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Public Counsel – Exhibit 201
Lena M. Mantle
Surrebuttal Testimony
File Nos. EO-2022-0040 & EO-2022-0193

Exhibit No.:	201
Issue(s):	Resource Planning
Witness/Type of Exhibit:	Mantle/Surrebuttal
Sponsoring Party:	Public Counsel
Case No.:	EO-2022-0040 and EO-2022-0193

SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NOS. EO-2022-0040 AND EO-2022-0193

May 27, 2022

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financial Order the Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	)))))	Case No. EO-2022-0040
In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	))))))	Case No. EO-2022-0193

AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Lena M. Mantle, of lawful age and being first duly sworn, deposes and states:

1. My name is Lena M. Mantle. I am a Senior Analyst for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my surrebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Lena M. Mantle
Lena M. Mantle
Senior Analyst

Subscribed and sworn to me this 27th day of May 2022.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI
TIFFANY HILDEBRAND
My Commission Expires
August 8, 2023
Cole County
Commission #15637121

Tiffany Hildebrand
Tiffany Hildebrand
Notary Public

My Commission expires August 8, 2023.

SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NOS. EO-2022-0040 & EO-2022-0193

I. INTRODUCTION

Q. Please state your name.

A. Lena M. Mantle

Q. Are you the same Lena Mantle who previously testified in rebuttal in both Case Nos. EO-2022-0040 and EO-2022-0193?

A. I am.

Q. What is the purpose of your surrebuttal testimony?

A. I am responding to the rebuttal testimony of Missouri Public Service Commission Staff ("Staff") witness J Luebbert regarding his testimony that Empire "replaced" its Asbury generating unit with wind resources. I also provide support for the surrebuttal testimony of Office of the Public Counsel ("OPC") witness Dr. Geoff Marke.

Q. Have Empire's wind projects replaced its Asbury unit?

A. While construction of the wind projects has been completed and the cost will be included in rates soon, and Empire has prematurely retired its 200 MW coal-fired Asbury steam unit when it started building the wind projects, as I explained in my rebuttal testimony, the reliability of the availability of the wind projects to generate electricity to serve load (dispatchability) is much less controllable than that of the Asbury unit. I would not characterize Empire's wind projects as having replaced its Asbury unit.

Q. Do you have independent support for your opinion?

A. Yes. The difference in the dispatchability of differing generation resources is broadly recognized due to the inherent differences in characteristics of the energy sources from which they generate electricity. For example, in its 2021 Long-Term Reliability Assessment the

North America Electric Reliability Corporation's ("NERC") provided as Schedule LMM-S-1 to this testimony the NERC states:

> [Variable Energy Resources ("VERs")] include wind, solar, and run-of-river hydroelectric plants for which electric output can change according to the primary driver (i.e., moving air, sunlight, moving water), resulting in plant output fluctuations on all time scales. Planners and operators must address and prepare for the uncertainty associated with these resources because the magnitude and timing of variable generation output is less predictable than for conventional generation.
>
> Diminished levels of flexible generation--fuel-assured, weatherized, and dispatchable resources--create vulnerabilities to energy shortfalls when extremely hot or cold weather settles over a wide area for extended duration or when weather-dependent generation is impacted by abnormal atmospheric conditions, such as smoke or wind drought:

These quotes show that Empire's wind projects (VERs) have different characteristics from Asbury (conventional generation). They supplement each other, but should not be considered comparable resources that can replace each other. In fact, NERC in this report states:

> Energy risks emerge when variable energy resources (VER) like wind and solar are not supported by flexible resources that include sufficient dispatchable, fuel-assured, and weatherized generation.

And that:

> Reliable operation of thermal generating units and fuel assurance is critically important, especially during extreme weather events.

Q. Is Empire in the Southwest Power Pool where it participates in the SPP's energy market?

A. Yes.

Q. Has the NERC recently addressed energy reliability risk in the SPP?

A. In its long-term reliability assessment section of its report, NERC merely states that SPP's each year's anticipated reserve margin[1] is greater than the reserve margin SPP has determined provides a loss of load expectation for the entire SPP system of 1 day in 10 years.[2] Elsewhere

[1] Reserve margin = (Capacity MW minus forecasted peak MW)/forecasted peak MW.

[2] This analysis does not measure the loss of load expectation for each of SPP's load serving entities, i.e. SPP's loss of load expectation is 1 day in 10 years does not equate to a loss of load expectation of 1 day in 10 years for Empire.

in the report, NERC cautions, "Capacity-based estimates, however, can give a false indication of resource adequacy." This would apply to SPP since its reserve margin is based on forecasted peaks and accredited capacity.

However, NERC looks at more than just the reserve margins of the regional transmission organizations. Regarding energy risks in extreme weather, the NERC states:

> Inadequate winterization of thermal and wind generation in parts of MISO, Southwest Power Pool, and Texas that do not typically experience extreme cold temperatures remains a significant risk in winter reliability until new NERC winterization requirements highlighted in the February 2021 Cold Weather Outages Report are effective. In the meantime, Generator Owners, Generator Operators, and Grid Operators (Reliability Coordinators and Balancing Authorities) in all areas must understand the capabilities that facilities are designed to operate in and incorporate a risk assessment in seasonal operating plans.

Q. Has the NERC assessed SPP's reliability for this summer?

A. Yes, but not in the long-term reliability assessment attached as Schedule LMM-S-1. It reported its assessment in its 2022 Summer Reliability Assessment report attached as Schedule LMM-S-2. There the NERC states:

> 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.

Q. Why is your opinion and the NERC's assessments important for purposes of these securitization cases?

A. The NERC, in its 2021 Long-Term Assessment, makes the following recommendations:

> Regulators and policymakers in risk areas should coordinate with electric industry planning and operating entities to develop policies that <u>prioritize reliability, including those that would promote the development and use of flexible resources and maintain a sustainable and diverse generation mix.</u> (emphasis added)
>
> Regulators and policymakers should review the scope of their resource adequacy requirements to ensure that they <u>address risks of both energy and capacity shortfalls and consider both peak and non-peak demand hours</u>. They should also consider

> limitations from neighboring systems during wide-area, long-duration extreme weather events and potential generator fuel supply limitations. (emphasis added)

In Missouri, resource planning decisions are made by the electric utility, not the regulators. Empire made the decision to retire Asbury and build the wind projects based on its prediction of future energy revenues from the SPP energy market that would provide revenues to its customers and the certainty of a return on not only the new investment but the old retired investment. Reliability was not an Empire priority nor was Empire maintaining a sustainable and diverse generation mix. Empire's reliability objective was to meet the SPP planning reserve margin, with no consideration to how its resources would meet load during both peak and non-peak hours.

Because Empire was imprudent in its resource planning process and did not plan to have resources that would meet its customers' needs, the Commission should not grant total cost recover for the extreme costs Empire incurred during Storm Uri. Also, as OPC witness Dr. Geoff Marke recommends in both his rebuttal and surrebuttal testimonies, the Commission should order a disallowance on the remaining undepreciated balance of the Asbury AQCS, and reject a WACC profit for Empire on the balance of stranded Asbury investment remaining thereafter.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

2021 Long-Term Reliability Assessment

December 2021

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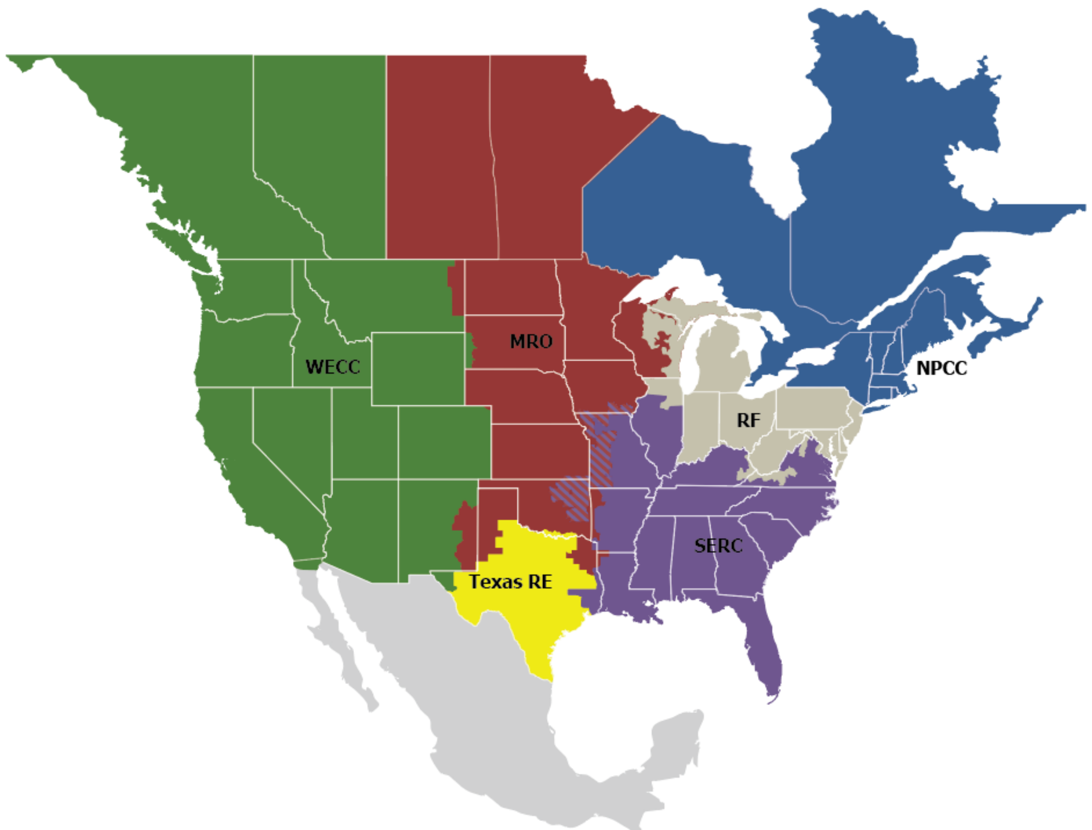
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of 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 and corresponding table below. The multicolored area denotes overlap as some load-serving entities (LSE) participate in one RE while associated Transmission Owners/Operators participate in another. A map and list of the assessment areas can be found in the **Regional Assessments** 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 is a not-for-profit international regulatory authority whose mission is to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, serving more than 334 million people. Section 39.11(b) of the U.S. FERC's regulations provide that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information collected by NERC from the six REs on an assessment area basis to independently assess the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees (Board) subsequently accepted this assessment and endorsed the key findings.

NERC develops the Long-Term Reliability Assessment (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2021 about known system changes with updates incorporated prior to publication. The assessment period for this *2021 LTRA* includes projections for 2022–2031; however, some figures and tables examine data and information for the 2021 year. The assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in **Demand Assumptions and Resource Categories**. Reliability impacts related to physical and cyber security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through the Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electricity industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data and information from each RE are also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each RE, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the **How NERC Defines BPS Reliability s**ection of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] *ERO Reliability Assessment Process Document*, April 2018: https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ERO%20Reliability%20Assessment%20Process%20Document.pdf

In this *2021 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2021. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each RE's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in-service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

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.[7] 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 *LTRA*.

Reading this Report

This report is compiled into two major parts:

- Reliability Assessment of the North American BPS
  - Evaluate industry preparations that are in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Identify emerging reliability issues
  - Focus the industry, policy makers, and the general public's attention on BPS reliability issues
  - Make recommendations based on an independent NERC reliability assessment process
- Regional Reliability Assessment
  - 10-year data dashboard
  - Summary assessments for each assessment area
  - Focus on specific issues identified through industry data and emerging issues
  - Identify regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

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

Executive Summary

This *2021 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next ten years. The *LTRA* also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS.

Governmental policies, changes in comparative resource economics, and customer demand for clean energy are driving the rapidly changing resource mix within the BPS; the BPS has already seen a great deal of change and more is underway. Managing this pace of change presents the greatest challenge to reliability. As the system transitions, changing weather systems present new challenges and fuel becomes inherently less secure. The FERC, NERC, and RE staff report—*The February 2021 Cold Weather Outages in Texas and South Central United States* (*The February 2021 Cold Weather Outages Report)*—highlighted the deadly impacts of these risks if reliability is not prioritized in BPS resource planning and policy considerations.[8]

Prioritizing reliability during the grid's transformation and as governmental policies are developed will support a transition that assures electric reliability in an efficient, effective, and environmentally sensitive manner. However, recognition of the challenges that the system faces during this transition requires action on key matters. Natural gas is the reliability "fuel that keeps the lights on," and natural gas policy must reflect this reality. Furthermore, an increased focus on coordination between the electric power system and the systems that supply it with natural gas must occur. More transmission is necessary to get renewable power to load centers, but it takes time to build high-voltage transmission, and extraordinary siting challenges can be encountered. The shift to more and more inverter-based resources (IBR) brings unique opportunities but also integration challenges that can and must be addressed to assure continued reliability. This is not an argument against the transition but a recognition that, without a collective focus, system reliability faces risk that is inconsistent with electric power's essentiality to the continent's economy as well as the health and safety of its population.

This *2021 LTRA* identifies numerous risks that stakeholders and policymakers need to focus on over the next ten years. While this assessment calls out the assessment areas in the U.S. Western Interconnection and MISO for resource adequacy and energy sufficiency concerns, all Interconnections face reliability challenges. Key findings and recommendations are summarized as follows.

Resource Adequacy and Energy Risks

Most areas are projecting to have adequate resource capacity to meet annual peak demand associated with normal weather. Capacity shortfalls, where they are projected, are the result of future generator retirements that have yet to be replaced with new resource capacity. Capacity-based estimates, however, can give a false indication of resource adequacy. Energy risks emerge when variable energy resources (VER) like wind and solar are not supported by flexible resources that include sufficient dispatchable, fuel-assured, and weatherized generation:

- In the **Midcontinent Independent System Operator (MISO)** area, a reserve margin shortfall previously reported is advancing from 2025 to 2024. MISO could face the retirement and resultant loss of over 13 GW of resource capacity over the 2021–2024 period. At this level of retirements, resource additions must increase beyond current projections to avoid a capacity shortfall in 2024. The retirement of these traditional resources also accelerates the change in resource mix and punctuates the urgency for implementing resource adequacy and energy sufficiency initiatives in the area.
- In the **California-Mexico (CA/MX) part of WECC**, the planned retirement of the Diablo Canyon Power Plant contributes to declining reserve margins in the area beginning in 2026. However, energy risks are present today as electricity resources are insufficient to manage the risk of load loss when wide-area heat events occur. Risk is most acute in late afternoon since there are energy limitations as solar photovoltaic (PV) resource output diminishes. Energy analysis shows up to 10 hours of load loss beginning in 2022 and as much as 75,000 MWh of unserved energy in extreme conditions in 2024. Flexible resources that can be dispatched to counter solar PV behavior and be relied upon with assured fuel supplies are needed to reduce the load-loss risk and serve energy demand in all seasons and time periods. Recent California Public Utilities Commission actions to boost capacity at the Aliso Canyon natural gas storage field is an encouraging step toward firming up fuel for flexible generation capacity in California.
- The **U.S. Northwest and Southwest parts of WECC** have increasingly variable resource profiles, raising the risk of energy shortfalls. Energy analysis indicates 23 load-loss hours in the Northwest in 2022. The Southwest also faces potential load-loss hours beginning in 2024. As resource planners in parts of the Western Interconnection turn increasingly to external transfers for sufficient capacity and energy to meet demand, the need for regional coordination and resource adequacy planning is growing.

[8] https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

Energy Risks in Extreme Weather

Wide-area and long duration extreme weather events driven by climate change threaten reliability when electricity demand is driven above forecasts and supplies are reduced. Diminished levels of flexible generation--fuel-assured, weatherized, and dispatchable resources--create vulnerabilities to energy shortfalls when extremely hot or cold weather settles over a wide area for extended duration or when weather-dependent generation is impacted by abnormal atmospheric conditions, such as smoke or wind drought:

- Flexible generation resource levels have fallen in **Texas, California, and the U.S. Northwest** to the point that projected peak demand cannot be met without some combination of weather-dependent wind and solar generation along with external transfers. Changes in climate that drive extreme weather conditions raise the likelihood for one or more of these resources to fall short of forecasts, leaving other resources to make up the gap, or load will need to be shed.
- Natural gas infrastructure that supports electricity generation in **New England**, **California**, **and the U.S. Southwest** is susceptible to disruptions with the potential to affect winter reliability. Generators that lack firm natural gas delivery can have their supplies curtailed when the demand for natural gas peaks. In New England, limited natural gas pipeline capacity leads to a reliance on fuel oil and imported liquefied natural gas (LNG) to meet winter peak loads. Limited natural gas pipeline capacity and lack of redundancy is a concern for electric reliability in normal winter and a serious risk in a long-duration, extreme cold conditions.
- Inadequate winterization of thermal and wind generation in parts of **MISO, Southwest Power Pool, and Texas** that do not typically experience extreme cold temperatures remains a significant risk in winter reliability until new NERC winterization requirements highlighted in the *February 2021 Cold Weather Outages Report* are effective. In the meantime, Generator Owners, Generator Operators, and Grid Operators (Reliability Coordinators and Balancing Authorities) in all areas must understand the capabilities that facilities are designed to operate in and incorporate a risk assessment in seasonal operating plans.

