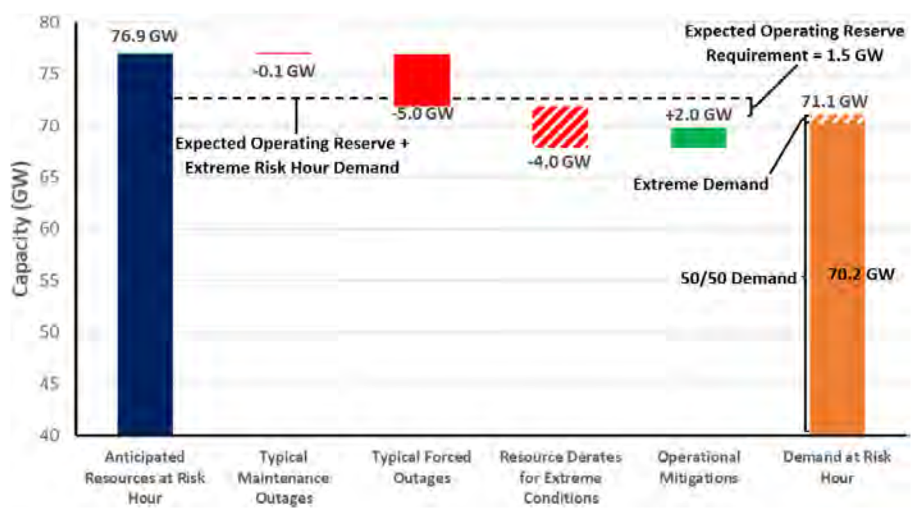
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is risk of supply shortages as solar generation ramps down during the early evening hours when system load is high and transmission constraints limit transfers.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports

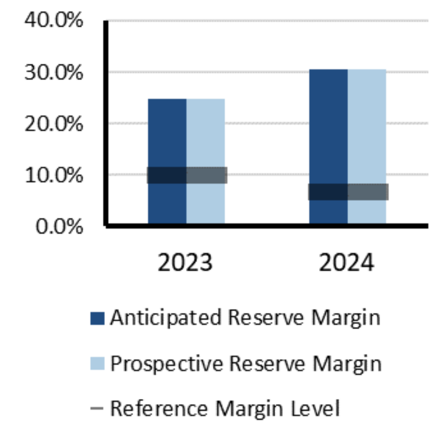
WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

Highlights

- Thermal and renewable capacity are being added to the area to address rapid load growth, but supply chain issues causing project delays or cancellations may be an issue.
- Thermal tier 1 resources for this upcoming summer include a new 900 MW natural gas combined-cycle facility and the conversion of two existing coal units to two 1x1 natural gas combustion turbine sites with 932 MW (112 incremental MW) of capacity after the steam turbine tie in. The two coal sites undergoing conversion to natural gas are the only remaining coal facilities operating in the area.
- Issues maintaining rate of change of frequency (ROCOF) during islanded or near-islanded situations with high IBR output and low demand is also a concern.
- Alberta is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- Alberta shows no LOLH or EUE for the upcoming summer season.

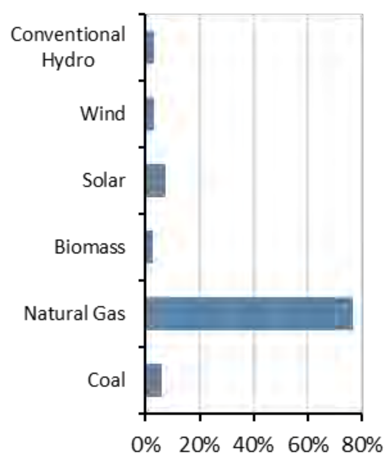
On-Peak Reserve Margin



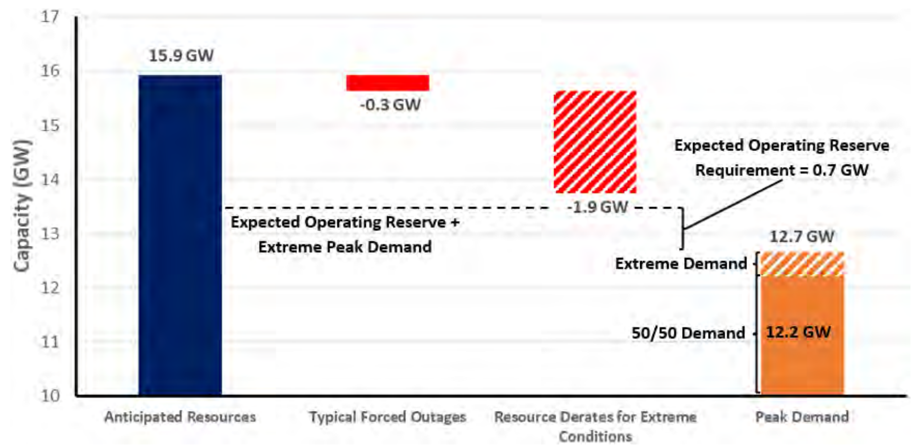
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

WECC-BC

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

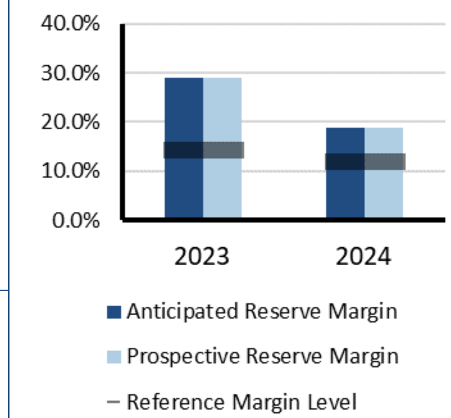
Highlights

- British Columbia faces operational challenges on multiple fronts, including drought, wildfires, and rapid electrification in the residential, commercial, industrial, and transportation sectors.
- British Columbia is expected to have sufficient resource availability to meet reserves at the peak demand hour (5:00–6:00 p.m.) under most conditions. However, above-normal demand that coincides with low hydro output could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates including low hydro output.
- WECC's probabilistic analysis shows no LOLH or EUE for British Columbia during the upcoming summer season.

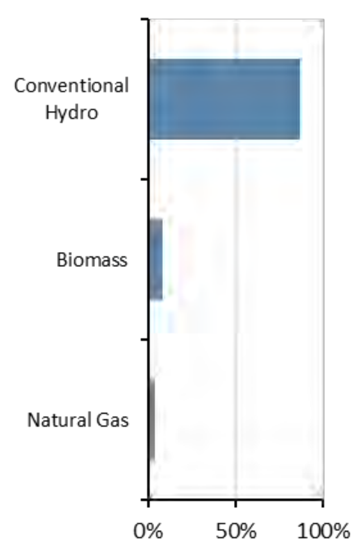
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

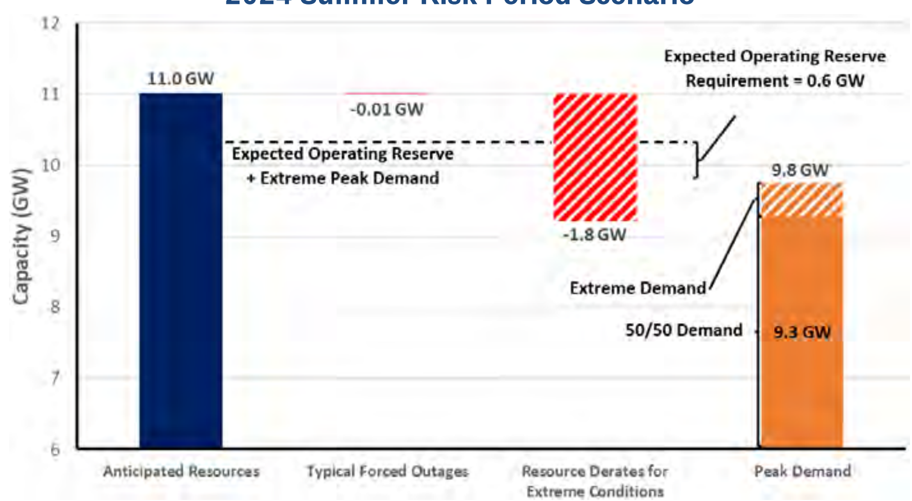
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

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

WECC-CA / MX

WECC-CA/MX is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

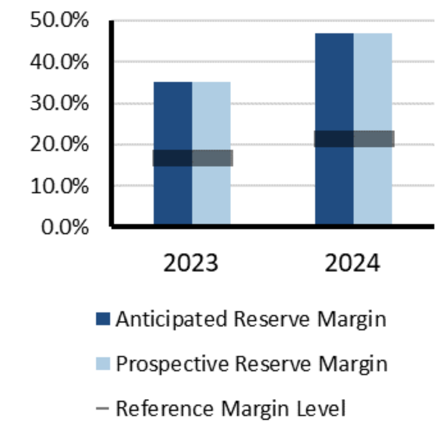
Highlights

- Drought conditions, which were a concern prior to 2023, have been alleviated for the upcoming summer.
- CA/MX is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). The riskiest hour for CA/MX is the hour ending 6:00–7:00 p.m. when solar output is low, causing the area to rely on imports to meet demand.
- In WECC's probabilistic analysis, CA/MX is projected to have LOLH ranging from negligible to 0.8 hours with the greatest risk of EUE and LOLH being in the Baja (Mexico) part of CA/MX. Variation in LOLH in the analysis is attributable to the amount of Tier 1 resource additions that connect before the later months. Supply chain issues resulting in the delay or cancellation of Tier 1 projects are a potential risk this summer for CA/MX.
- WECC's analysis considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.

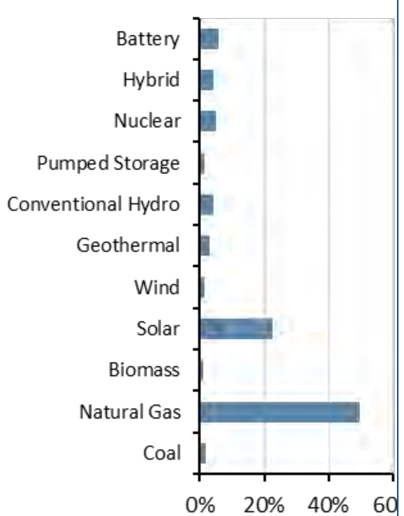
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could necessitate operating mitigations (e.g., DR and transfers) and EEAs.

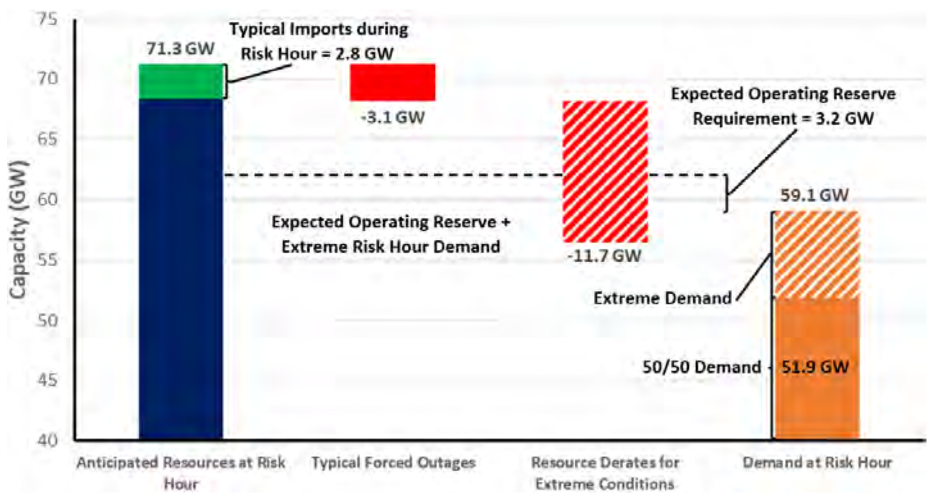
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario (7 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 7:00 p.m. local time as solar PV output is diminished and demand remains high

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

Forced Outages: Estimated using market forced outage model

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

WECC-NW

WECC-NW is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and 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 include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada and the northern portion of Baja California in Mexico as well as all or portions of the 14 western U.S. states in between.