Risks from Inverter-Based Resource Performance Issues

The latest industry projections included in this *2021 LTRA* provide further evidence of the rapid growth of IBRs on the BPS and distribution networks; these include most solar and wind as well as new battery or hybrid generation. Since the *2020 LTRA*, the nameplate capacity projections of solar projects in all stages of development has increased from 390 GW to 504 GW for the next 10 years. Wind projects are projected to total 360 GW of nameplate capacity over the next 10 years, up from 250 GW since the *2020 LTRA* projection. Some IBR performance issues have been significant enough to result in grid disturbances that affect the reliability of the BPS:

- IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls, not mechanical characteristics. Planning studies and operating models must accurately account for these newer resource types in growth areas in order to control the BPS during disturbances.
- Industry experience with unexpected tripping of a number 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 the Odessa disturbance in May and June of 2021 in Texas. In both cases the lack of IBR ride-through capability took minor system disturbances and unnecessarily amplified them into major disturbances.

Implications and Recommendations

To ensure resource adequacy and energy sufficiency as the grid transforms and to reduce the exposure to energy shortfalls in extreme weather, the resource planning community of stakeholders needs to keep reliability at the forefront of its actions. Focus should include the following areas:

- Sufficient flexible resources are needed to support increasing levels of variable generation uncertainty. Until storage technology is fully developed and deployed at scale (which cannot be presumed to occur within the time horizon of this LTRA), natural-gas-fired generation will remain a necessary balancing resource to provide increasing flexibility needs. Resource planning and policy decisions must ensure that sufficient balancing resources are developed and maintained for reliability.
- With increased reliance on natural gas comes the need to deeply understand natural gas and electric system interdependencies. Improved coordination between natural gas and electricity is required. The lack of that coordination was a major contributor to the devastation in ERCOT during winter storm Uri in 2021. The natural gas system was not built or operated with electric reliability as the first concern. Electric grid planners must understand natural gas system vulnerabilities to assess contingencies and plan for grid reliability. Moreover, NERC believes that the regulatory structure and oversight of natural gas supply for electric generation needs to be rethought to assure reliable fuel supply for electric generation to support the reliable operation of the BPS.
- Extreme weather is a core condition to consider in resource planning. Extreme weather events in California, Louisiana, and Texas underscore the need to reconsider how to think about capacity. A comprehensive resource planning construct must focus attention on energy sufficiency with the understanding that capacity alone does not provide for reliability unless the fuel behind it is assured even in extreme weather. Owners of BPS generators and

transmission facilities must keep focus on weatherization while grid operators prepare and implement seasonal operating plans that account for generator performance and fuel supply risks in extreme conditions so that past failures are not repeated.

- Reliably integrating IBRs require owners and operators to pay attention to modeling and coordination needs so that planning studies and operating models accurately account for new resource types. Furthermore, heightened cyber security awareness and risk-reduction engineering should be pursued to reduce attack surfaces and mitigate reliability and security concerns as IBRs proliferate. Planning approaches that build in robust cyber security and reduce risk exposure is not solely an IBR integration issue; but rather an important element of a broader strategy to reduce cyber security risks to the reliable operation of the BPS.
- Distributed energy resources (DER) growth promises both opportunity and risks for reliability. Increased DER penetrations can improve local resilience and offset peak electric demand on the BPS. However DER can also increase variability and uncertainty in demand and therefore requires careful attention in planning for resource adequacy and energy sufficiency. DERs also increase the complexity of operating the BPS as operators often lack visibility into the effect of the DER on loads. Consequently, there is an immediate concern to ensure that data transfer, models, and information protocols are in place to support BPS planners and operators. DER aggregators will also play an increasingly important role to BPS reliability in the coming years. Increasing DER participation in wholesale markets should be considered in connection with potential impacts to BPS reliability, contingency selection, and how any reliability gaps might be mitigated.

Key Findings

For more information on each key finding, see the **Detailed Key Findings** section.

Key Finding 1 (Reserve Margins): Anticipated reserves fall below the Reference Margin Level (RML) in MISO beginning in 2024, NPCC-Ontario beginning in 2025, and California (WECC-CA/MX) beginning in 2026. For all other areas, anticipated capacity reserves are above their respective RMLs for the first five years of this assessment period, indicating that there will be sufficient electric resources to meet peak demand. Note, however, that this reserve margin analysis does not explicitly account for resource energy limitations due to fuel uncertainty. Details include the following:

- MISO could face the loss of over 13 GW of resource capacity from 2021 to 2024 based on its annual survey of members. These unconfirmed retirements include 10.5 GW of coal-fired and 2.4 GW of natural-gas-fired generation. A capacity shortfall of over 560 MW in 2024 would result if all of these unconfirmed retirements were to occur without additional new generation resources (on top of the 8 GW already in development for interconnection by 2024).
- The planned retirement of the 2,200 MW Diablo Canyon Power Plant generating stations in 2024 and 2025 contributes to a projected capacity shortfall in WECC-CA/MX beginning in 2026. Reserve margins in WECC-CA/MX are also declining because of the energy limitations of solar PV resources at the peak demand hour, which occurs later in the day when solar PV resource output is lower.
- In Ontario, results of the Independent Electricity System Operator (IESO) capacity auction held in December 2020 as well as the delayed retirement of a nuclear generating station have alleviated near-term capacity concerns identified in the *2020 LTRA.* IESO expects to meet the 2025 reserve margin shortfall projected in this year's assessment with capacity obtained through a series of recently announced procurement mechanisms and increased participation in the capacity auction.
- NPCC-Maritimes reserve margins fluctuate around Reference Margin Level over the assessment period; results of annual and short-term capacity procurements are expected to mitigate these small shortfalls.

Key Finding 2 (Energy Risks): Since the publication of the ERO's probabilistic assessment (ProbA) in 2020, additional analysis indicates that risk of load loss and energy shortfalls persist in the Western Interconnection and MISO areas. Details include the following:

- The 2020 ProbA identified elevated load-loss risk in MISO, Saskatchewan (MRO-SaskPower), and the Northwest-Rocky Mountain (WECC-NWPP-RMRG), it also identified high risk in WECC-CA/MX for 2022 and beyond. While conditions in MRO-SaskPower have improved, concerns remain in the other areas.
- The risk of unserved energy and loss of load hours (LOLH) in MISO in the near-term horizon has increased due to the declining resources since the 2020 ProbA. Reserve margins could fall below the Reference Margin Levels beginning in 2024. This indicates that, without additional resources from the interconnection planning queue or other sources, the projected resources in MISO after 2023 are not sufficient to meet a 1-day-in-10 year loss of load criteria under current forecasts.
- The two largest U.S. assessment areas in the Western Interconnection—California/Mexico and the Northwest-Rocky Mountain (WECC-NWPP-US & RMRG)—have potential for high load-loss hours and energy shortfalls for 2022 and beyond. In updated probabilistic studies of demand and resource scenarios for 2022, WECC-CA/MX shows 10 potential hours of load loss, and the NWPP-US & RMRG area shows 23. Higher load-loss metrics were seen in the 2024 study year for all U.S. areas of the Western Interconnection.

Key Finding 3 (Extreme Weather Risks): Parts of North America are exposed to energy shortfall risks in the near-term assessment period from wide-area and long duration extreme weather events like the 2020/2021 western heat wave and winter storm Uri in 2021. Details include the following:

- Extreme weather can cause challenging grid operating conditions by both diminishing the supply of electricity and driving actual demand above forecasts. Near-term demand forecasts, resource projections, and other trends suggest that even parts of North America that are considered resource adequate at the traditional peak hour evaluation are becoming increasingly exposed to energy shortfall risks in extreme weather events.
- The increasing volatility and uncertainty of electricity demand makes accurate load forecasting a challenge, increasing the risk that Balancing Authorities (BA) may be unprepared for the peak demands that can accompany extreme weather events. In extreme temperatures, areas with relatively high seasonal load forecast uncertainty (LFU) and low Planning Reserve Margins (PRM) are at risk of capacity shortfall: WECC-CA/MX and NWPP-US & RMRG areas near-term summer projections fall into this category.
- Areas that rely on VER or imports to meet peak or other high-risk periods face greater risk in wide-area, long-duration weather events and when weather-dependent generation is impacted by abnormal atmospheric conditions, such as smoke or wind drought. Where extended drought increases the risk of wildfires, transmission lines can be impacted, curtailing electricity transfers that are needed to serve demand. Texas, California, and the U.S. Northwest currently or in the near term depend on a combination of transfers, wind, and

solar generation to meet projected peak demand. MISO and the U.S. Southwest are approaching similar thresholds in near-term projections. In the event that one or more of these resources fall short of forecast at peak conditions, other resources must make up the gap, or load will need to be shed.

- Reliable operation of thermal generating units and fuel assurance is critically important, especially during extreme weather events.

Key Finding 4 (Frequency Response): Frequency response is expected to remain adequate through 2023. Details include the following:

- Despite increasing amounts of asynchronous resources and less inertia due to retirement of rotating generation, each of the four Interconnections expect to have adequate and diverse sources of frequency response, and all have a low likelihood of activating under-frequency load shedding (UFLS) schemes.
- Maintaining Interconnection frequency within acceptable boundaries following the sudden loss of generation or load can be accomplished by using the control functions of inverters, which includes energy storage and load-shedding relays; this is generally known as fast frequency response (FFR). The application of FFR is expected to continue and support frequency when synchronous inertia is insufficient.
- Future changes to the resource mix will continue to impact the level of inertia.

Key Finding 5 (Resource Mix Changes): VERs continue to grow and thermal resource capacity declines in most areas throughout this assessment period; as a result, increased attention on planning and operating a more complex resource mix is required:

- Projects to develop solar and wind generation for the BPS continue to grow in the interconnection planning queues. Since the *2020 LTRA*, the nameplate capacity of solar projects in all stages of development has increased from 390 GW to 504 GW for the next 10 years. Wind projects are projected to total 360 GW of nameplate capacity over the next 10 years, up from 250 GW since the *2020 LTRA* projection.
- Texas RE-ERCOT, PJM, and MISO have the most solar capacity in planning. MISO, NPCC-New England, PJM, SPP, and Texas RE-ERCOT have the most wind capacity in planning.
- Existing battery resources and projects in interconnection queues at various stages of development through 2024 now total over 113 GW—a substantial increase from the 47 GW reported for the same period in the *2020 LTRA*.
- DER growth continues with cumulative solar PV DERs expected to reach over 60 GW by the end of this 10-year assessment period. A total of 15 of the 20 assessment areas expect to double their total solar DER footprint by 2031. This growth highlights the need for the ERO as well as planners and operators in growth areas to take actions that ensure planning processes and operating measures are in place to ensure reliability.
- In many areas, VERs are increasingly important to meet electricity demand. Operators must have flexible resources, including adequate dispatchable, fuel-assured, and weatherized generation, at their disposal. This is especially true in areas with high levels of variable generation to avoid shortfalls when VER output is insufficient to meet demand.[9]
- IBRs, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. Maintaining a reliable system as the penetration of IBRs increase requires planners and operators to be cognizant of potential disturbance-related performance issues.

Recommendations for Key Findings

- Regulators and policymakers in risk areas should coordinate with electric industry planning and operating entities to develop policies that prioritize reliability, including those that would promote the development and use of flexible resources and maintain a sustainable and diverse generation mix.
- Regulators and policymakers should review the scope of their resource adequacy requirements to ensure that they address risks of both energy and capacity shortfalls and consider both peak and non-peak demand hours. They should also consider limitations from neighboring systems during wide-area, long-duration extreme weather events and potential generator fuel supply limitations.
- Industry planners should pay close attention to the ramping and load-following requirements for their system as VERs increase as well as to commit flexible resources to meet the system reliability needs.
- The ERO and industry should develop processes and techniques to assess the adequacy of energy supplies and ensure that the changing resource mix can meet operational needs. Capacity-based resourced adequacy measures and criteria (e.g., PRMs and RMLs) do not ensure that sufficient amounts of energy will be available for a variety of potential weather and environmental conditions. Energy metrics, such as expected unserved energy (EUE)

[9] Flexible resources refer to dispatchable conventional as well as dispatchable variable resources, energy storage devices, and dispatchable loads.

levels, are also an important part of assessing BPS reliability. The ERO and industry should develop tools to incorporate energy considerations into planning and operational assessments. They should also explore desired energy performance levels and evaluate NERC Reliability Standards for enhancements necessary to ensure energy adequacy in planning and operating time horizons.

- The ERO and industry should continue to strengthen their winterization and cold weather preparedness and coordination as well as enhance reliability standards to reduce the risks to electric reliability from extreme winter weather events. Regulators and policymakers should adopt policies that promote hardening electric generation and transmission facilities as well as fuel supplies to operate in specified temperatures for their areas.[10]
- Generator Operators and Generator Owners as well as BAs should increase coordination on seasonal operating plans. BAs must be aware of the performance expectations of all generators at forecast ambient conditions, and the BAs' plans should only depend upon generators that have a reasonable expectation of performing during forecast conditions.
- Industry planners should update interconnection agreements to address the performance specifications for IBRs covered in the NERC reliability guidelines to ensure that all resources are consistently and effectively being interconnected to the BPS.[11] FERC should also update its *pro forma* interconnection agreement for large and small generators to include IBR performance specifications. These updates should also be accompanied by clear requirements for accurate modeling and sufficiently detailed studies during time of interconnection, and they should include electromagnetic transient (EMT) studies where necessary.
- The ERO should continue advancing the efforts to modernize NERC Reliability Standards to account for IBR performance characteristics. This includes promptly reviewing industry's voluntary application of guidance and recommended practices contained in NERC Reliability Guidelines for IBR performance. Where reliability gaps are identified, NERC should develop standard requirements that support the delivery of achievable performance capabilities from BPS-connected IBRs that benefit system reliability.
- The ERO and industry should continue to focus on the improvements needed in the area of modeling and studies for reliably integrating IBRs into the BPS. This includes verifying that IBR models used for steady state and dynamic power systems analysis agree with the as-built, plant-specific settings, controls, and behaviors of the facility. The ERO and industry should also develop techniques and procedures for more advanced EMT studies capable of identifying the full scope of abnormal performance issues during the interconnection study process. These issues can be corrected before the plants are connected to the grid.
- NERC should continue working with the Eastern, Western, and Texas Interconnection study groups to assess forward-looking Interconnection frequency response. The analysis should continue to evolve and reflect low-inertia conditions that may be anticipated by the current and future generation resource mix.

[10] For specific details on recommendations for cold weather grid operations, see the findings and recommendations of the Joint FERC/NERC/Regional Entity Inquiry into the February 2021 cold weather event: https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

[11] *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources:* https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

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

Operating Reliability: The ability of the electricity system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators can and should take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[12]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The Bulk Electric System (BES) is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[13] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[14] which is defined by the following characteristics.

Adequate Level of Reliability: It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:

- The BES does not experience instability, uncontrolled separation, cascading,[15] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[16]
- BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
- BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
- Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.
- Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

[12] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: https://www.nerc.com/files/glossary_of_terms.pdf
[13] https://www.nerc.com/pa/RAPA/Pages/BES.aspx
[14] https://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_Technical_Report_clean.pdf
[15] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."
[16] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

Detailed Key Findings

There are five detailed key findings in this section of the *2021 LTRA* (a summary of each can be found in the previous section): **Key Finding 1** (Reserve Margins), **Key Finding 2** (Energy Risks), **Key Finding 3** (Extreme Weather Risks), **Key Finding 4** (Frequency Response), and **Key Finding 5** (Resource Mix Changes).

Key Finding 1 (Reserve Margins)

Anticipated reserves fall below the RML in MISO beginning in 2024, NPCC-Ontario beginning in 2025, and WECC-CA/MX beginning in 2026. There is sufficient electricity resource capacity in all other areas.

Key Points

- MISO could face the loss of over 13 GW of resource capacity from 2021–2024 based on its annual survey of members; these unconfirmed retirements include 10.5 GW of coal-fired generation and 2.4 GW of natural-gas-fired generation. A capacity shortfall of over 560 MW in 2024 would result if all of these unconfirmed retirements were to occur without additional new generation resources (on top of the 8 GW already in development for interconnection by 2024).
- The planned retirement of the 2,200 MW Diablo Canyon Power Plant generating stations in 2024 and 2025 contributes to a projected capacity shortfall in WECC-CA/MX beginning in 2026. Reserve margins in WECC-CA/MX are also declining because of the energy limitations of solar PV resources at the peak demand hour, which occurs later in the day when solar PV resource output is lower.
- In NPCC-Ontario, results of the IESO's capacity auction held in December 2020 as well as the delayed retirement of a nuclear generating station have alleviated the near-term capacity concerns identified in the *2020 LTRA.* IESO expects to meet the 2025 reserve margin shortfall projected in this year's assessment with capacity obtained through a series of recently announced procurement mechanisms and increased participation in the capacity auction.
- NPCC-Maritimes reserve margins fluctuate around the Reference Margin Level over the assessment period; results of annual and short-term capacity procurements are expected to mitigate these small shortfalls.

For the majority of the BPS, PRMs appear sufficient to maintain reliability during the long-term, 10-year horizon. However, there are challenges facing the electricity industry that may shift current industry projections, constrain resources from delivering expected energy and capacity, and/or otherwise cause NERC's assessment to change (see **Key Finding 5 (Resource Mix Changes)**).

Where markets exist, signals for new capacity must be effective for planning purposes and reflect the lead times necessary to construct new generation, associated transmission, and natural gas infrastructure if needed. Although generating plant construction lead times have been significantly reduced, environmental permitting for energy infrastructure and transmission planning and approval still require significant lead times.[17]

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this *LTRA* are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRM relative to its RML—a "target" or requirement based on traditional capacity planning criteria. For a description of each assessment area's RMLs refer to **Table 10.** A The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss of load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (such as wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity (Refer to **Table 9** in **Key Finding 5 (Resource Mix Changes)** to see the on-peak capacity contribution of existing wind and solar resources for each assessment area).

On the basis of the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The Anticipated Reserve Margin (ARM) is greater than RML.

Marginal: The ARM is lower than the RML and the PRM is higher than RML.

Inadequate: The ARM and Prospective PRMs are less than the RML and Tier 3 resources are unlikely to advance.

[17] Capacity supply and PRM projections in this assessment do not necessarily take into account all generator retirements that may occur over the next 10 years or account for all replacement resources explicitly linked with potential retiring resources. While some generation plants have already announced and planned for retirement, there are still many economically vulnerable generation resources that have not determined and/or announced their plans for retirement.

As shown in **Figure 1**, the ARM in all assessment areas is above the RML in 2026 with the exception of MISO, NPCC-Ontario, and WECC-CA/MX.

The arrival of COVID-19 in North America in 2020 has introduced additional uncertainty into future electricity demand forecasts and PRM projections. Prior to Summer 2020, when government stay-at-home orders and societal response were at their highest, some areas reported as much as 15% drop in peak demand. However, these observed demand impacts varied across North America and were negligible in some areas. Electricity demand forecasts used in resource adequacy planning account for long-term trends in electricity usage based on inputs, such as weather patterns, economic growth projections as well as EE initiatives and trends. Pandemic impacts can affect the accuracy of demand projections in the near term and have the potential to either exacerbate or alleviate planning reserve shortfalls in areas that are below or near RMLs. PRMs can also be affected by supply chain issues that disrupt the planned addition of new resources. Over time, demand forecast models can be expected to better account for economic and customer behavior changes that may have or could occur as a result of the pandemic.

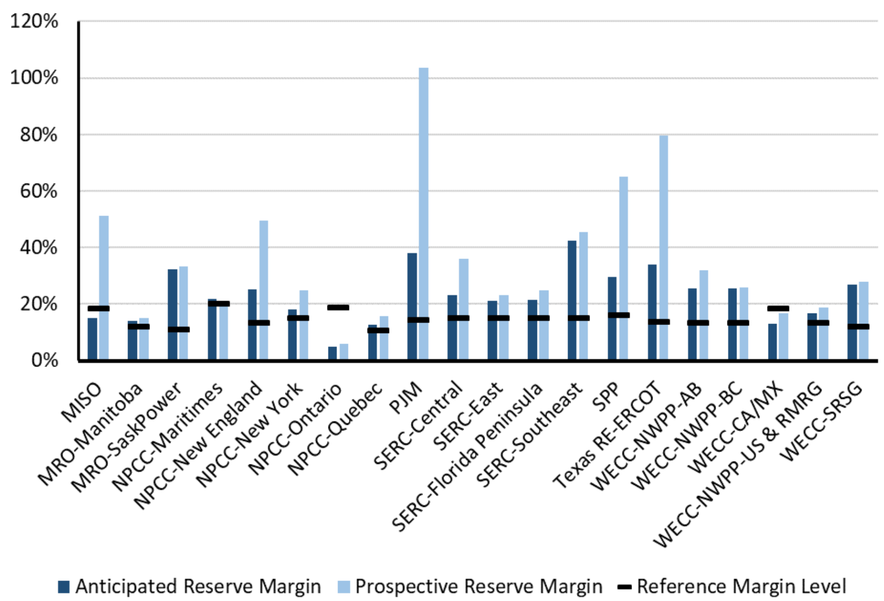


Figure 1: Anticipated and Prospective Reserve Margins for 2026 Peak Season by Assessment Area

NERC PRM Categories

Anticipated Resources

- **Existing-Certain Generating Capacity**: capacity expected to be available to serve load during the peak hour with firm transmission
- **Tier 1 Capacity Additions:** capacity either under construction or has received approved planning requirements
- **Firm Capacity Transfers (Imports minus Exports):** transfers with firm contracts
- **Confirmed Retirements:** capacity with formalized and approved plans to retire

Prospective Resources

- **Anticipated Resources:** as described above
- **Existing-other Capacity:** capacity that could be available to serve load during the peak hour but lacks firm transmission and could be unavailable during the peak for a number of reasons
- **Tier 2 Capacity Additions:** capacity that has been requested but approval for planning requirements not received
- **Expected (nonfirm) Capacity Transfers (imports minus exports):** transfers without firm contracts but a high probability of future implementation
- **Unconfirmed Retirements:** expected to retire based on the result of an assessment area generator survey or analysis (capacity aggregated by fuel type)

The results of NERC's risk determination for all assessment areas are shown in **Table 1**. NPCC-Ontario and WECC-CA/MX are identified as "Inadequate," MISO and NPCC-Maritimes as "Marginal," and all other areas identified as "Adequate" through 2026.[18] See the **Regional Assessments** section for demand and supply trends through 2031.

PRMs in MRO-MISO

As decarbonization efforts progress in MISO states, the next decade is expected to bring significant changes to the generation fleet. MISO planners observe that a drop in reserve margins occurred between 2010 and 2015 as new emissions regulations were adopted, and similar effects may now be taking place.

[18] *Note about NPCC-New York: While the total resources calculation is above the LTRA Reference Margin Level of 15%, there is no PRM criteria in New York.

Table 1: NERC's Risk Determination of All Assessment Areas 5-Year Projected Reserve Margins				
Assessment Area	2026 Peak Anticipated Reserve Margin	2026 Reference Margin Level	Expected Capacity Surplus or Shortfall (MW)	Assessment Results Though 2026
MISO	15.8%	18.3%	-2,965	Marginal
MRO-Manitoba	14.0%	12.0%	94	Adequate
MRO-SaskPower	32.3%	11.0%	782	Adequate
NPCC-Maritimes	22.0%	20.0%	107	Marginal
NPCC-New England	25.1%	13.5%	2765	Adequate
NPCC-New York	18.3%	15.0%	992	Adequate
NPCC-Ontario	4.9%	18.9%	-1,161	Inadequate (2026)
NPCC-Québec	13.7%	10.8%	1,070	Adequate
PJM	38.0%	14.4%	33,772	Adequate
SERC-Central	23.1%	15.0%	3,216	Adequate
SERC-East	21.3%	15.0%	2,708	Adequate
SERC-Florida Peninsula	21.4%	15.0%	3,213	Adequate
SERC-Southeast	42.5%	15.0%	12,598	Adequate
SPP	29.5%	16.0%	7,179	Adequate
Texas RE-ERCOT	34.1%	13.75%	16343	Adequate
WECC-NWPP-AB	25.4%	13.2%	1,475	Adequate
WECC-NWPP-BC	25.7%	13.2%	1,163	Adequate
WECC-CA/MX	12.9%	18.6%	-3,264	Inadequate (2026)
WECC-NWPP-US & RMRG	16.9%	13.5%	2,452	Adequate
WECC-SRSG	27.0%	12.2%	3,907	Adequate

The projected five-year ahead ARMs indicate a regional shortfall below the RML in 2024 and beyond (see **Figure 2**). In the *2020 LTRA*, MISO was not expected to fall below the RML until 2025.

MISO's anticipated resources—a key factor in reserve margins—are based on an annual survey of MISO members.[19] This survey conservatively identifies potential generation retirements that have not been formally declared or entered the retirement process and are thus unconfirmed. Based on MISO's 2021 survey of members, MISO anticipates the loss of over 13 GW of resources from 2021 to 2022. These unconfirmed retirements include 10.5 GW of coal-fired generation and 2.4 GW of natural-gas-fired generation. A capacity shortfall of over 560 MW in 2024 would result if all of these unconfirmed retirements were to occur without additional new generation resources (on top of the 8 GW already expected to interconnect by 2024). Prospective resources, which contribute to the Prospective Reserve Margin shown in **Figure 2** but have yet to complete the interconnection agreement process, will need to materialize to meet the Reference Margin Level during the five-year period and avoid on-peak capacity shortfalls with these retirement assumptions.

MISO planners note that previous iterations of the Organization of MISO States (OMS)-MISO survey have also indicated future year shortfalls, and the survey results provide a mechanism for correction.[20] The assessments provide a range of possible resource adequacy outcomes at a specific snapshot in time. Through coordination between MISO, member state utility commissions, and stakeholders, past shortfall predictions have not come to pass. Based on responses from over 97% of MISO load areas, the 2021 OMS-MISO survey results project more capacity for the 2022 summer than was projected in the prior year, with between 3.4–13.9 GW of capacity in excess of the 2022 regional summer peak PRM.

[19] https://www.misoenergy.org/stakeholder-engagement/committees/oms-miso-survey-webinar/
[20] https://www.misoenergy.org/stakeholder-engagement/committees/oms-miso-survey-webinar/

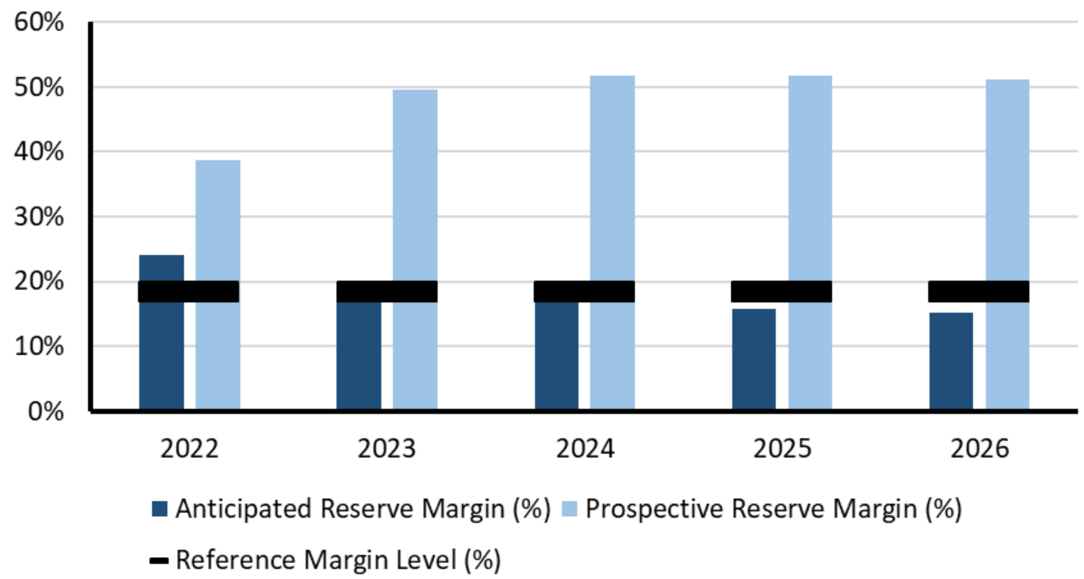


Figure 2: MISO Five-Year Projected Reserves (ARM and PRM)

Over the past several years, the near-term ARMs have been consistently above the current RML of 18.3% as shown in **Figure 3**. Note: Projections are Year 1 projections from prior LTRAs; for example, the 2011 value is based on the *2010 LTRA's* 2011 projection.

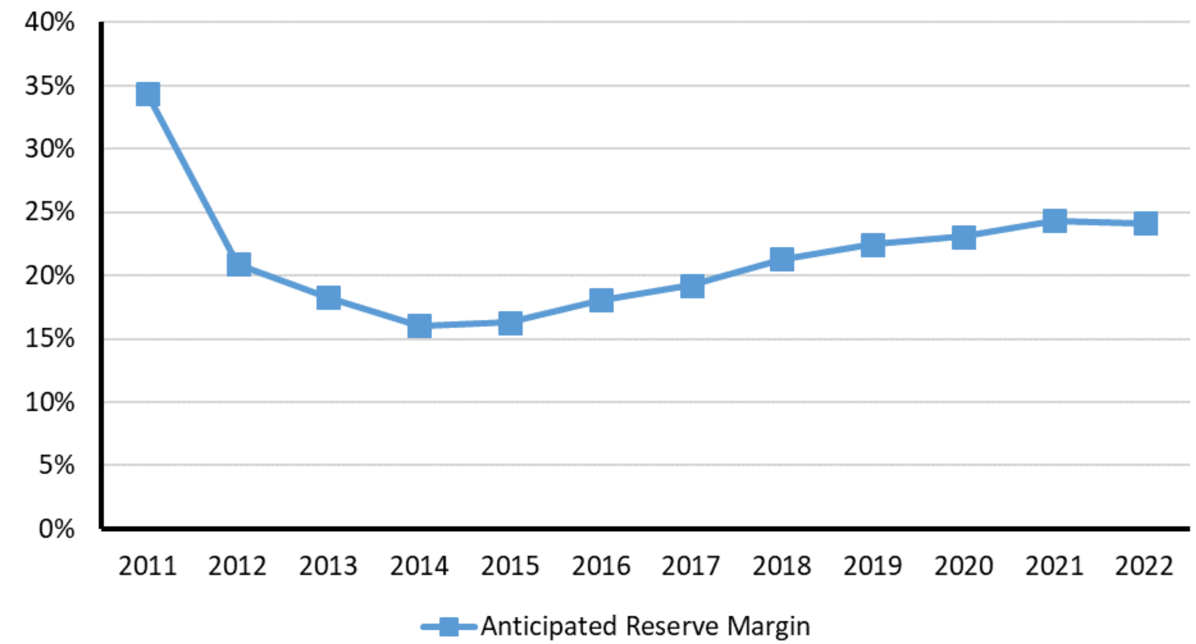


Figure 3: MISO Historical Projected Reserves Margins

PRMs in WECC-CA/MX

The ARM and PRM fall below the RML in WECC-CA/MX beginning in 2026 (see **Figure 4**). The California Public Utilities Commission has directed utilities to procure capacity to make up for shortfalls or anticipated tight peak hour conditions to address energy concerns in the short-term.[21] The 11.5 GW of directed new procurement energy resources are expected to come on-line between 2023 and 2026 to meet energy goals set forth by California.

[21] California Public Utilities Commission Orders Historic Clean Energy Procurement To Ensure Electric Grid Reliability and Meet Climate Goals: https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-orders-clean-energy-procurement-to-ensure-electric-grid-reliability

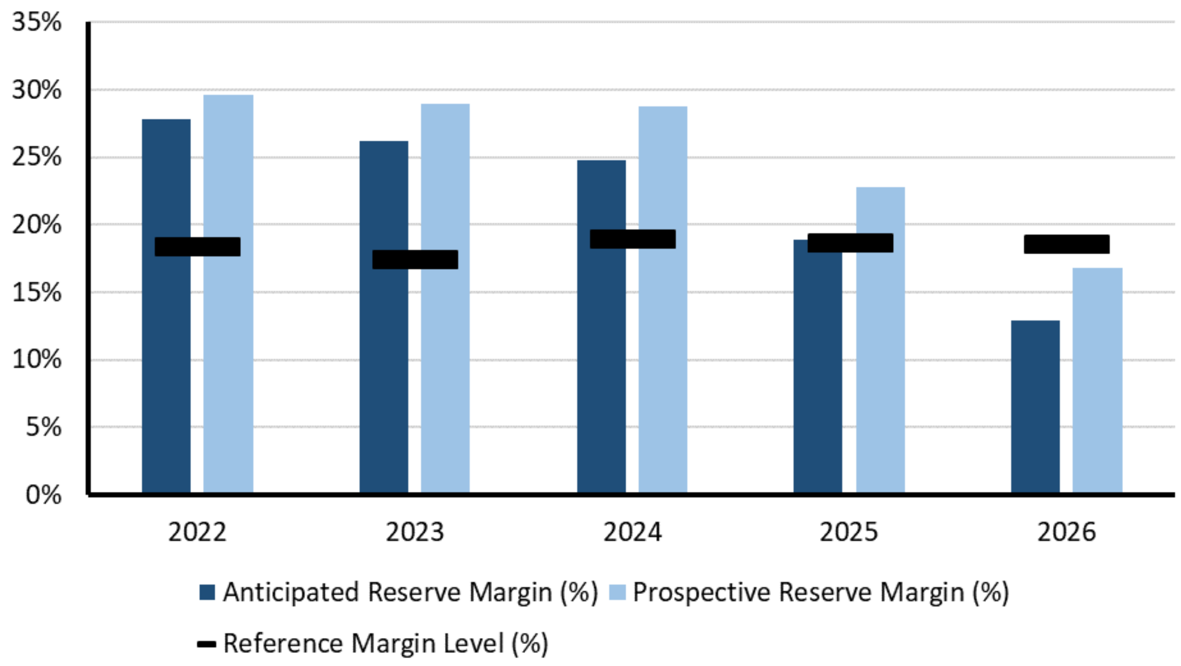


Figure 4: WECC-CA/MX Five-Year Projected Reserves (ARM and PRM)

PRMs in NPCC-Ontario

The ARMs in NPCC-Ontario fall below the RML in 2025 and beyond (see **Figure 5**). In the *2020 LTRA*, Ontario's ARM was expected to fall below the RML in 2022 and beyond due to planned retirements and the nuclear refurbishment program; these planned nuclear outages are a significant contributor to the reserve margin. More resources are needed when nuclear resources are off-line due to the high availability and capacity factor of nuclear generators compared to the other resources that may replace them. To address resource adequacy concerns, the IESO developed its resource adequacy framework.[22] This is a multi-pronged approach for addressing reliability needs and includes a commitment to continue and grow the targets for its capacity auction, a series of medium-term requests for proposals (initial engagement began in Summer 2021), and a long-term request for proposal that targets new-build resources. Short-term capacity concerns from the *2020 LTRA* were alleviated by the IESO's capacity auction held in December 2020 as well as the delayed retirement of a nuclear generating station.