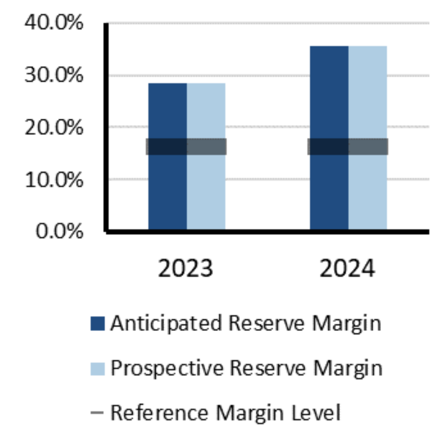
Highlights

- Operational challenges for the Northwest include supply chain issues potentially resulting in project delays or cancellations and unprecedented flow patterns associated with the expansion of IBRs.
- The Northwest is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.). This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- The Northwest shows no LOLH or EUE for the upcoming summer season.

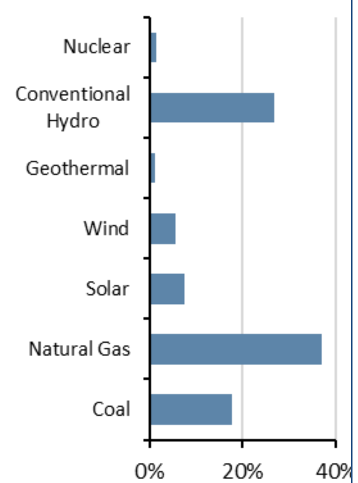
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

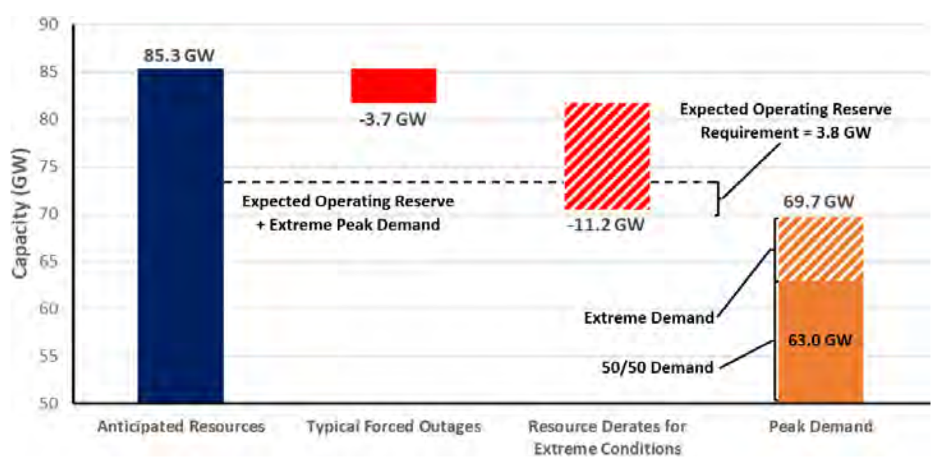
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

WECC-SW

WECC-SW is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and parts of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. 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 U.S. states in between.

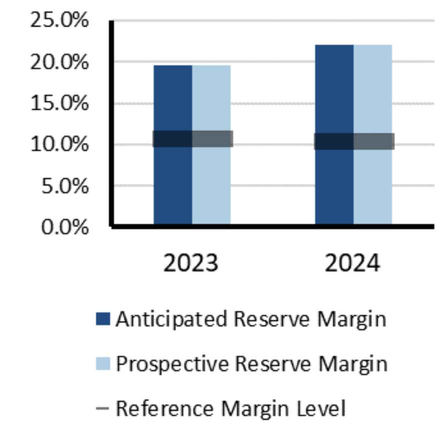
Highlights

- Operational challenges for the Southwest include drought, wildfires, derates of gas facilities due to extreme heat, and supply chain issues potentially affecting thermal resource return to service dates and CODs.
- The Southwest is expected to have sufficient resource availability to meet reserves at the peak demand hour (4:00–5:00 p.m.) under most conditions. However, above-normal demand that coincides with high generator forced outages or other low-resource conditions could result in a reserve shortage. This evaluation considers a 1-in-10 probability (90th percentile) level for peak demand and a combination of resource derates.
- The Southwest shows no LOLH or EUE for the upcoming summer season in WECC's probabilistic analysis.

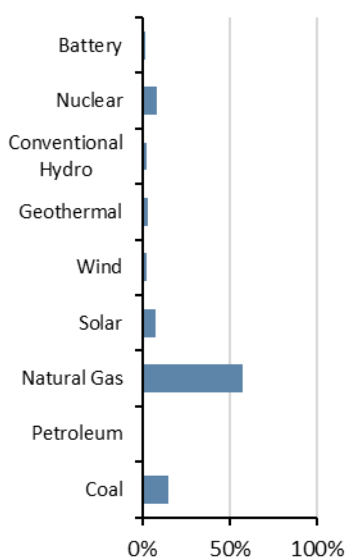
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (e.g., DR and transfers) and EEAs.

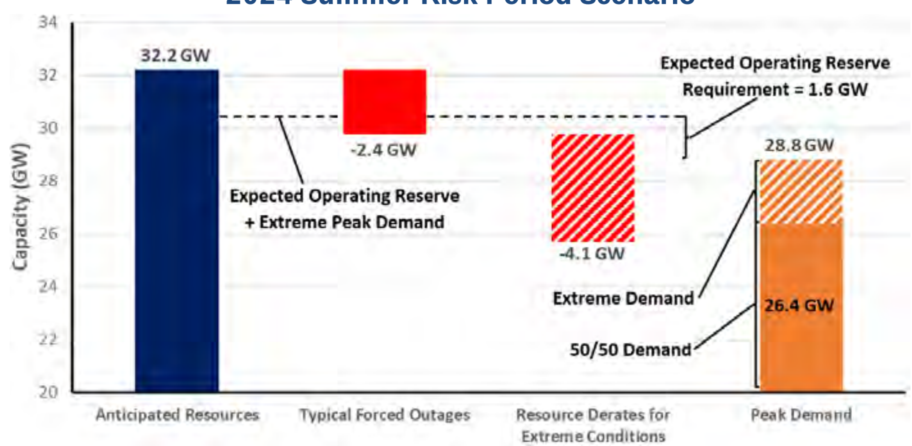
On-Peak Reserve Margin



On-Peak Fuel Mix



2024 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour 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 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.
• *2023 Long-Term Reliability Assessment* data has been used for most of this 2024 summer 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[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] 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 DR 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 PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.   • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.   • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

[12] *Glossary of Terms* used in NERC Reliability Standards
[13] The summer season represents June–September and the winter season represents December–February.
[14] 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.
[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for 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, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] 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 ARMs to meet or exceed their RML for the 2024 summer as shown in **Figure 4**.