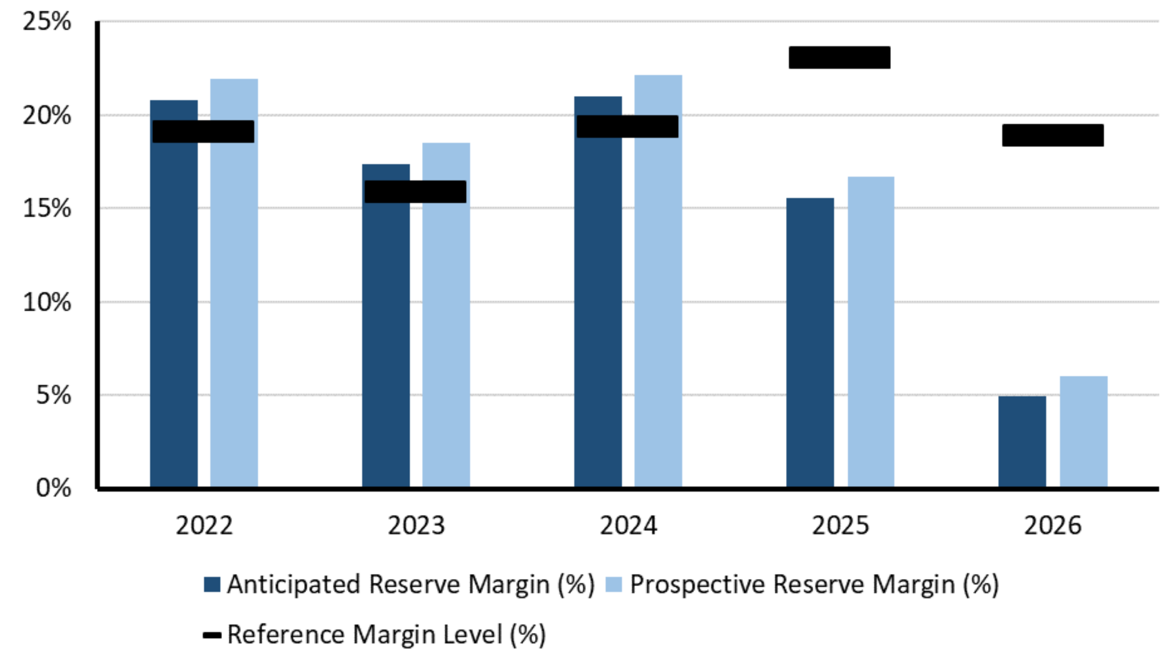


Figure 5: NPCC-Ontario Five-year Projected Reserves (ARM and PRM)

PRMs in NPCC-Maritimes

The ARMs in NPCC-Maritimes fall slightly below the RML for the 2022–2023 winter period (see **Figure 6**). An increase in the winter peak hour demand forecast, reduction in the achievable EE and conservation forecast, and planned retirement of two units at an oil-fired thermal generating station of 40 MW in year 2022 at Prince Edward Island collectively contribute to the reserve margins falling below the reference level. Contributions from prospective resources help to reduce the gap but still fail to meet the 20% RML. The ARM for NPCC-Maritimes returns above the RML for the remainder of the five-year ahead period, but the PRM drops below the RML for 2024 winter season due to anticipated retirements.

A long-term firm energy contract is in place with a neighboring jurisdiction to buy a minimum of 2 TWh/year until 2030 and then 2.5 TWh/year until 2040. This, along with the ability to purchase energy in day ahead and real-time markets, will assist in meeting the RML for the first five years.

[22] IESO Resource Adequacy Engagement: https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Resource-Adequacy-Engagement

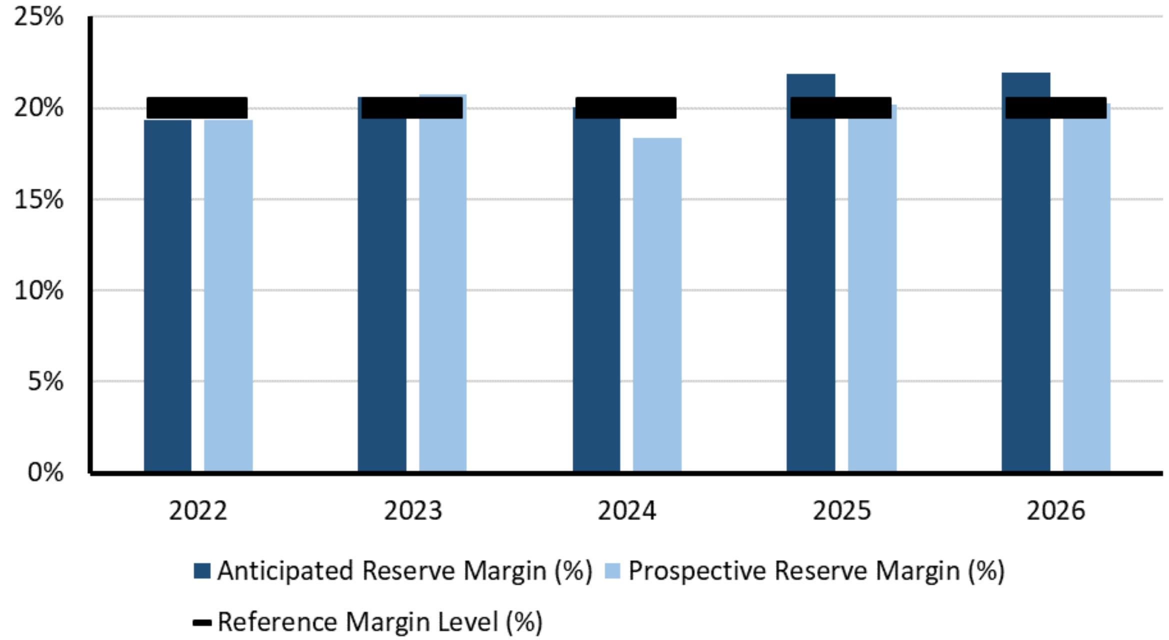


Figure 6: NPCC-Maritimes Five-Year Projected Reserves (ARM and PRM)

PRMs in Texas RE-ERCOT

NERC's *2019 LTRA* and other reports published before the *2019 LTRA* have identified reliability concerns with PRMs in Texas RE-ERCOT. Beginning in 2010, a downward trend in reserve margins led to scarce resources during the peak as well as less operating flexibility (see **Figure 7**). To some extent, this is an expected outcome of managing resource adequacy through an energy-only market construct.[23] However, generation resources have been added and more are in development for connection during the next two years of the assessment period, helping to reduce concerns of resource shortfalls. The ARM is projected to stay above the RML of 13.75% through 2026 (see **Figure 8**).

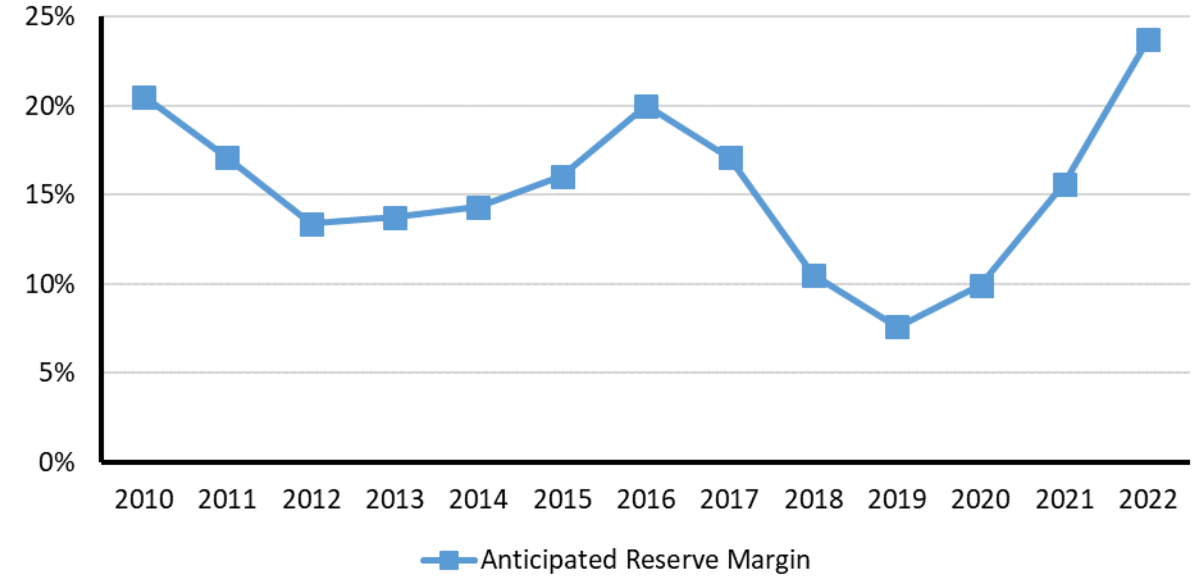


Figure 7: Texas RE-ERCOT Historical Projected Reserve Margins*

[23] Energy-only markets pay resources only when they provide energy on a day-to-day basis. Conversely, capacity markets aim to ensure resource adequacy by paying resources to commit capacity for delivery years into the future in addition to energy payments.

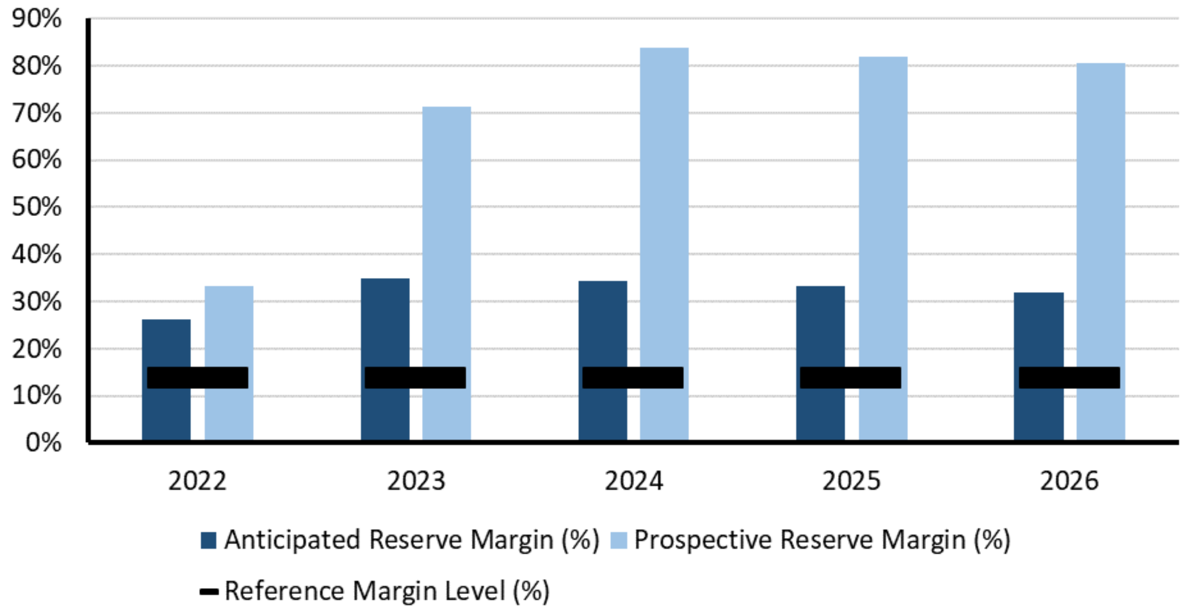


Figure 8: Texas RE-ERCOT Five-Year Projected Reserves (ARM and PRM)

Recommendation for Key Finding 1

Regulators and policymakers should review the scope of their resource adequacy requirements to ensure that they address risks of both energy and capacity shortfalls and consider both peak and non-peak demand hours. They should also consider limitations from neighboring systems during wide-area, long-duration extreme weather events and potential generator fuel supply limitations.

Key Finding 2 (Energy Risks)

Since the publication of the ERO's probabilistic assessment in 2020, additional analysis indicates that risk of load loss and energy shortfalls persist in the Western Interconnection and MISO areas.

Key Points

- ProbAs give detailed resource adequacy metrics that can help identify the risk of energy shortfall over an entire year or other periods.
- The 2020 ProbA identified elevated load-loss risk in MISO, MRO-SaskPower, and the WECC-NWPP areas as well as high risk in WECC-CA/MX for 2022 and beyond. While conditions in MRO-SaskPower have improved, concerns remain in the other areas.
- The risk of unserved energy and LOLH in MISO in the near-term horizon has increased due to the declining resources since the 2020 ProbA. Reserve margins could fall below the Reference Margin Levels beginning in 2024 (see **Key Finding 1 (Reserve Margins)**. This indicates that, without additional resources from the interconnection planning queue or other sources, the projected resources in MISO after 2023 are not sufficient to meet a 1-day-in-10-year loss of load criteria under current forecasts.
- The two largest U.S. assessment areas in the Western Interconnection—California/Mexico (WECC-CA/MX) and the WECC-NWPP-US & RMRG areas—have the risk of energy shortfalls for 2022 and beyond. In updated probabilistic studies of demand and resource scenarios for 2022, WECC-CA/MX shows 10 hours that fall below the 99.98% reliability threshold for potential loss of load risk given the variability of demand and resource availability after imports while the WECC-NWPP-US & RMRG areas show 23 hours. Higher load-loss metrics are seen in the 2024 study year for all U.S. areas of the Western Interconnection.

2020 Probabilistic Assessment Results

The *2020 LTRA* includes the ERO's biennial ProbA, which provides insights into the ability of the future resource mix to meet the projected demand at all times.[24] While deterministic PRM assessment findings can indicate sufficient resource capacity is planned to be available to meet peak demand for most areas, probabilistic assessments (e.g., the 2020 ProbA) examine detailed demand and resource profiles to produce metrics that identify risk of energy shortfall over an entire year or other periods. Observations from the 2020 ProbA, which analyzed years 2022 and 2024, include the following:

- Nearly all parts of the Western Interconnection, with the exception of WECC-NWPP-AB, showed heightened loss of load risk in the study years. In California and the U.S. Northwest, the observed risk is highest during summer months in early evening—after demand has peaked and while output from solar PV resources has diminished.
- Texas RE-ERCOT showed the greatest risk at peak demand hours in summer; however, declining thermal generation is causing operating reserves to fall during a range of hours around the daily peak demand and during new shortfall risk periods that emerge in shoulder seasons when thermal generators typically perform maintenance.
- In MISO, the loss of load hours occurring in study years were concentrated during summer peak periods and correlated to times when load and forced outages are highest. A small but growing risk of unserved energy was observed during times when demand is not at peak levels (e.g., during spring or fall seasons when planned generator outages for maintenance could coincide with unseasonably high load in shoulder months). Additionally, the 2020 probabilistic assessment identified the emergence of risk.

Areas with higher penetration of VERs, like wind and solar, are more susceptible to the emergence of energy risks that may not be confined to the time of peak demand. Operators can face energy emergencies if energy-limited resource production falls short of demand on the system, and flexible energy-assured generation, imports, and DR are not sufficient to make up for the shortfall.

Subsequent to the *2020 LTRA* publication, the 2020 *Probabilistic Assessment Regional Risk Scenario Sensitivity Case* was published in June 2021.[25] The summary of the findings are as follows:

> Sensitivity results were varied across the study areas and dependent on their underlying assumptions. In some assessment areas (i.e., MRO-Manitoba Hydro, MRO-SaskPower, PJM, and all assessment areas of WECC-NPCC), the study demonstrated that the risks were not significant, did not impact the probabilistic indices, and/or could be mitigated by using preventive planning and operating measures. Other assessment areas noted potential risks if the chosen scenario was to materialize under the sensitivity assumptions. SPP determined LOLH and EUE increases in their scenario mostly occur on or around the peak hour. SERC also noted low to moderate increases in their loss of load indices from the Base Case associated with maintenance outages, noting an emphasis and need to adequately plan outage windows accordingly. WECC found that, in many assessment areas across the Western Interconnection, the advanced retirement of coal units either dramatically increases or negligibly increases the LOLH or EUE. Results were also dependent on the

[24] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf

[25] See *NERC 2020 Probabilistic Assessment Risk Scenarios Report*: https://www.nerc.com/comm/RSTC/PAWG/2020%20ProbA%20Regional%20Risk%20Scenarios%20Report_final_approved.pdf

amount of available external assistance between assessment areas and the penetration of coal resources in their respective portfolios. MISO conducted a sensitivity on increased DR to replace conventional generation and indicated an increase in the EUE and LOLH metrics, showing that limited call DR is not as effective as conventional resources on a MW to MW basis.

In addition, NERC obtained updates to the findings of the 2020 ProbA from each assessment area if significant changes had occurred. The updates included reviews of system conditions to determine the validity of the 2020 ProbA and references to other probabilistic analysis pertinent to the assessment area as well as performance of additional probabilistic analysis with updated data and assumptions.

WECC's Update

WECC provided a full probabilistic analysis update of their 2020 ProbA analysis, and their findings are presented in this section of the NERC *2021 LTRA*.

Since the development of the 2020 ProbA, a few modeling methodologies and assumptions have been revisited for the development of this *2021 LTRA*. Due to the COVID-19 pandemic and its impact on behavior and energy usage patterns, 2020 demand was not typical. To compensate for this, demand modeling for the *2021 LTRA* utilized a 2019–2020 hybrid shape, and the location of a generation resource was revised. The significant results for the WECC assessment areas are summarized in **Table 2**. The results shown are potential load loss for the less likely system conditions of higher demand levels and lower resource capacity levels than 50/50 conditions represented in the distributions of the uncertainties of load and resources.

Table 2: 2021 Probabilistic Summary Results in WECC			
CA/MX			
Annual Probabilistic Indices			Trend Since 2020 ProbA
	2022	2024	
EUE (MWh)	5,864	75,121	Decreasing
LOLH (hours/year)	10	32	Decreasing
NWPP-US & RMRG			
Annual Probabilistic Indices			Trend Since 2020 ProbA
	2022	2024	
EUE (MWh)	5,756	35,813	Increasing
LOLH (hours/year)	23	46	Increasing
SRSG			
Annual Probabilistic Indices			Trend Since 2020 ProbA
	2022	2024	
EUE (MWh)	0	842	Increasing
LOLH (hours/year)	0	17	Increasing

The color shading in **Table 2** is used to identify relative risk for loss of load hours. **Green** indicates that the risk is low (calculated LOLH is less than 0.1 hours per study year). When calculated LOLH exceeds 2.4 hours per year, the study indicates that the area may have a loss of load expectation that is greater than 1-day-in-10 years, a criteria used in many areas to determine resource adequacy (see **Table 11**). Instances where ProbA results are greater than 2.4 hours per year are in **red**. These color conventions were also used in the *2020 LTRA*, where the 2020 ProbA was published.

WECC-CA/MX

The California/Mexico assessment area of the Western Interconnection has experienced a shift in the expected peak hour demand. In previous LTRAs, the peak hour for demand was expected to occur at hour beginning 3:00 p.m. local time. This year's LTRA represents the peak hour for demand as being one hour later beginning at 4:00 p.m. local time. This is significant as it has an impact on the expected solar availability when viewing 3:00 p.m. vs. 4:00 p.m. local times.

Solar Availability

Table 3 shows the expected solar output by hour in the WECC-CA/MX area as a percentage of the peak output. As can be seen in Table 3, the expected availability of solar resources is **74%** for hour beginning **3:00 p.m.** local time as was highlighted in last year's LTRA. However, with the peak demand hour shifting to hour beginning **4:00 p.m.** local time, the LTRA results are highlighting an hour where only **56%** of the solar capacity is expected to generate. It is not that the portfolio has significantly changed from one LTRA to the next, it is only a matter of the hour being shown in the LTRA that has shifted.

Table 3: Expected Output of Solar Resources by Hour in CA/MX Area

Hour Beginning	Solar Availability	Hour Beginning	Solar Availability
12:00–5:00 a.m.	0%	1:00 p.m.	85%
6:00 a.m.	1%	2:00 p.m.	81%
7:00 a.m.	18%	**3:00 p.m.**	**74%**
8:00 a.m.	47%	**4:00 p.m.**	**56%**
9:00 a.m.	68%	5:00 p.m.	29%
10:00 a.m.	77%	6:00 p.m.	7%
11:00 a.m.	85%	7:00–11:00 p.m.	0%
12:00 p.m.	86%		

Given the shift in the peak demand hour, the WECC-CA/MX area is significantly short of the calculated RML needed to maintain a 1-day-in-10-year level of reliability for the hour reflected in this assessment. With just existing resources, the area falls sort of the RML for the peak hour beginning in the summer of 2024. Given how this shift in peak demand hours highlights how important it is to represent all hours in this assessment, WECC will continue to use their probabilistic assessment results to work with the areas to highlight all risks as more mitigation will be needed other than just hour beginning at 4:00 p.m. local time.

WECC-NWPP-US & RMRG

Reserve margins for WECC-NWPP-US & RMRG are 21.49% for 2022 and 22.83% for 2024, but there are 23 hours in 2022 that fall below WECC's 99.98% reliability assessment threshold that are due in part to the changing resource mix; in 2024, the potential of shortfall rises to 46 hours. A large amount of unserved energy is associated with these hours of risk.

WECC-SRSG

Reserve margins for the WECC-SRSG area are 31.03% for 2022 and 27.09% for 2024, but there are levels of LOLH in 2024 of 17 hours due in part to the changing resource mix. The potential unserved energy in the area during these hours rises to over 800 MWh in 2024.

MISO Update

The risk of unserved energy and LOLH in MISO in the near-term horizon has increased due to the declining resources since the 2020 ProbA. As discussed in Key Finding 1, ARMs are projected to be below the Reference Margin Levels beginning in 2024. This indicates that, without additional resources from Tier 2 or other sources, the anticipated resources in MISO after this year are not sufficient to meet a 1-day-in-10-year loss of load criteria. Expected loss of load above this criteria is higher than the results the 2020 ProbA indicated (0.2 hours per year in 2022); however, comparison with LOLH is not precise. Additional ProbA measures of energy risks, such as EUE in non-peak months, would also increase with less generation if studies were re-run today.

As the MISO fleet continues to evolve, ongoing comprehensive analysis is underway and will continue in order to detail risks and inform change in MISO's planning, markets, and operations processes. Projects to develop solar and wind generation continue to grow in MISO's interconnection planning queue. As noted in later sections of this report, MISO is a leading region for capacity in planning for both solar and wind, and MISO planners are applying lessons learned from this resource shift. MISO is leveraging its resource adequacy construct and pricing enhancements as well as the forums where discussions are already underway on transmission planning in order to ensure needed changes are identified and enhancements made as demand for and production of electricity continues to develop.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss of Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve). LOLH should be evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study horizons. LOLH does not inform of the magnitude or the frequency of loss of load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., behind the meter (BTM) solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss of load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss of load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[26] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

The traditional methods of assessing resource adequacy focused at peak load times may not accurately or fully reflect the ability of the new resource mix to supply energy and reserves for all hours. Energy limitations can exist, requiring probabilistic analysis methods to identify risks to reliability that result from shortfalls in the conversion of capacity to energy (energy adequacy). The new resource mix includes natural-gas-fired generation; unprecedented proportions of non-synchronous resources, including renewables and battery storage; DR; smart- and micro-grids; and other emerging technologies. Collectively, the new resources are more susceptible to energy sufficiency uncertainty.

Recommendations for Key Finding 2

Regulators and policymakers in risk areas should coordinate with electric industry planning and operating entities to develop policies that prioritize reliability, including those that would promote the development and use of flexible resources, and maintain a sustainable and diverse generation mix.

Industry planners should pay close attention to the ramping and load-following requirements for their system as VERs increase, and they should commit flexible resources to meet the system reliability needs.

The ERO and industry should develop processes and techniques to assess the adequacy of energy supplies and ensure that the changing resource mix can meet operational needs. Capacity-based resource adequacy measures and criteria (e.g., PRMs and RMLs) do not ensure that sufficient amounts of energy will be available for a variety of potential weather and environmental conditions. Energy metrics, such as EUE levels, are also an important part of assessing BPS reliability. The ERO and industry should develop tools to incorporate energy considerations into planning and operational assessments. They should also explore desired energy performance levels and evaluate NERC Reliability Standards for enhancements necessary to ensure energy adequacy in planning and operating time horizons.

[26] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

Key Finding 3 (Extreme Weather Risks)

Parts of North America are exposed to energy shortfall risks in the near-term assessment period from wide-area and long duration extreme weather events like the 2020/2021 western heat wave and winter storm Uri in 2021.

Key Points

- Extreme weather can cause challenging grid operating conditions by both diminishing the supply of electricity and driving actual demand above forecasts. Near-term demand forecasts, resource projections, and other trends suggest that even parts of North America that are considered resource adequate at the traditional peak hour evaluation are becoming increasingly exposed to energy shortfall risks in extreme weather events.
- The increasing volatility and uncertainty of electricity demand makes accurate load forecasting a challenge, increasing the risk that BAs may be unprepared for the peak demands that can accompany extreme weather events. In extreme temperatures, areas with relatively high seasonal LFU and low PRM are at risk of capacity shortfall: WECC-CA/MX and NWPP-US & RMRG areas near-term summer projections fall into this category.
- Areas that rely on VERs or imports to meet peak or other high-risk periods face greater risk in wide-area, long-duration weather events and when weather-dependent generation is impacted by abnormal atmospheric conditions, such as smoke or wind drought. Where extended drought increases the risk of wildfires, transmission lines can be impacted, curtailing electricity transfers that are needed to serve demand. Texas, California, and the U.S. Northwest currently or in the near term will depend on a combination of transfers, wind, and solar generation to meet projected peak demand. MISO and the U.S. Southwest are approaching similar thresholds in near-term projections. In the event that one or more of these resources fall short of forecast at peak conditions, other resources must make up the gap, or load will need to be shed.
- Reliable operation of thermal generating units and fuel assurance is critically important, especially during extreme weather events.

Extreme weather that diminishes the supply of electricity or pushes demand to levels well above normal is a growing resource adequacy concern. Recent wide-area hot and cold weather events, persistent drought, and wildfires have affected the ability to reliably serve demand in some areas during these abnormal conditions. These events can challenge grid operators by exceeding normal peak electricity demand forecasts, diminishing power output from energy-limited VERs, limiting imports available to high-demand areas, and forcing generators off-line in harsh conditions. Several trends and factors suggest that even the parts of North America that are considered resource adequate are becoming increasingly exposed to energy shortfall risks in extreme weather.

Load Forecast Uncertainty

PRMs, probabilistic studies, and various resource adequacy and operational tools depend on forward-looking projections of demand that are based on historical data. Though demand forecasts adapt to changes over time and account for a degree of uncertainty, abrupt or large changes in climatology or the electrical system can lead to a case where a forecast based on historical data is a poor representation of a future reality. Aside from weather patterns, load in many parts of North America is growing in complexity—this could be due to increasing levels of variable-output solar PV DERs, electrification of heating and transportation sectors, and pandemic-related behavior changes. It can be more challenging to forecast demand in both long-term and operating time horizons as a result. In real terms, this can mean that extreme heat and cold weather can drive demand significantly above the normal (50/50) forecasted demand level. As an example, **Figure 9** shows the forecasted and actual winter peak demand in Texas RE-ERCOT over the last 10 years.

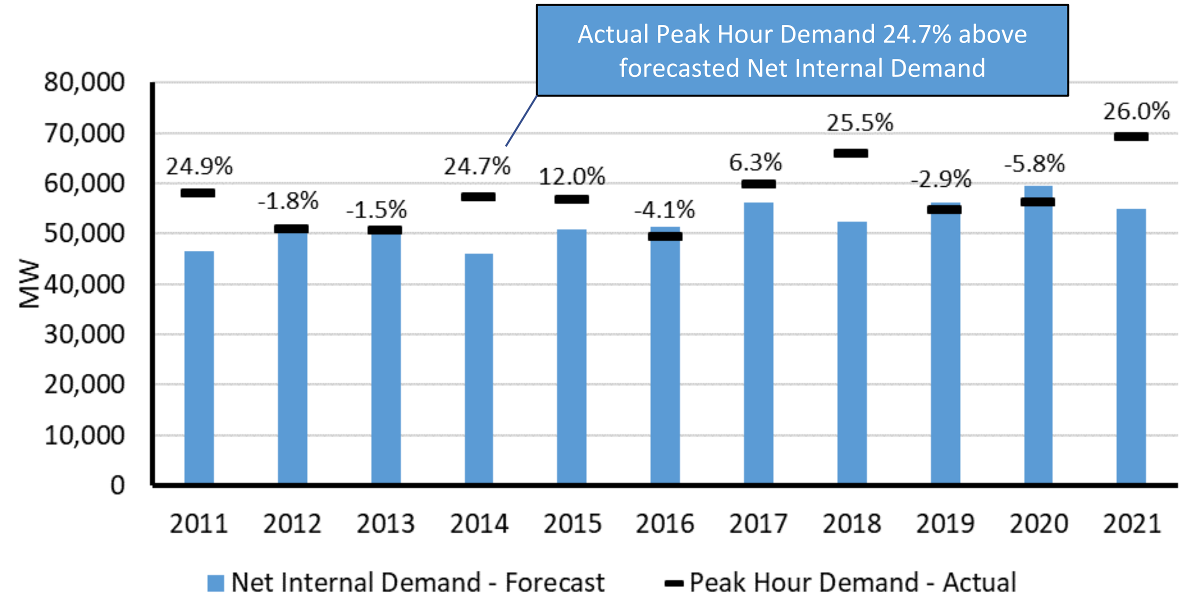


Figure 9: Actual and Forecasted Winter Peak Demand in ERCOT, Last 10 Years

Seasonal on-peak LFU accounts for not only the unpredictability in what the actual highest summer temperature or lowest winter temperature will be as well as the responsiveness of demand at this temperature. Figure 10 provides an example for a normally-distributed LFU probability distribution. Expressed as a percentage, it represents how much higher (or lower) the forecasted peak demand in an extreme temperature scenario is expected to deviate from the peak demand in an average year. The impact of 4% addition to 50/50 forecasted demand is assessed as part of the probabilistic determination of the Reference Margin Levels at an occurrence probability of 8%.

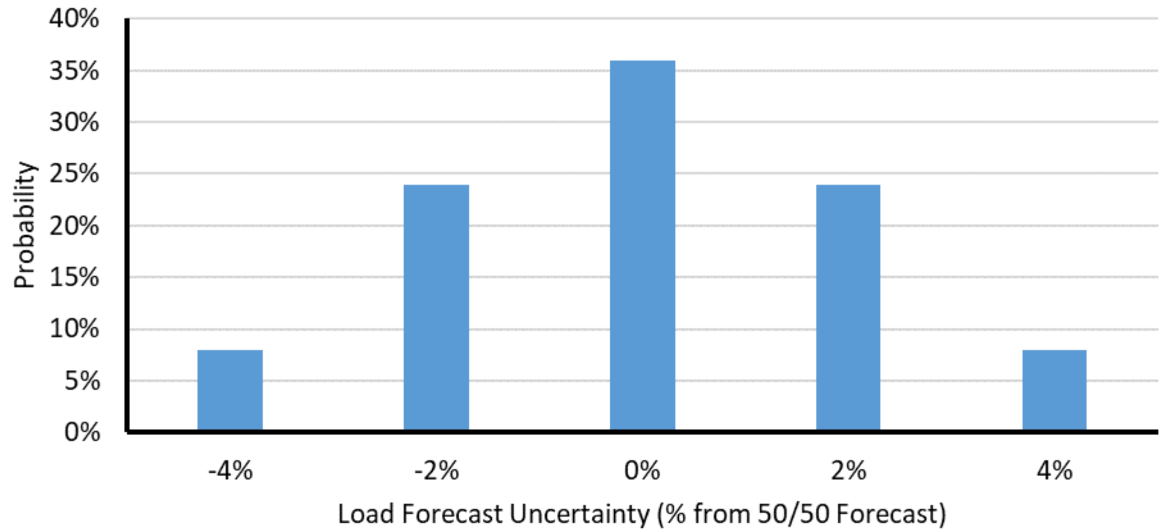


Figure 10: Example of Normally-Distributed Load Forecast Error

Shown in Table 4 are the assessment areas with the highest projected LFU variation for extreme temperature scenarios (mostly at the 90/10 occurrence probability) in 2022 and 2024 as reported to NERC in the 2020 ProbA. Comparing Texas RE-ERCOT's actual peak demand in 2021 (26% above forecasted demand) to their 90/10 LFU in Table 4 (13.5% above forecasted demand) indicates the extreme severity of the 2021 weather event on load.

Table 4: Areas with Highest Load Forecast Uncertainty

Assessment Area	2022		2024	
	Winter	Summer	Winter	Summer
WECC-CA/MX	4.9%	15.7%	4.9%	15.6%
Texas RE-ERCOT	13.5%	2.2%	12.5%	2.1%
SERC-Southeast	12.2%	12.2%	12.2%	12.2%
NPCC-Ontario[27]	11.4%	11.4%	11.4%	11.4%
NPCC-New England	10.9%	10.9%	10.9%	10.9%
WECC-SRSG	8.5%	10.8%	8.5%	8.3%
WECC-NWPP-US & RMRG	7.8%	10.5%	5.2%	8.6%
NPCC-Québec	9.1%	10.5%	9.2%	8.8%
SERC-Central	9.5%	9.5%	9.5%	9.5%
NPCC-Maritimes	9.2%	9.2%	9.2%	9.2%
Average of All Assessment Areas	7.4%	7.6%	7.1%	7.4%

Reliance on Imports and Transmission for Peak Demand or Other Risk Hours

When extreme temperatures extend over a wide area for a long duration, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Additionally, transmission networks can become stressed when events, such as wildfires or wide-area heatwaves, cause network congestion. Some assessment areas expect imports from other areas to be available to meet periods of peak demand or other risk periods and have contracted for firm transfer commitments. Firm resource transactions are included in the anticipated and PRMs for all assessment areas. In the unlikely event that multiple assessment areas are experiencing energy emergencies, as could occur in a wide-area heatwave or winter storm, 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. Figure 11 shows the portion of peak demand that is being served by imports in 2022 and 2024 along with VERs discussed in the following section in areas where transfers and VER make a significant contribution (10% or more of anticipated resources).