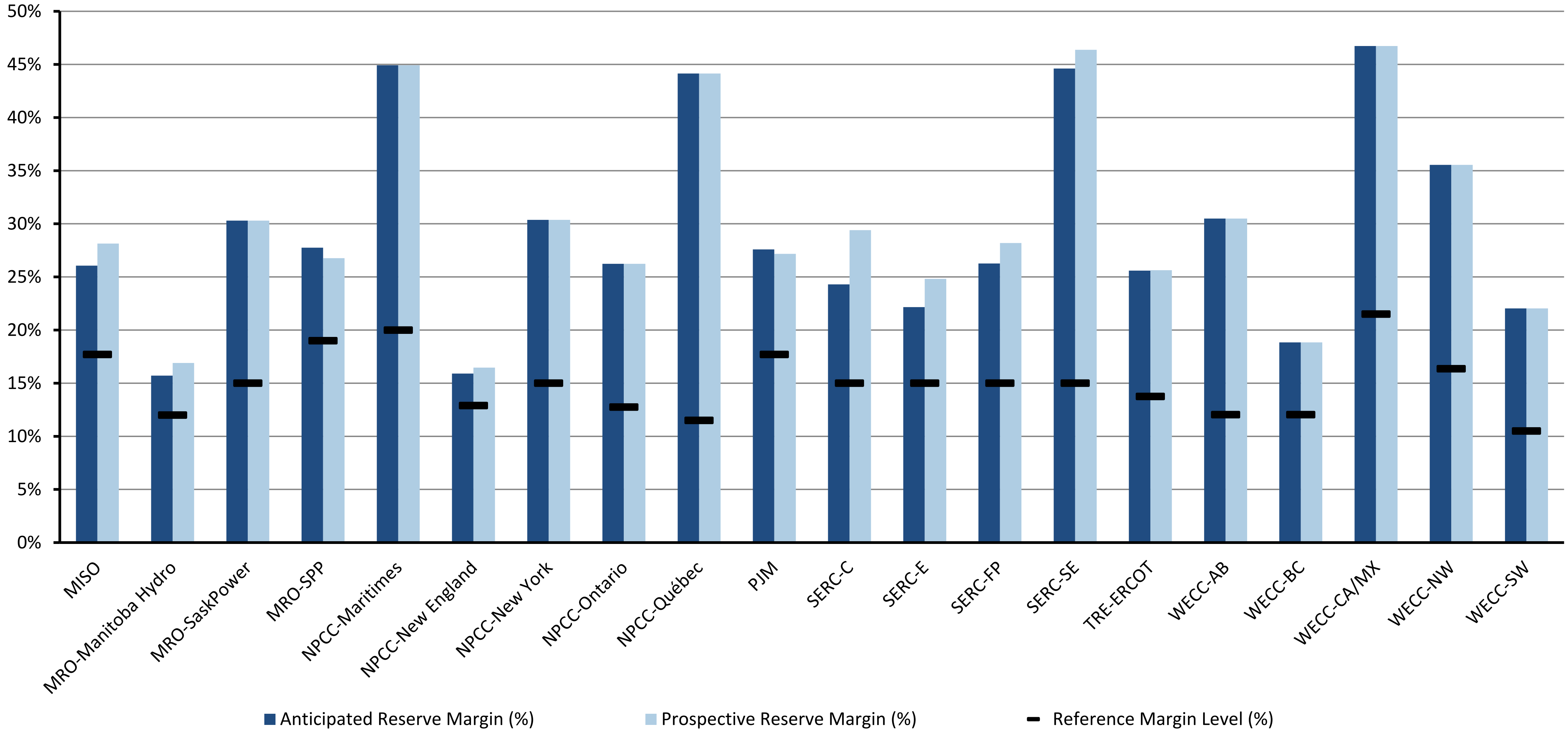


Figure 4: Summer 2024 Anticipated / Prospective Reserve Margins Compared to Reference Margin Level

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

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2023 summer to the 2024 summer. A significant decline can signal potential operational issues for the upcoming season. Both MRO-Manitoba Hydro and WECC-BC have noticeable reductions in their ARM levels for the 2024 summer. MRO-Manitoba Hydro does not anticipate elevated risk for the upcoming summer, but WECC-BC is experiencing increasing forecasted demand and drought conditions, increasing risk heading into the 2024 summer. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.

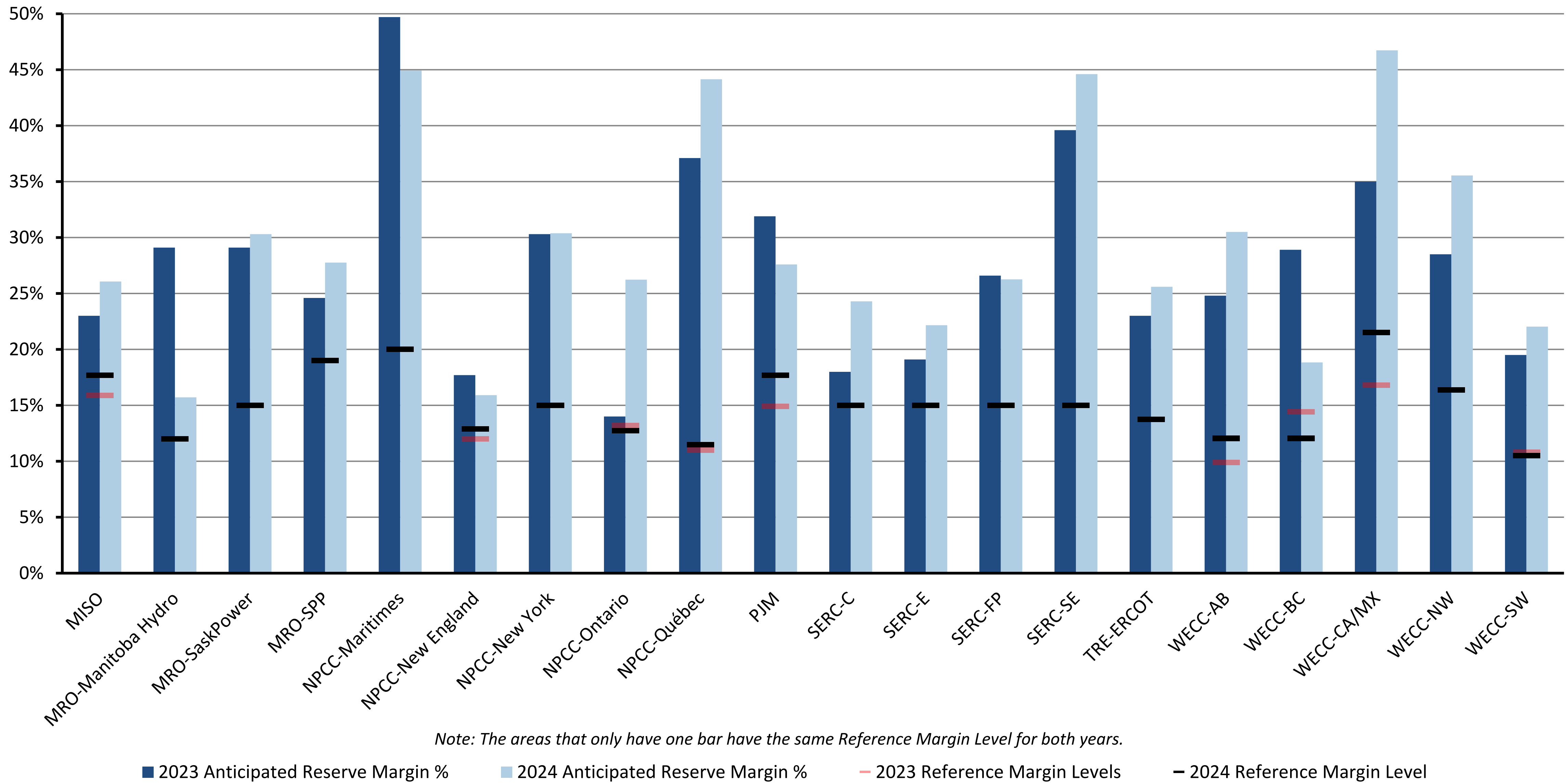


Figure 5: Summer 2023 and Summer 2024 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

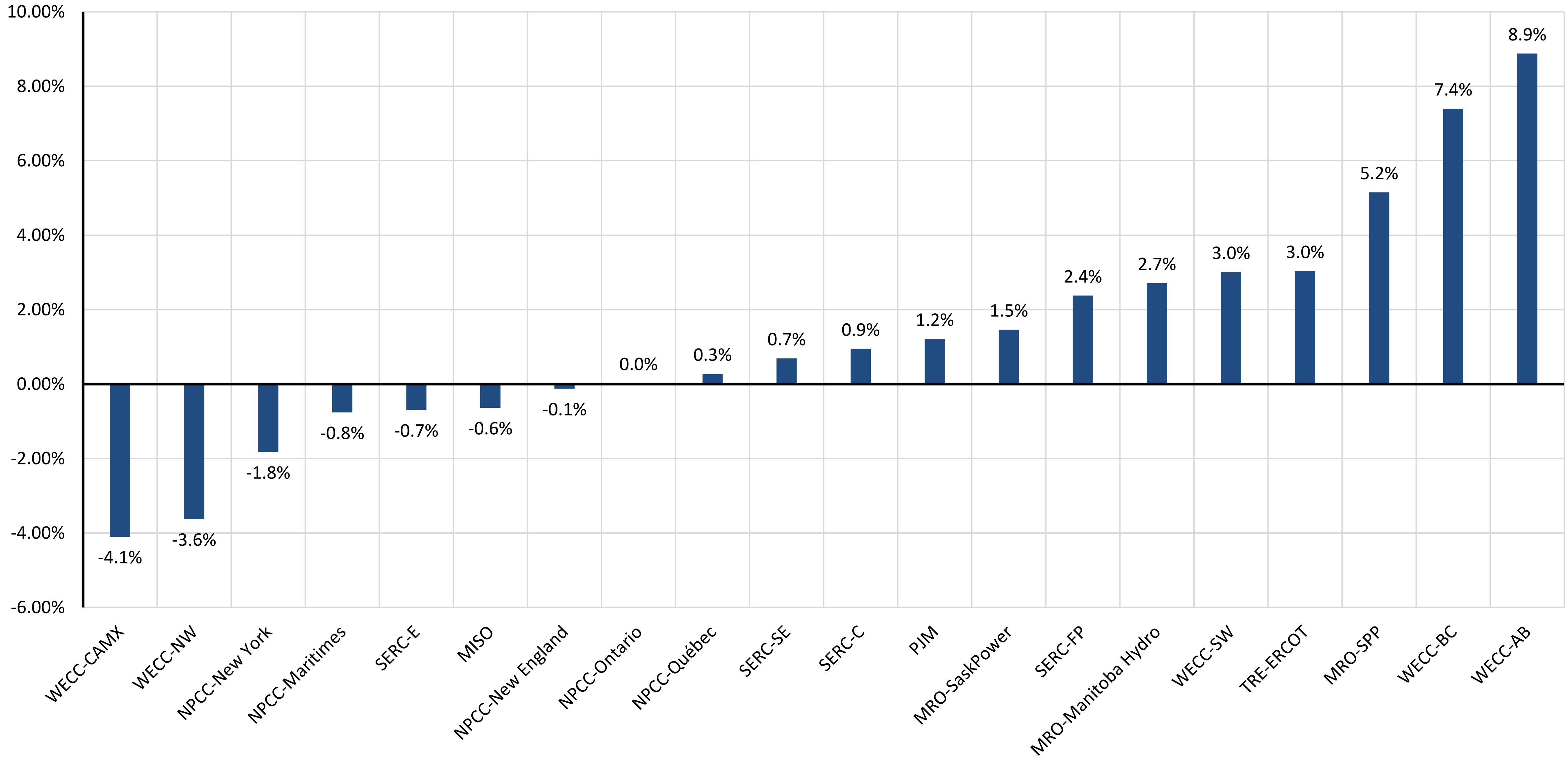


Figure 6: Changes in Net Internal Demand—Summer 2023 Forecast Compared to Summer 2024 Forecast

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

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	123,728	124,830	0.9%
Demand Response: Available	6,903	8,750	26.8%
Net Internal Demand	116,825	116,079	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	140,650	143,866	2.3%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	3,018	2,471	-18.1%
Anticipated Resources	143,668	146,337	1.9%
Existing-Other Capacity	668	1,833	174.4%
Prospective Resources	151,579	148,740	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.0%	26.1%	3.1
Prospective Reserve Margin	29.7%	28.1%	-1.6
Reference Margin Level	15.9%	17.7%	1.8