High Level of Variable Energy Resources to Meet Peak Demand

VERs include wind, solar, and run-of-river hydroelectric plants for which electric output can change according to the primary driver (i.e., moving air, sunlight, moving water), resulting in plant output

[27] Ontario IESO bases their extreme demand scenarios on the peak demand in a 31-year period, not necessarily the 90/10 demand forecast.

fluctuations on all time scales. Planners and operators must address and prepare for the uncertainty associated with these resources because the magnitude and timing of variable generation output is less predictable than for conventional generation. Some wide-area weather events can include not only extreme temperatures but also conditions that are unfavorable for VERs: extreme or persistent droughts that lead to poor hydrologic conditions or stalled high-pressure systems in the atmosphere that causes uncharacteristic changes in wind patterns. Atmospheric conditions, such as smoke and cloud cover, can limit output from solar PV resources. **Figure 11** projections include the expected on-peak capacity contribution of anticipated resources. The percentages located beside each bar indicate the extent to which WECC-CA/MX, WECC-NWPP-US & RMRG, and Texas RE-ERCOT rely on transfers and variable resources to meet peak demand. Other assessment areas are becoming increasingly reliant on solar and wind resources and transfers to meet peak demand. In the event that solar and wind output are below expectations, areas may need to rely on additional and/or external resources to cover the shortfall.

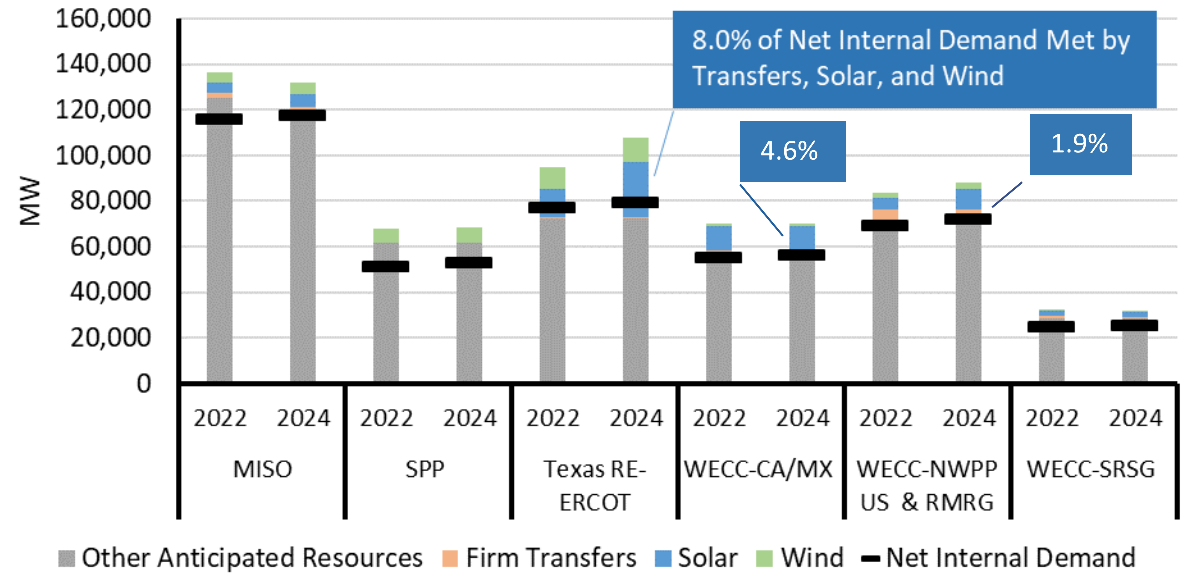


Figure 11: Solar, Wind, and Transfer Contributions to Peak Demand
(areas with 10% or more of anticipated resources coming from solar, wind, and transfers)

Thermal Generation Fleet Exposure to Fuel Supply Risks or Weather-Related Outages
Reliable operation of thermal generating units is critically important during extreme weather events to meet demand peaks in above-normal conditions, provide essential reliability services (ERS), and support system operators with flexible resources when VER output is diminished. Higher forced outages of the thermal generation fleet has been a common issue when extreme weather events have led to energy emergencies. Inadequate winterization of thermal and wind generation in parts of MISO, SPP, and Texas-RE ERCOT that do not typically experience extreme cold temperatures remains a significant risk in winter reliability until new NERC winterization requirements highlighted in the *February 2021 Cold Weather Outages Report* are effective.

Across North America, the thermal generation fleet has transitioned from a diverse mix of fuel types to one that is increasingly dominated by natural-gas-fired generation. While all generator types can be expected to have increased forced outages in extreme weather, natural gas as a generator fuel is not typically stored on-site, resulting in greater risk of fuel supply disruption.

Natural gas supply disruptions in infrastructure-limited areas of New England, California, and the U.S. Southwest have the potential to affect BPS reliability, particularly in winter. In NPCC-New England, the capacity of natural gas transportation infrastructure can be constrained when cold temperatures cause peak demand for both electricity generation and consumer space heating needs. Generators that lack firm natural gas delivery can have their supplies curtailed when the demand for natural gas peaks. As a result, the area relies on fuel oil and imported LNG to meet winter peak loads.[28] New England independent system operator (ISO) planners' estimate that as much as 16% of its winter generating capacity could be at risk from natural gas fuel supply limitations in extreme winter conditions. Southern California and the U.S. Southwest have limited natural gas storage and lack redundancy in supply infrastructure. As a result, electric generators face the risk of fuel supply curtailment or disruption from extreme winter weather events.[29]

[28] ISO-NE Winter 2017/2018 Recap: Historic cold snap reinforces findings in Operational Fuel-Security Analysis: https://isonewswire.com/2018/04/25/winter-2017-2018-recap-historic-cold-snap-reinforces-findings-in-operational-fuel-security-analysis/
[29] Western Interconnection Gas – Electric Interface Study: https://www.wecc.org/Reliability/Western%20Interconnection%20Gas%20Electric%20Interface%20Study%20Public%20Report.pdf

Recommendations for Key Finding 3

In addition to the recommendations found elsewhere in the report, the following will enhance extreme weather reliability:[30]

- The ERO and industry should strengthen their winterization and cold weather preparedness and coordination and enhance Reliability Standards to reduce the risks to electric reliability from extreme winter weather conditions. Regulators and policymakers should adopt policies that promote hardening electric generation and transmission facilities as well as fuel supplies to operate in specified temperatures for their areas.
- Generator Owners, Generation Operators, and BAs should increase coordination on seasonal operating plans. BAs must be aware of the performance expectations of all generators at forecast ambient conditions, and the BAs' plans should only depend upon generators that have a reasonable expectation of performing during forecast conditions.

[30] For specific details on recommendations for cold weather grid operations, see the findings and recommendations of the Joint FERC/NERC/Regional Entity Inquiry into the February 2021 cold weather event: https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

Key Finding 4 (Frequency Response)

Frequency response is expected to remain adequate through 2023.

Key Points

- Despite increasing amounts of asynchronous resources and less inertia from retirement of rotating generation, each of the four Interconnections expect to have adequate and diverse sources of frequency response and all have a low likelihood of activating UFLS schemes.
- Maintaining Interconnection frequency within acceptable boundaries following the sudden loss of generation or load can be accomplished by using inverter control functions, including energy storage and load-shedding relays. This is generally known as FFR. The application of FFR is expected to continue and support frequency when synchronous inertia is insufficient.
- Future changes to the resource mix will continue to impact the level of inertia.

Frequency Response and Inertia Measures

Trends in the frequency measures can be analyzed by using historical data and projected into the future by using reasonable planning assumptions and models. The NERC RSTC and its predecessors, the PC and Operating Committee (OC), jointly created the Essential Reliability Services Task Force in 2014 to consider reliability issues that may result from the changing generation resource mix. In 2015, the ERSTF proposed measures for ERSs pertaining to the examination and potential ongoing monitoring in order to identify trends. The ERSTF was converted into the Essential Reliability Services Working Group in 2016 and charged with identifying, evaluating, and developing sufficiency guidelines for each quantifiable measure.

The holistic frequency measure, called Measure 4 in Essential Reliability Services Working Group reports, tracks phases of frequency performance for actual disturbance events in each Interconnection, such as initial frequency rate of change and timing of the arresting and recovery phases. Other measures look at components of this coordinated frequency response, such as the amount of synchronous inertial response (Measure 1) and the initial rate of change in frequency following the largest contingency event (rate of change of frequency, Measure 2). These measures are further described in **Table 5**.

Table 5: Measures of Frequency Response

Measure	What it Measures	Summary Assessment Findings
Synchronous Inertial Response (Measure 1)	The minimum inertial response amount (total stored kinetic energy) projected in each Interconnection	Despite the retirement of synchronous generation over the past eight years, there appears to be more than sufficient inertia within all Interconnections. ERCOT's use of load response to respond to frequency disruptions is effective in supporting low-inertia conditions.
Rate of Change of Frequency (Measure 2)	The calculated rate of frequency decline within the first 0.5 seconds following the largest credible contingency	No negative trends identified. Texas RE-ERCOT studies show that load response is extremely effective in arresting frequency due to its ability to perform very quickly.
Frequency Response Performance (Measure 4)	Simulated dynamic behavior of an Interconnection's response to the largest credible contingency	Simulations in both the Eastern and Western Interconnection show sufficient frequency response in future planning cases.

The current resource loss protection criteria (RLPC) for each Interconnection is provided in **Table 6**. The defined values correspond to selecting the RLPC used for BAL-003-2 requirements and Interconnection frequency response obligations. This updated version of the standard came into effect December 01, 2020, and one of the major changes is the method of selecting the RLPC. If operating restrictions would limit the RLPC, then that will be accounted for as part of the case creation and contingency definition. For example, Hydro Québec limits generation dispatch for low inertia conditions such that 1,700 MW RLPC cannot occur; this mitigates a potential severe contingency where inertial conditions are of concern.[31]

[31] The RLPC values in **Table 6** are in effect as of November 2021. Revised RLPC values are being determined at NERC per Reliability *Standard BAL-003-2 – Frequency Response and Frequency Bias Setting*. Although revised RLPC values are expected, NERC does not anticipate that the changes would alter the frequency response conclusions in this *2021 LTRA*.

Table 6: RLPC and UFLS Tripping Set-Points by Interconnection			
Eastern Interconnection	Western Interconnection	Texas Interconnection	Québec Interconnection
3,852 MW	2,905 MW	2,805 MW	1,700 MW
59.5 Hz	59.5 Hz	59.3 Hz	58.5 Hz

Trends and Projected Interconnection Performance
A summary of each Interconnection's results for NERC's assessment is included in **Table 7**. Despite increasing amounts of asynchronous resources and decreasing inertia from generation, each of the four Interconnections expect to have adequate and diverse sources of frequency response, so they all have a low likelihood of activating UFLS schemes. These results were confirmed by dynamic studies performed for the Eastern, Western, and Québec Interconnections and implemented operational procedures for Texas Interconnection.

In February of 2018, FERC Order No. 842 was issued and mandates that all new generating facilities in the United States maintain the capability of providing primary frequency response. While FERC Order No. 842 does not require certain performance of providing frequency response in real-time, it does provide clear direction and assurances that all generation resources connected to the BPS have the capability of providing it.

Table 7: Summary of the Results of NERC Frequency Response Sufficiency Assessment				
Interconnection	Highest Non-Synchronous Penetration at Minimum Inertia	Number of Critical Inertia Conditions Reached?	Lowest Frequency Nadir Observed in Planning Studies	Likelihood of Credible Disturbance Resulting in UFLS Activation
Eastern Interconnection	9.5%	0	59.82 Hz	Low
Western Interconnection	10%	0	59.70 Hz	Low
Texas Interconnection	54%	0	N/A	Low[32]
Québec Interconnection	13%	0	N/A	Low

As the resource mix continues to evolve, so is the resulting Interconnection inertia. NERC and the Resources Subcommittee are working with the Interconnections to monitor their respective annual minimum synchronous inertial response for trending. Due to their smaller size, the Texas and Québec Interconnections experience lower system inertia compared to the Eastern and Western Interconnections. Currently, wind amounts to more than 17% of installed generation capacity in the Texas Interconnection and has served as much as 50% of system load during certain periods. In Québec, hydro accounts for over 95% of the generation; hydro generally has lower inertia compared to synchronous generation of the same size (e.g., coal and combined-cycle units). As a result, ERCOT and Hydro-Québec have both established unique methods to ensure sufficient frequency performance.

Recommendations for Key Finding 4

NERC should continue working with the Eastern, Western, and Texas Interconnection study groups to assess forward-looking Interconnection frequency response. The analysis should continue to evolve and reflect low-inertia conditions that may be anticipated by the current and future generation resource mix.

[32] ERCOT procures responsive reserve service to protect from involuntary under frequency load shed after loss of two largest generating units at a single plant (2,805 MW). In March 2020, a new subproduct of responsive reserve service was introduced, FFR, which is triggered at 59.85 Hz within 0.25 seconds. Up to 450 MW of FFR can be procured as a part of responsive reserve service. This product is still going through implementation stages due to required changes to ERCOT systems.

Key Finding 5 (Resource Mix Changes)

Variable energy resources continue to grow, and thermal resource capacity declines in most areas throughout the assessment period. As a result, increased attention on planning and operating a more complex resource mix is required.

Key Points

- Projects to develop solar and wind generation for the BPS continue to grow in the Interconnection's planning queues. Since the *2020 LTRA*, the nameplate capacity of solar projects in all stages of development has increased from 390 GW to 504 GW for the next 10 years. Wind projects now total 360 GW of nameplate capacity over the next 10 years, up from 250 GW since the *2020 LTRA*.
- Texas RE-ERCOT, PJM, and MISO have the most solar capacity in planning. MISO, NPCC-New England, PJM, SPP, and Texas RE-ERCOT have the most wind capacity in planning.
- Existing battery resources and projects in the interconnection queues at various stages of development through 2024 currently total over 113 GW—a substantial increase from the 47 GW reported for the same period in the *2020 LTRA*.
- DER growth continues with cumulative solar PV DER expected to reach over 60 GW by the end of this 10-year assessment period. A total of 15 of the 20 assessment areas expect to double their total solar DER footprint by 2031. This growth highlights the need for the ERO as well as planners and operators in growth areas to take actions that ensure planning processes and operating measures are in place to ensure reliability.
- In many areas, VERs are increasingly important to meet electricity demand. Operators must have sufficient flexible resources, including adequate dispatchable, fuel-assured, and weatherized generation, at their disposal in areas with high levels of variable generation to avoid shortfalls when VER output is insufficient to meet demand.[33]
- IBRs, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. Maintaining a reliable system as the penetration of IBRs increases requires planners and operators to be cognizant of potential disturbance-related performance issues.

Variable Energy Resources

VERs include wind, solar, and run-of-river hydroelectric plants for which electric output can change according to the primary driver (i.e., moving air, sunlight, moving water), resulting in plant output fluctuations on all time scales. Planners and operators must address and prepare for the uncertainty associated with these resources because the magnitude and timing of variable generation output is less predictable than for conventional generation.

Capacity Additions

Wind, solar, and natural-gas-fired generation are the overwhelmingly predominant generation types in the planning horizon for addition to the BPS. The generation resources for all fuel types are shown in **Figure 12** (for Tier 1 planning) and in **Figure 13** (for Tier 1 and 2 planning) unless they are too small to be visible.