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,060	3,143	2.7%
Demand Response: Available	0	0	-
Net Internal Demand	3,060	3,143	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,731	5,615	-2.0%
Tier 1 Planned Capacity	91	0	-100.0%
Net Firm Capacity Transfers	-1,872	-1,978	5.7%
Anticipated Resources	3,950	3,637	-7.9%
Existing-Other Capacity	34	37	9.7%
Prospective Resources	3,984	3,674	-7.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	15.7%	-13.4
Prospective Reserve Margin	30.2%	16.9%	-13.3
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,539	3,590	1.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,489	3,540	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,213	4,323	2.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,503	4,613	2.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,503	4,613	2.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	30.3%	1.2
Prospective Reserve Margin	29.1%	30.3%	1.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,468	56,316	5.3%
Demand Response: Available	842	979	16.3%
Net Internal Demand	52,626	55,337	5.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	65,821	70,855	7.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-238	-157	-33.9%
Anticipated Resources	65,583	70,698	7.8%
Existing-Other Capacity	0	0	-
Prospective Resources	65,036	70,151	7.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.6%	27.8%	3.2
Prospective Reserve Margin	23.6%	26.8%	3.2
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,612	3,586	-0.7%
Demand Response: Available	328	327	-0.3%
Net Internal Demand	3,284	3,259	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,834	4,660	-3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	81	63	-22.2%
Anticipated Resources	4,915	4,723	-3.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,915	4,723	-3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	49.7%	44.9%	-4.8
Prospective Reserve Margin	49.7%	44.9%	-4.8
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	32,049	31,541	-1.6%
Demand Response: Available	1,226	1,281	4.5%
Net Internal Demand	30,823	30,260	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,216	37,867	1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,932	1,585	-45.9%
Anticipated Resources	40,148	39,452	-1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	40,148	39,452	-1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	30.4%	0.1
Prospective Reserve Margin	30.3%	30.4%	0.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,111	25,294	0.7%
Demand Response: Available	447	661	47.9%
Net Internal Demand	24,664	24,633	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,997	27,255	-2.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,030	1,297	25.9%
Anticipated Resources	29,027	28,552	-1.6%
Existing-Other Capacity	872	138	-84.2%
Prospective Resources	29,899	28,690	-4.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.7%	15.9%	-1.8
Prospective Reserve Margin	21.2%	16.5%	-4.7
Reference Margin Level	12.0%	12.9%	0.9

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,439	22,753	1.4%
Demand Response: Available	687	996	45.0%
Net Internal Demand	21,752	21,757	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	24,575	26,856	9.3%
Tier 1 Planned Capacity	9	9	-1.6%
Net Firm Capacity Transfers	223	600	169.1%
Anticipated Resources	24,807	27,465	10.7%
Existing-Other Capacity	0	0	-
Prospective Resources	24,807	27,465	10.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.0%	26.2%	12.2
Prospective Reserve Margin	14.0%	26.2%	12.2
Reference Margin Level	13.2%	12.8%	-0.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,859	22,922	0.3%
Demand Response: Available	0	0	-
Net Internal Demand	22,859	22,922	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,690	35,731	6.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,353	-2,689	14.3%
Anticipated Resources	31,337	33,042	5.4%
Existing-Other Capacity	0	0	-
Prospective Resources	31,337	33,042	5.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.1%	44.1%	7.0
Prospective Reserve Margin	37.1%	44.1%	7.0
Reference Margin Level	11.0%	11.5%	0.5

SERC-Central			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,223	42,636	1.0%
Demand Response: Available	1,910	1,941	1.6%
Net Internal Demand	40,313	40,695	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	46,964	48,677	3.6%
Tier 1 Planned Capacity	93	332	257.3%
Net Firm Capacity Transfers	1,068	2,592	142.7%
Anticipated Resources	47,556	51,601	8.5%
Existing-Other Capacity	2,313	2,074	-10.3%
Prospective Resources	49,868	51,083	2.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.0%	26.8%	8.8
Prospective Reserve Margin	23.7%	25.5%	1.8
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	149,059	151,247	1.5%
Demand Response: Available	7,288	7,756	6.4%
Net Internal Demand	141,771	143,491	1.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	186,540	183,690	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	463	-607	-231.1%
Anticipated Resources	187,003	183,083	-2.1%
Existing-Other Capacity	0	0	-
Prospective Resources	187,466	182,476	-2.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.9%	27.6%	-4.3
Prospective Reserve Margin	32.2%	27.2%	-5.0
Reference Margin Level	14.9%	17.7%	2.8

SERC-East			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,889	43,567	-0.7%
Demand Response: Available	1,008	985	-2.3%
Net Internal Demand	42,881	42,582	-0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	50,452	51,304	1.7%
Tier 1 Planned Capacity	0	122	-
Net Firm Capacity Transfers	624	593	-5.0%
Anticipated Resources	51,076	52,019	1.8%
Existing-Other Capacity	1,182	1,131	-4.3%
Prospective Resources	52,258	52,557	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.1%	22.2%	3.1
Prospective Reserve Margin	21.9%	23.4%	1.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,195	53,293	2.1%
Demand Response: Available	2,898	2,824	-2.6%
Net Internal Demand	49,297	50,469	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	60,074	60,962	1.5%
Tier 1 Planned Capacity	1,742	34	-98.0%
Net Firm Capacity Transfers	589	200	-66.0%
Anticipated Resources	62,405	61,196	-1.9%
Existing-Other Capacity	776	985	27.0%
Prospective Resources	63,181	61,981	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.6%	21.3%	-5.3
Prospective Reserve Margin	28.2%	22.8%	-5.4
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	82,307	84,818	3.1%
Demand Response: Available	3,380	3,496	3.4%
Net Internal Demand	78,927	81,323	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	94,580	99,541	5.2%
Tier 1 Planned Capacity	2,445	2,578	5.4%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	97,045	102,139	5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	97,073	102,167	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.0%	25.6%	2.6
Prospective Reserve Margin	23.0%	25.6%	2.6
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,127	46,021	-0.2%
Demand Response: Available	2,010	1,599	-20.4%
Net Internal Demand	44,117	44,422	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,559	63,918	7.3%
Tier 1 Planned Capacity	2,865	1,738	-39.4%
Net Firm Capacity Transfers	-815	-1,192	46.3%
Anticipated Resources	61,609	64,463	4.6%
Existing-Other Capacity	908	785	-13.5%
Prospective Resources	62,517	66,441	6.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	39.6%	45.1%	5.5
Prospective Reserve Margin	41.7%	49.6%	7.9
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,206	12,201	8.9%
Demand Response: Available	0	0	-
Net Internal Demand	11,206	12,201	8.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,759	13,941	1.3%
Tier 1 Planned Capacity	227	1,981	772.7%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	13,986	15,922	13.8%
Existing-Other Capacity	0	0	-
Prospective Resources	13,986	15,922	13.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.8%	30.5%	5.7
Prospective Reserve Margin	24.8%	30.5%	5.7
Reference Margin Level	9.9%	6.7%	-3.2

WECC-BC			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	8,636	9,275	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	8,636	9,275	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,135	11,022	-1.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,135	11,022	-1.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,135	11,022	-1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.9%	18.8%	-10.1
Prospective Reserve Margin	28.9%	18.8%	-10.1
Reference Margin Level	9.7%	12.0%	-2.4

WECC-CA / MX			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,356	54,029	-4.1%
Demand Response: Available	862	810	-6.0%
Net Internal Demand	55,494	53,219	-4.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	69,408	70,841	2.1%
Tier 1 Planned Capacity	5,522	6,906	25.1%
Net Firm Capacity Transfers	0	340	-
Anticipated Resources	74,930	78,087	4.2%
Existing-Other Capacity	0	0	-
Prospective Resources	74,930	78,087	4.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	35.0%	46.7%	11.7
Prospective Reserve Margin	35.0%	46.7%	11.7
Reference Margin Level	16.8%	21.5%	4.7

WECC-SW			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,992	26,661	2.6%
Demand Response: Available	380	278	-26.8%
Net Internal Demand	25,612	26,383	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,206	28,336	8.1%
Tier 1 Planned Capacity	1,655	2,338	41.3%
Net Firm Capacity Transfers	2,747	1,523	-44.6%
Anticipated Resources	30,608	32,197	5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	30,608	32,197	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.5%	22.0%	2.5
Prospective Reserve Margin	19.5%	22.0%	2.5
Reference Margin Level	10.8%	10.5%	-0.3

WECC-NW			
Demand, Resource, and Reserve Margins	**2023 SRA**	**2024 SRA**	**2023 vs. 2024 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	66,366	63,865	-3.8%
Demand Response: Available	1,038	907	-12.6%
Net Internal Demand	65,328	62,958	-3.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	76,587	78,057	1.9%
Tier 1 Planned Capacity	2,350	4,089	74.0%
Net Firm Capacity Transfers	5,004	3,192	-36.2%
Anticipated Resources	83,941	85,338	1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	83,941	85,338	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.5%	35.5%	7.0
Prospective Reserve Margin	28.5%	35.5%	7.0
Reference Margin Level	16.3%	16.4%	0.1

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area												
	Wind			Solar			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,931	5,599	18%	10,169	4,981	49%	1,621	1,488	92%	2,678	2,591	97%
MRO-Manitoba Hydro	259	48	19%	–	-	0%	202	92	46%	-	-	0%
MRO-SaskPower	616	208	34%	30	6	21%	848	655	77%	-	-	0%
NPCC-Maritimes	1,209	262	22%	69	-	0%	1,312	1,181	90%	13	13	100%
NPCC-New England	1,546	122	8%	3,246	1,111	34%	550	367	67%	2,077	2,038	98%
NPCC-New York	2,590	340	13%	370	53	14%	984	386	39%	20	-	0%
NPCC-Ontario	4,883	720	15%	478	66	14%	8,922	5,171	58%	-	-	0%
NPCC-Québec	3,820	-	0%	10	-	0%	446	446	100%	-	-	0%
PJM	10,495	1,703	16%	10,990	5,694	52%	2,505	2,505	100%	190	151	79%
SERC-Central	1,220	172	14%	2,074	996	48%	4,966	3,332	67%	166	70	42%
SERC-East	-	-	-	2,769	2,405	87%	3,072	3,016	98%	24	10	43%
SERC-Florida Peninsula	-	-	0%	10,023	5,643	56%	-	-	0%	538	538	100%
SERC-Southeast	-	-	0%	7,887	7,217	91%	3,303	3,259	99%	115	105	92%
SPP	34,783	5,876	17%	756	486	64%	107	54	50%	12	2	13%
Texas RE-ERCOT	39,069	9,070	23%	24,463	17,797	73%	575	450	78%	7,876	2,661	34%
WECC-AB	4,482	666	15%	1,650	786	48%	894	450	50%	190	185	97%
WECC-BC	747	140	19%	2	0	22%	16,521	9,757	59%	-	-	0%
WECC-CA/MX	7,694	1,124	15%	21,790	13,147	60%	13,725	6,265	46%	7,295	6,858	94%
WECC-NW	19,709	2,964	15%	8,853	2,595	29%	41,705	24,147	58%	779	707	91%
WECC-SW	3,329	542	16%	2,690	1,294	48%	1,201	670	56%	988	893	90%
EASTERN INTERCONNECTION	88,702	15,220	17%	48,862	28,657	59%	28,394	21,507	76%	5,832	5,517	95%
QUÉBEC INTERCONNECTION	3,820	-	0%	10	-	0%	446	446	100%	-	-	0%
TEXAS INTERCONNECTION	39,069	9,070	23%	24,463	17,797	73%	575	450	78%	7,876	2,661	34%
WECC INTERCONNECTION	35,961	5,436	15%	34,985	17,822	51%	74,046	41,289	56%	9,252	8,643	93%
All INTERCONNECTIONS	**167,552**	**29,725**	**18%**	**108,320**	**64,277**	**59%**	**103,461**	**63,692**	**62%**	**22,960**	**16,821**	**73%**

Review of 2023 Capacity and Energy Performance

High temperatures, wildfires, and weather conditions challenged electric grid operators in many parts of North America to maintain a reliable supply of electricity during 2023. Prior to summer, NERC warned that much of North America was at risk of having insufficient resources to meet electricity demand if extreme temperatures and weather conditions were to develop. It is noteworthy that, after a summer of soaring temperatures, extended heat waves, and new electricity demand records, few high-level EEAs were issued, and no disruptions occurred as a result of inadequate resources. Nonetheless, operators at BAs, TOPs, and RCs faced significant challenges and drew upon procedures and protocols to obtain all available resources, manage system demand, and ensure the flow of supplies over the transmission network. Additionally, load-serving entities and state and local officials in many parts of North America used mechanisms and public appeals to lower customer demand during periods of strained supplies. The following section describes actual demand and resource levels in comparison with NERC's *2023 SRA* and summarizes 2023 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

Systems in parts of Canada experienced challenging conditions early in the summer from high electricity demand and wildfires over large areas. Electricity transfers from Québec to neighboring Maritimes and New England were curtailed or disrupted during periods in May and June when wildfires affected transmission facilities. Peak electricity demand in Ontario occurred in early September at a level near the 90/10 demand forecast. Additional imports helped the area meet the extreme demand.