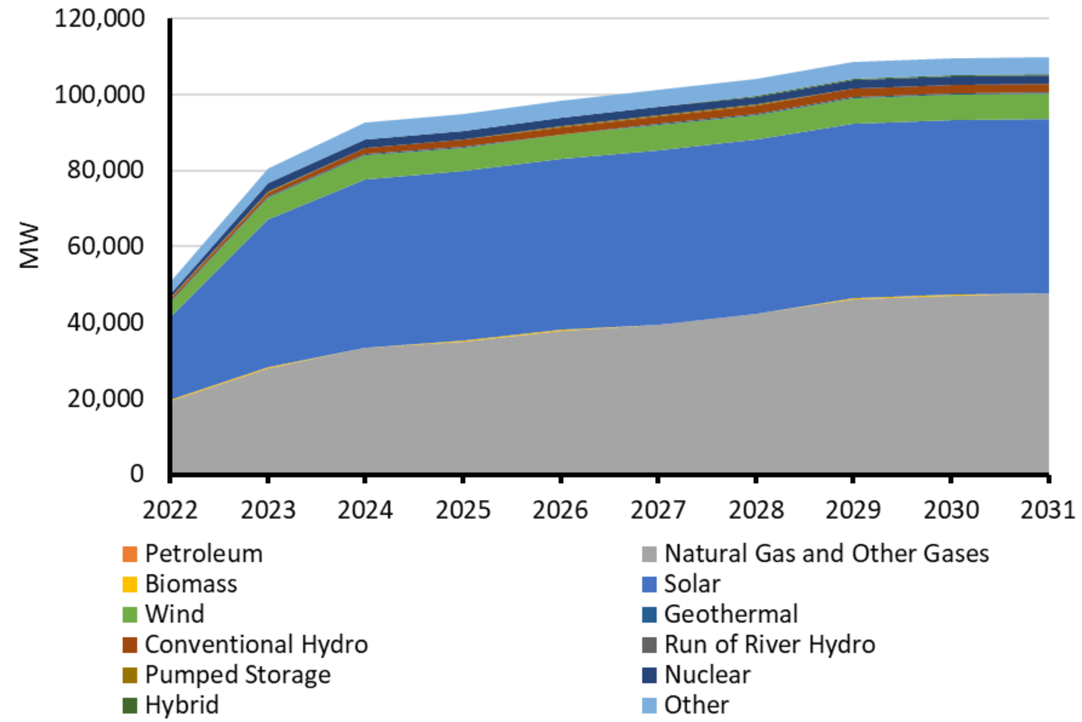


Figure 12: Tier 1 Planned Resources Projected Through 2031

[33] Flexible resources refer to dispatchable conventional as well as dispatchable variable resources, energy storage devices, and dispatchable loads.

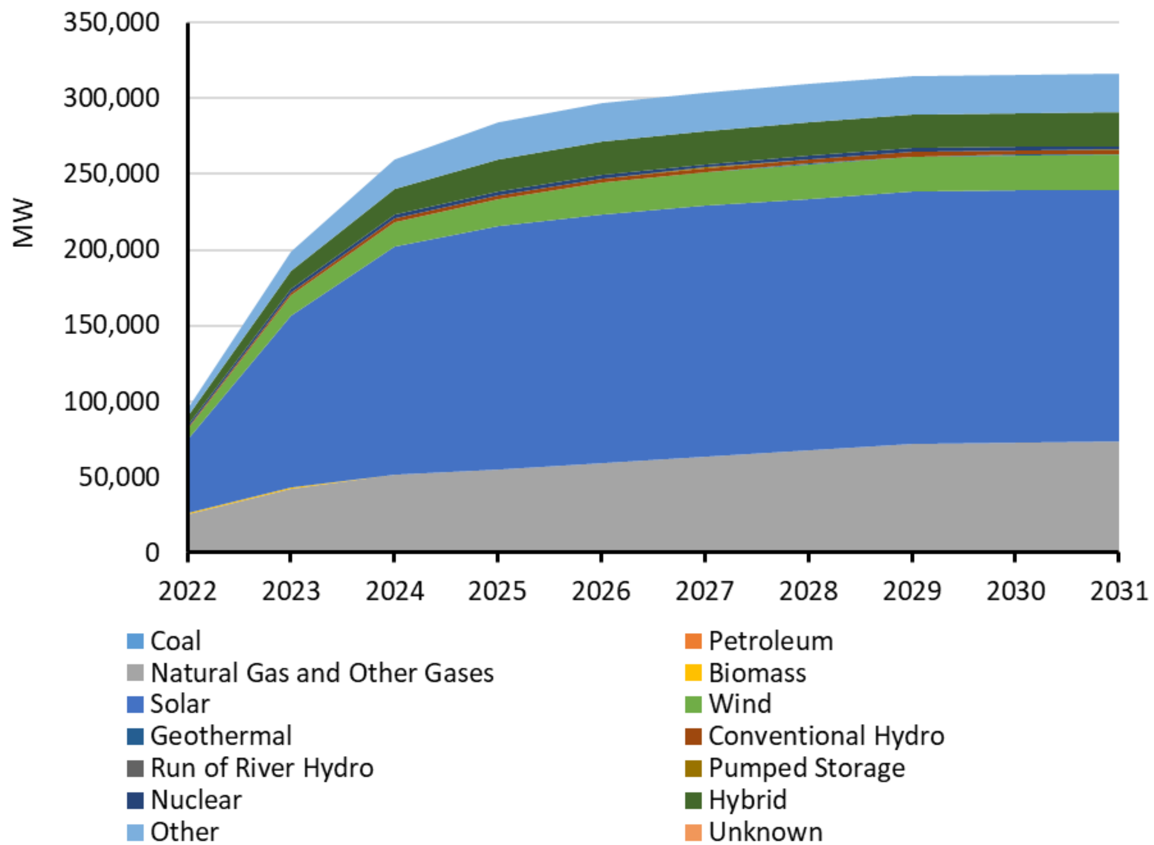


Figure 13: Tier 1 and 2 Planned Resources Projected Through 2031

NERC Capacity Supply Categories

Future capacity additions are reported in three categories:

Tier 1: Planned capacity that meets at least one of the following requirements is included as anticipated resources:

- Construction complete (not in commercial operation)
- Under construction
- Signed/approved Interconnection service agreement
- Signed/approved power purchase agreement
- Signed/approved Interconnection construction service agreement
- Signed/approved wholesale market participant agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to vertically integrated entities)

Tier 2: Planned capacity that meets at least one of the following requirements is included as prospective resources:

- Signed/approved completion of a feasibility study
- Signed/approved completion of a system impact study
- Signed/approved completion of a facilities study
- Requested Interconnection service agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to Regional Transmission Organizations (RTO)/independent system operators (ISO))

Tier 3: Tier 3 is other planned capacity that does not meet any of the above requirements.

Significant solar and wind capacity additions are expected over the next 10 years. **Table 8** identifies solar and wind installed capacity additions by assessment area. From an installed capacity perspective, over 504 GW of new solar and wind are in development through 2031, including Tier 1, 2, and 3 resources. Of all generation resources, future solar capacity is expected to be the largest contributor at 289 GW when considering Tier 1 and 2 resources and 360 GW when considering Tier 3 resources. Wind capacity is expected to increase by 85% by 2031 when considering Tier 1 and Tier 2 resources.

Table 8: Solar and Wind Nameplate Capacity, Existing and Planned Additions through 2031										
Assessment Area	Nameplate MW of Solar					Nameplate MW of Wind				
	Existing	Tier 1	Tier 2	Tier 3	Total	Existing	Tier 1	Tier 2	Tier 3	Total
MISO	728	10,989	53,756	4,907	**70,379**	22,854	5,593	14,649	730	**43,825**
MRO-Manitoba	-	-	-	-	**-**	259	-	-	-	**259**
MRO-SaskPower	2	10	10	57	**80**	242	385	200	100	**927**
NPCC-Maritimes	2	51	54	-	**107**	1,181	20	30	400	**1,631**
NPCC-New England	1,828	498	922	2,672	**5,920**	1,486	1,675	9,854	8,176	**21,191**
NPCC-New York	32	103	1,552	4,827	**6,513**	1,818	789	991	5,580	**9,177**
NPCC-Ontario	478	-	-	-	**478**	4,786	160	-	-	**4,946**
NPCC-Québec	10	-	-	-	**10**	3,772	48	-	-	**3,820**
PJM	3,672	8,890	84,781	-	**97,343**	10,287	2,742	30,045	-	**43,074**
SERC-Central	294	524	290	4,321	**5,429**	964	-	-	-	**964**
SERC-East	724	130	-	-	**854**	-	-	-	-	**-**
SERC-Florida Peninsula	3,280	7,235	-	-	**10,515**	-	-	-	-	**-**
SERC-Southeast	2,574	2,814	800	5,066	**11,253**	-	-	-	-	**-**
SPP	278	444	32,170	149	**33,039**	27,535	4,604	16,892	-	**49,031**
Texas RE-ERCOT	5,146	25,461	42,802	27,053	**100,462**	26,961	12,693	6,523	7,782	**53,960**
WECC-NWPP-AB	107	607	-	300	**1,014**	1,781	1,329	-	1,450	**4,560**
WECC-NWPP-BC	2	15	15	-	**32**	717	30	-	15	**762**
WECC-CA/MX	15,429	3,913	250	13,043	**32,635**	7,477	591	99	4,005	**12,172**
WECC-NWPP-US & RMRG	4,342	7,275	1,359	3,430	**16,406**	17,868	1,257	100	3,081	**22,305**
WECC-SRSG	1,623	1,577	250	5,360	**8,810**	1,685	1,556	-	-	**3,241**
Total	40,551	70,534	219,009	71,185	**401,279**	131,672	33,473	79,382	31,318	**275,846**

Figure 14 shows the planned solar capacity for assessment areas through 2031. Texas RE-ERCOT, PJM, and MISO have the most solar capacity in planning.

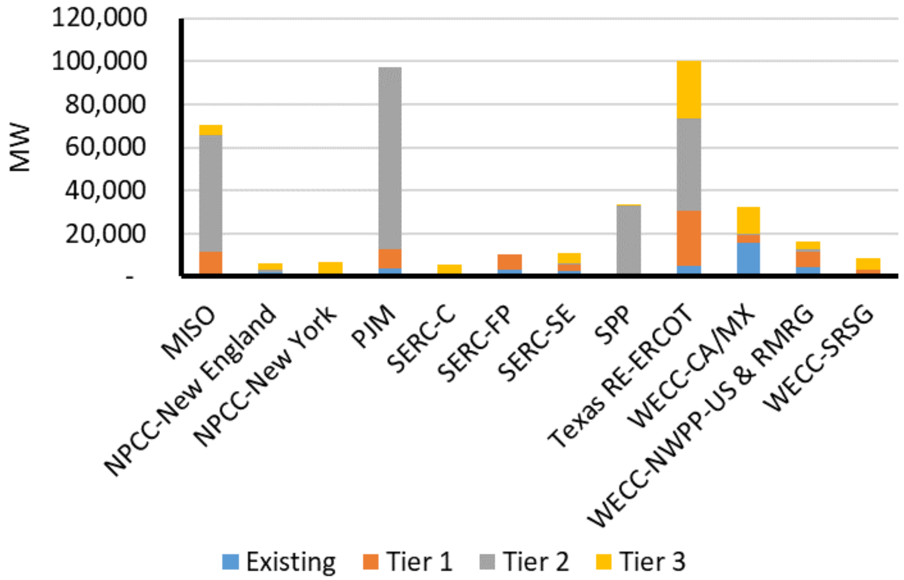


Figure 14: Solar Capacity Planned and Existing

Figure 15 shows the planned wind capacity for assessment areas through 2031. MISO, NPCC-New England, PJM, SPP, and Texas RE-ERCOT have the most wind capacity in planning.

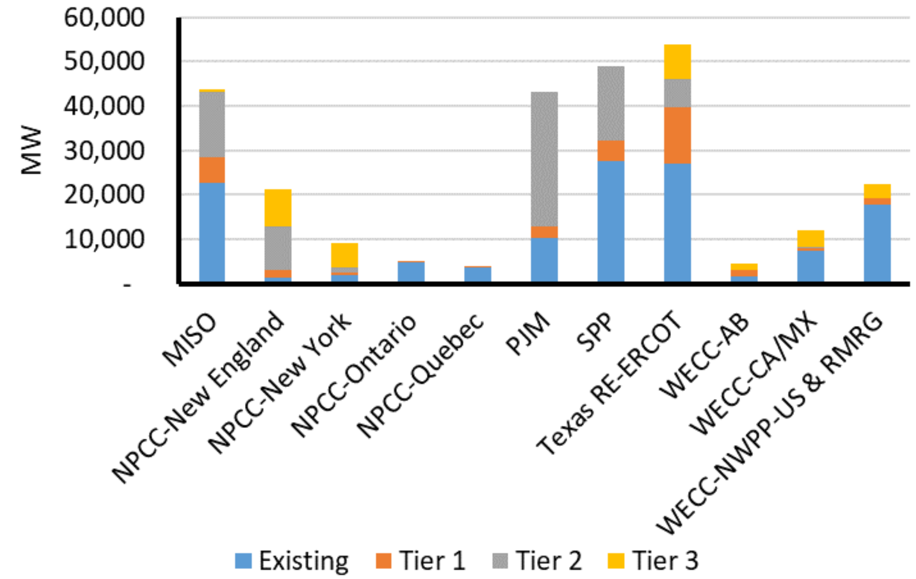


Figure 15: Wind Capacity Planned and Existing

The nameplate capacities shown in **Table 8**, **Figures 14**, and **Figure 15** are based on the design ratings of the generators and in general do not indicate the capacity that resource types will deliver to serve demand. On-peak resource capacity, in contrast, reflects the expected capacity that the resource type will provide at the hour of peak demand. Because the electrical output of VERs like wind and solar depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. **Table 9** shows the capacity contribution of existing wind and solar resources for each assessment area.

While some areas of North America have and continue to see more rapid resource mix changes, North America has a diverse fuel mix overall. A 10-year projection of North America peak capacity is shown in **Figure 16** unless they are too small to be visible. Though the changes appear to level off around 2025, new wind, solar, and natural-gas-fired generation typically are planned within five-year time horizons; such projections are based on interconnection queues and are less predictable in the latter part of the assessment period.

Table 9: 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	27,127	4,554	16.8%	8,543	4,335	50.7%
MRO-Manitoba Hydro	259	52	20.0%	-	-	-
MRO-SaskPower	627	44	7.0%	12	0	0
NPCC-Maritimes	1,181	229	19.4%	53	7	12.4%
NPCC-New England	1,486	182	12.2%	1,828	839	45.9%
NPCC-New York	2,368	339	14.3%	114	46	40.0%
NPCC-Ontario	4,946	697	14.1%	478	64	13.4%
NPCC-Québec	3,820	1,375	36.0%	10	0	0
PJM	12,949	1,948	15.0%	10,958	5,060	46.2%
SERC-Central	964	958	99.3%	818	538	65.8%
SERC-East	-	-	-	799	716	89.6%
SERC-Florida Peninsula	-	-	-	4,997	2,776	55.6%
SERC-Southeast	-	-	-	3,582	2,918	81.5%
SPP	30,425	6,419	21.1%	608	115	18.8%
Texas RE-ERCOT	38,879	9,462	24.3%	22,787	12,533	55.0%
WECC-NWPP-AB	3,110	216	6.9%	714	201	28.2%
WECC-NWPP-BC	747	155	20.7%	17	11	64.0%
WECC-CA/MX	8,069	1,105	13.7%	18,439	10,921	59.2%
WECC-NWPP-US & RMRG	19,064	2,560	13.4%	7,882	5,247	66.6%
WECC-SRSG	3,241	559	17.3%	2,800	2,022	72.2%

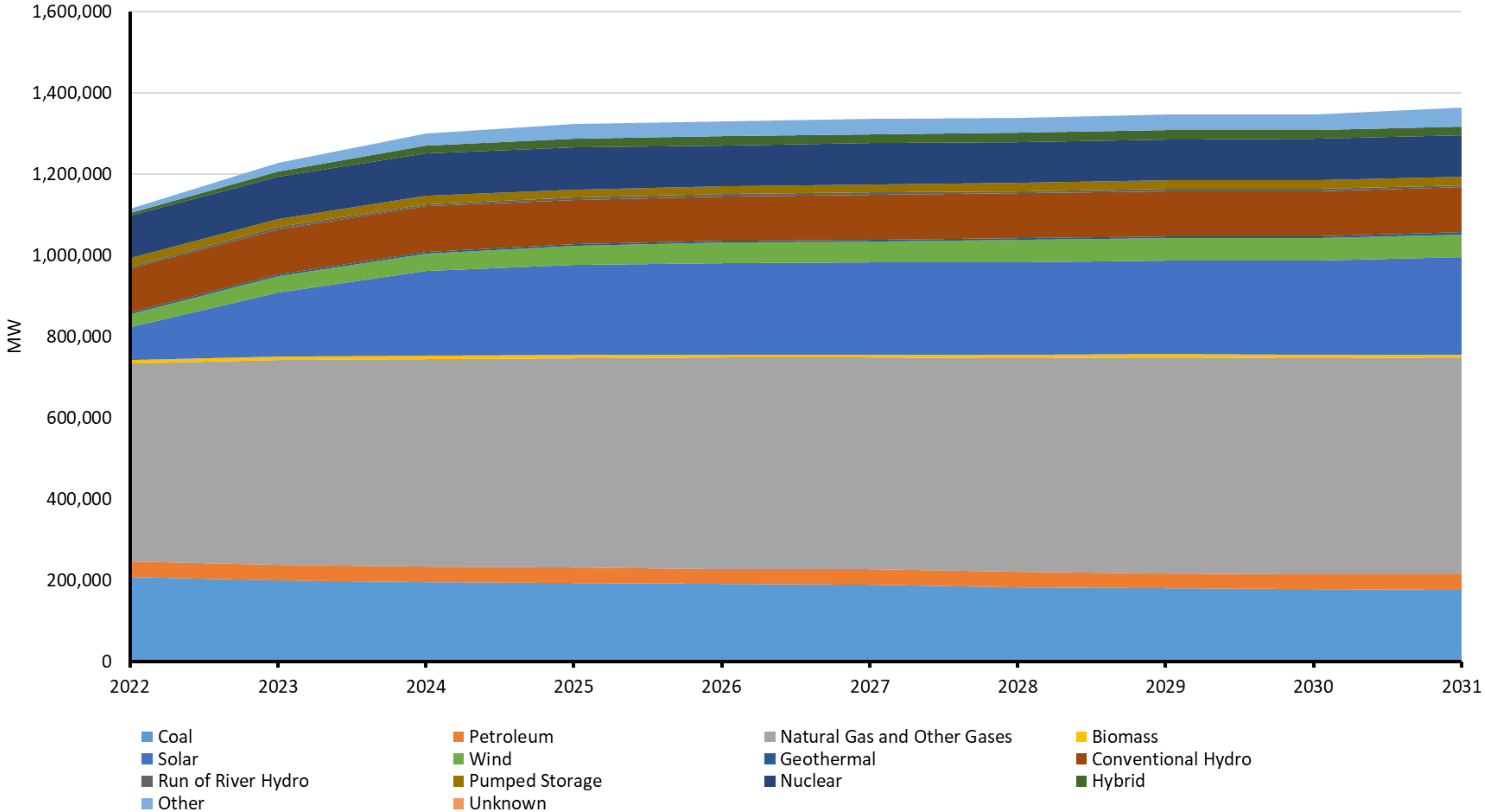


Figure 16: Existing, Tier 1, and Tier 2 Planned Resources Projected Through 2031

Generation Retirements

Figure 17 shows the net change of generating capacity since 2012 and the planned retirements for the forward looking 10-year period. Coal and petroleum both have negative net changes, confirming the trend for their replacement in favor of other resources. The capacity of coal and petroleum has fallen by over 66 GW and 7 GW, respectively, since 2012. During the same period, natural-gas-fired capacity increased by almost 120 GW.