Manitoba Hydro and SaskPower both experienced peak electricity demand in excess of 90/10 summer forecasts. Manitoba Hydro's peak occurred at the start of summer in June. Operators had sufficient reserves and were able to export supplies during the peak period to neighboring areas.

SaskPower peak electricity demand occurred in late July. A forced outage at a large thermal generator early in the summer contributed to operating challenges over much of the summer period. At the time of peak demand, forced outages were significantly higher than typical for summer peak periods.

Eastern Interconnection–United States

In SPP, summer electricity demand peaked in August and exceeded 90/10 forecasts. At the hour of peak demand, SPP experienced near-normal levels of forced thermal generation outages. Wind resource performance at the time of peak demand exceeded seasonal peak forecasts, helping to alleviate the strain on supplies. However, during periods in June and July, operators at SPP issued resource advisories during periods of forecasted high demand and low or uncertain wind resource output.

MISO also experienced peak electricity demand during the same period in August; however, demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were below expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. An EEA (level 2) was issued in August due to high forecasted loads and wind uncertainty. MISO used operating procedures to ensure that sufficient reserves were maintained during periods of high electricity demand and high forced generator outages at times throughout the summer.

PJM experienced peak electricity demand in late July at a level between normal summer peak and the 90/10 forecast. Wind and solar resource output were below seasonal peak expectations, while low thermal generator outages were reported.

Peak electricity demand at NYISO and ISO-NE occurred in early September and fell below average summer peak forecasts.

Systems in the U.S. Southeast experienced peak demand above the 90/10 forecasts in mid to late August. Solar resource output exceeded the expected contributions for the peak demand period. Electricity imports into resource-constrained areas helped BAs maintain reserves during high demand periods.

Texas Interconnection–ERCOT

Extended heat waves led to record-setting system electricity demand in the ERCOT system throughout Summer 2023. Peak electricity demand occurred in mid-August at a level exceeding the 90/10 demand forecast. At the time of peak demand, wind and solar generation were slightly below expected levels for peak demand periods, and thermal generator outages were also slightly higher than normal for peak periods. Nonetheless, operators were able to maintain sufficient reserves. At various times throughout the summer, ERCOT issued public appeals for conservation to help manage high demand periods and evening periods when output from the solar resources is diminished. On September 6, ERCOT declared an EEA (level 2) to address a low-frequency condition on the system during a period of unusually high demand, declining solar output, and low wind output. Transmission system constraints led to the curtailment of some supply from wind resources in southern parts of the system. No load was shed during the event.

Western Interconnection–Canada

At the start of summer, the province of Alberta was in a state of emergency as a result of active wildfires and the threat of spreading from hot and dry conditions. A period of high demand from heat and humidity that coincided with generator forced outages and low wind conditions triggered an EEA. Alberta's system peak demand occurred in late July at a level above normal summer peak demand forecasts but below the 90/10 level. Wind and solar resource outputs were above seasonal forecast levels for peak demand periods. High temperatures in late August led to high demand at a time of planned transmission system maintenance. An EEA (level 3) was triggered when low wind conditions and insufficient imports resulted in reserve shortage.

The BC Hydro system also experienced peak electricity demand in early August at a level near the 90/10 summer peak forecast.

Western Interconnection–United States

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in mid-August at a level between the average summer peak demand forecast and the 90/10 peak demand forecast. Public appeals to shift electricity use to off-peak hours were used during some high-demand periods. The Mexico portion of the assessment area faced reserve shortages during periods in July and August as a result of high demand, generator outages, and unavailability of imports.

System peak electricity demand in the U.S. Northwest also occurred in mid-August and was below normal summer peak demand forecasts.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded normal summer peak demand forecasts. Wind and solar output fell below expected levels during the peak demand period.

2023 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	120.8	116.8 123.9	8,598	5,488	2,096	3,750	6,638
MRO-Manitoba Hydro	3.5	3.1 3.4	83	47	-		95
MRO-SaskPower	3.7	3.5 3.6	381	203	15		737
MRO-SPP	56.0	52.6 55.1	8,278	4,500	130	378	6,533
NPCC-Maritimes	3.5	3.3 3.6	131	255	40	-	1,690*
NPCC-New England	23.5	24.7 26.5	186	186	145	1,163	1,969
NPCC-New York	30.2	30.8 32.7	223	331	-	84	9,716
NPCC-Ontario	23.7	21.8 23.7	786	771	200	126	3,419*
NPCC-Québec	22.5	22.9 22.9	496	-	8		12,287*
PJM	147.6	141.8 162.7	1,278	1,688	1,826	2,984	8,020
SERC-C	44.0	40.3 43.0	15	564	673	511	1,225
SERC-E	43.3	42.9 45.6	-	-	3,032	1,473	2,129
SERC-FP	54.1	49.3 52.4	-	-	4,590	4,534	1,610
SERC-SE	45.6	44.8	-	-	2,781	4,647	2,334
TRE-ERCOT	85.4	78.9 82.3	9,557	10,293	10,431	12,509	6,699
WECC-AB	11.5	11.2 11.6	906	309	894	763	-
WECC-BC	9.2	8.6 9.2	373	137	0	1	-

2023 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
WECC-CA/MX	52.3	49.5 58.1	1,074	1,111	6,930	14,489	2,444
WECC-NW	64.7	61.0 67.2	2,137	593	3,821	1,411	4,855
WECC-SW	27.3	25.6 28.0	835	3,968	1,731	5,062	2,507
Highlighting Notes:	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.

[2] See NERC *2023 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2023 SRA*.

[4] Values from NERC Generator Availability Data System for the 2023 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2023 summer risk period scenarios in the *2023 SRA*.