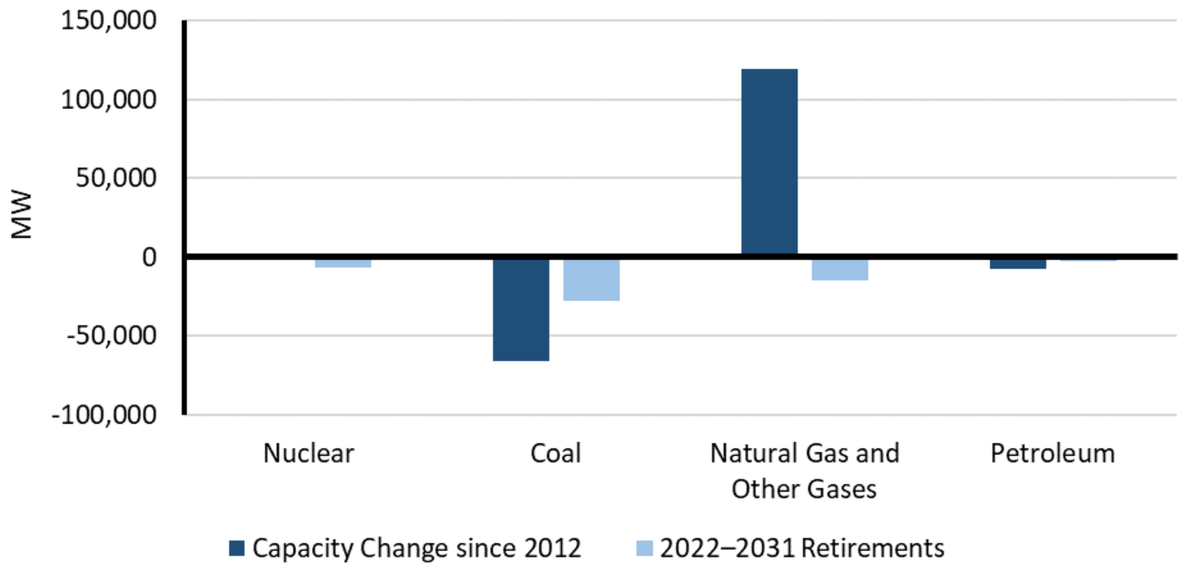


Figure 17: Capacity Changes since 2012, Retirements Projected through 2031

Figure 18 displays the capacity retirements for the previous 7-year period as well as the 10-year projected cumulative retirements through 2031. The 10-year projected retirements are based on committed retirements known to date and is expected to increase as the time horizon progresses.

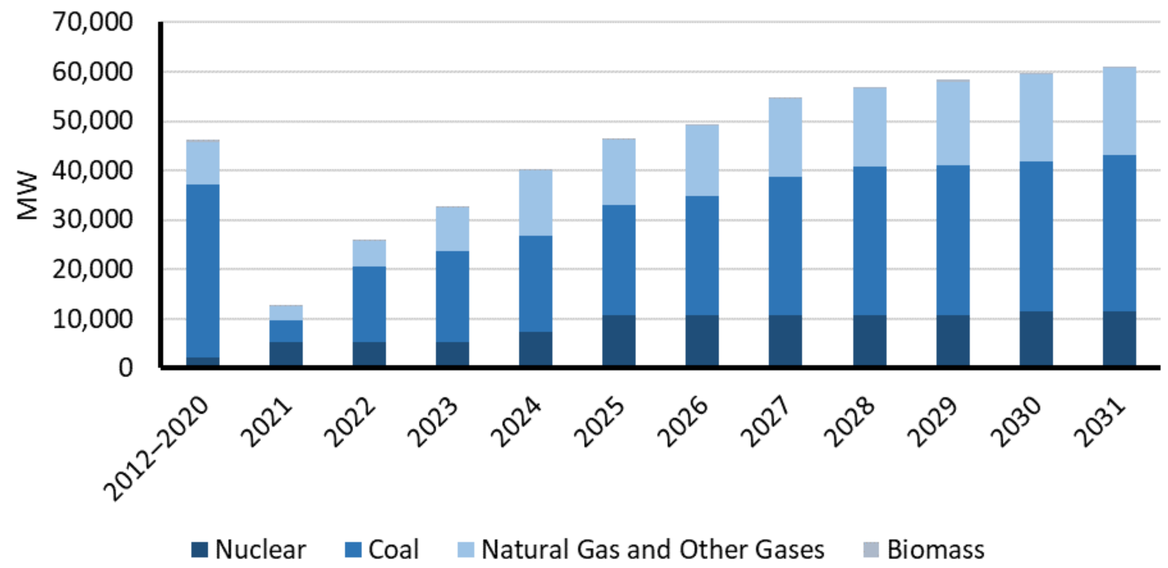


Figure 18: Capacity Retirements since 2012, Projected Cumulative Retirements through 2031

The LTRA does not predict future generator retirements but instead reports on confirmed retirements. Additional retirements beyond what is reported as confirmed in this *2021 LTRA* are to be expected and will continue to alter the resource mix. Since the *2020 LTRA*, confirmed coal-fired, nuclear, and natural-gas-fired generation retirements through the year 2026 have increased by over 27 GW (126%). Because generator retirement announcements can be made as late as 90 days prior to planned deactivation in some areas, long-range retirement projections based on confirmed retirements could be significantly understated.

Figure 19 shows the proportion of existing coal-fired generation capacity in each assessment area that is currently committed or planned for retirement.

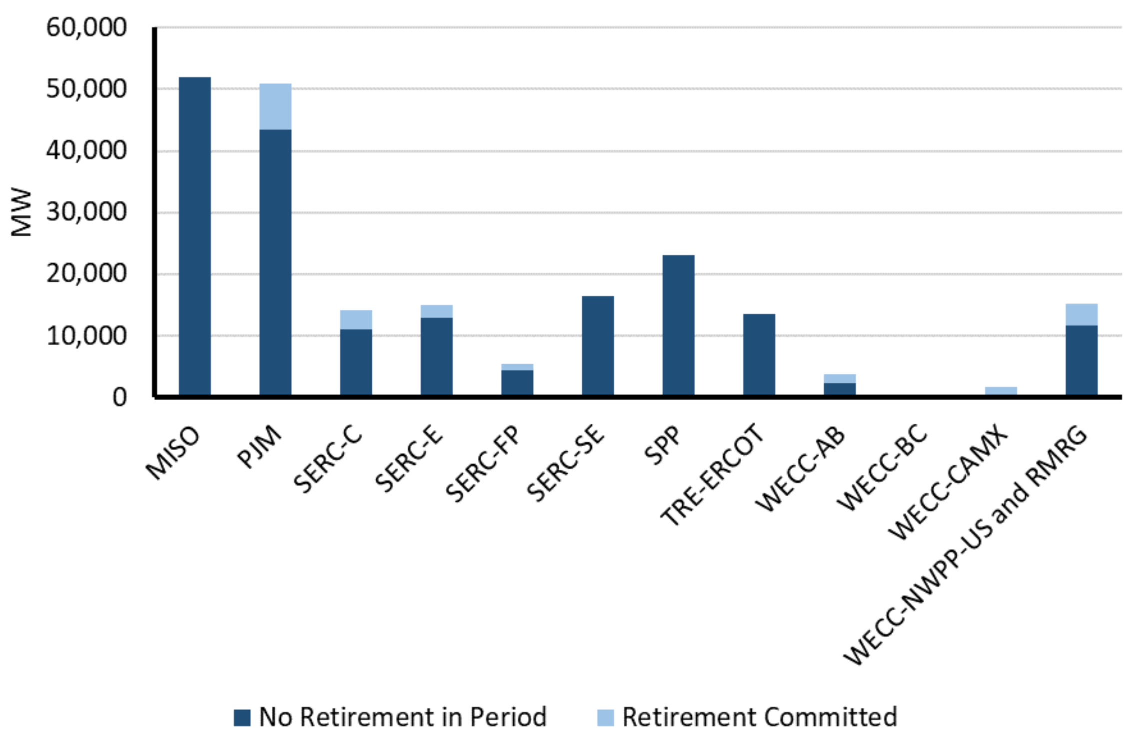


Figure 19: Portion of Existing Coal-Fired Generation Capacity with Retirement Commitments through 2026

Replacing coal-fired and nuclear generation with nonsynchronous and natural-gas-fired generation requires careful attention. Planning considerations include ensuring there is adequate inertia, ramping capability, frequency response, and fuel assurance on the system. NERC data and analysis indicate that inertia and frequency response are adequate for all Interconnections and generally trending in a positive direction as discussed in **Key Finding 4 (Frequency Response)**. As the resource mix continues to evolve, industry must be watchful not only for resource adequacy criteria but also for the ERSs that must be maintained.

Natural Gas Capacity Additions

Across the North American BPS, existing natural-gas-fired on-peak generation has increased from 280 GW in 2009 to 463 GW today (with the addition of 17 GW in natural-gas-fired generating capacity since publication of the *2020 LTRA*). Another 47 GW of natural-gas-fired generation are in Tier 1 planning for addition over the next decade as shown in **Figure 20**.

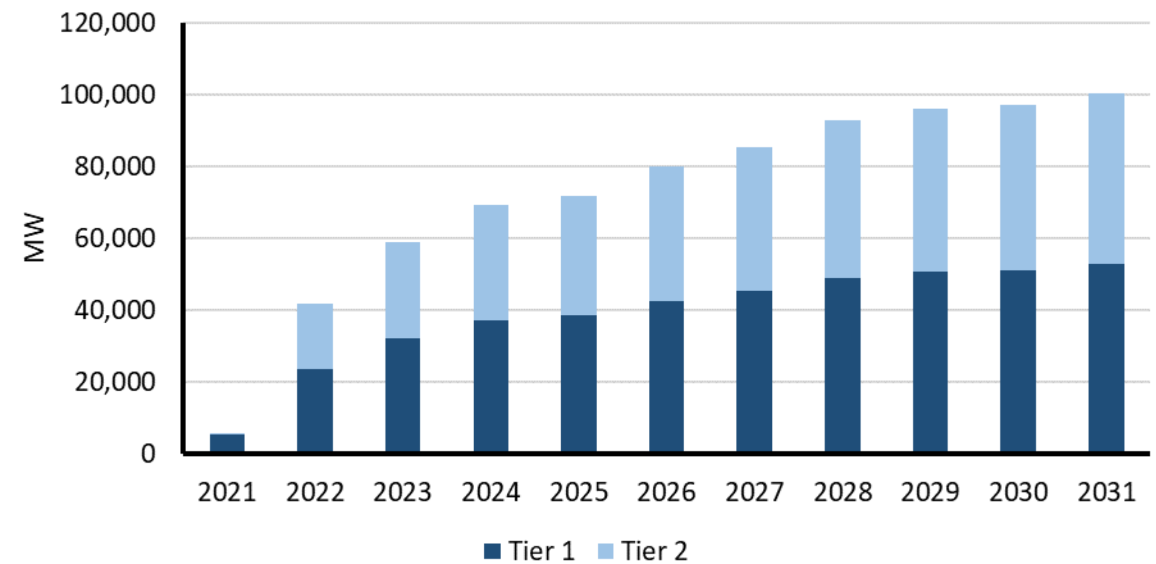


Figure 20: Natural Gas Capacity Planned Additions through 2031, Tier 1 and 2

Unlike other conventional generation with on-site storage, natural gas generation uses the natural gas pipeline system to receive “just-in-time” fuel to burn for its electricity production. Pipeline transportation service is subject to interruption and curtailment depending on the generator’s level of service. In constrained natural gas markets, generation without firm transportation may not be served during peak pipeline conditions (more prevalent in winter), and industry should make arrangements for alternative fuels. Some plants no longer have the option of burning a liquid fuel, limiting their fuel alternative when natural gas cannot be supplied. Furthermore, regardless of fuel service arrangements, natural gas generation is subject to curtailment during a force majeure event.

New England is currently fuel constrained in winter; this has been identified as one of the most significant risks to the area. Output restrictions at dual-fuel plants due to air emission regulations also contribute to this risk. With its existing fuel infrastructure, New England has faced challenging operating conditions, particularly in extreme cold weather. Given the shift in the current resource mix, these challenges are likely to extend beyond the winter season. During extreme cold periods, electricity needs have been met through a combination of generators using natural gas from pipelines, LNG, as well as the now-declining nuclear, coal, and oil-fired generators. Although new natural-gas-fired generation is being added to the fuel mix, the regional natural gas pipelines continue to have limited fuel deliverability for any power generators without firm natural gas transportation contracts. Additionally, LNG deliveries to New England that are influenced by global economics and logistics can also be uncertain without firm supply contracts. Environmental permitting for new dual-fuel capability (typically, natural gas and fuel oil) is becoming more difficult under tightening state and federal air emissions regulations. Even when these units are granted permits, their run times for burning fuel oil are usually restricted to limit their ozone season (i.e., May 1–September 30) air emissions.

Projection of Solar DERs

BTM solar PV is an increasingly prevalent DER seen across North America. BTM solar PV is defined as the solar PV resources connected directly to the distribution system. Residential rooftop solar PV comprises most of the BTM solar PV installed.

Figure 21 shows the amount of solar DER in the assessment areas through 2031. The amount of DERs is projected to more than double by 2026 and surpass 60 GW total capacity over the 10-year period.

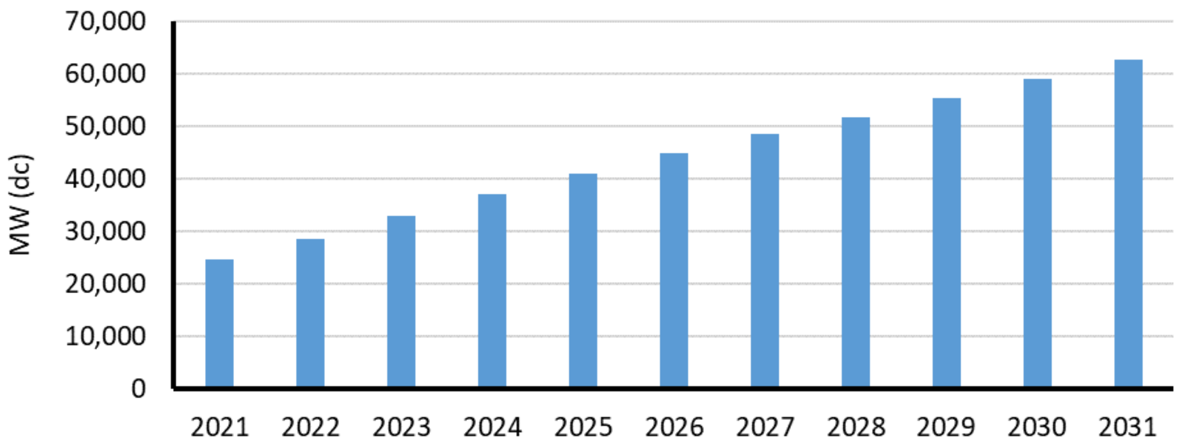


Figure 21: Cumulative Distributed Solar PV Capacity in Assessment Areas

Figure 22 shows the amount of solar DER currently installed and planned by 2031 for assessment areas with greater than 1,000 MW of capacity. Of the 20 assessment areas, 15 double their total solar DER footprint by 2031. The following are notable cumulative increases in projections since the *2020 LTRA*: NPCC-New England (869 MW, 19% increase), NPCC-New York (670 MW, 10% increase), SERC-Florida Peninsula (1,283 MW, 300% increase), and WECC-SRSG (623 MW, 13% increase). Increasing DER levels in NPCC-New York, NCPP-New England, NPCC-Ontario, and Texas RE-ERCOT are approaching levels that can impact grid reliability in some conditions, leading entities in those areas to take steps for reliable planning and operations. California and parts of the Western Interconnection have planning and operating measures in place that continue to evolve with growing DER levels.

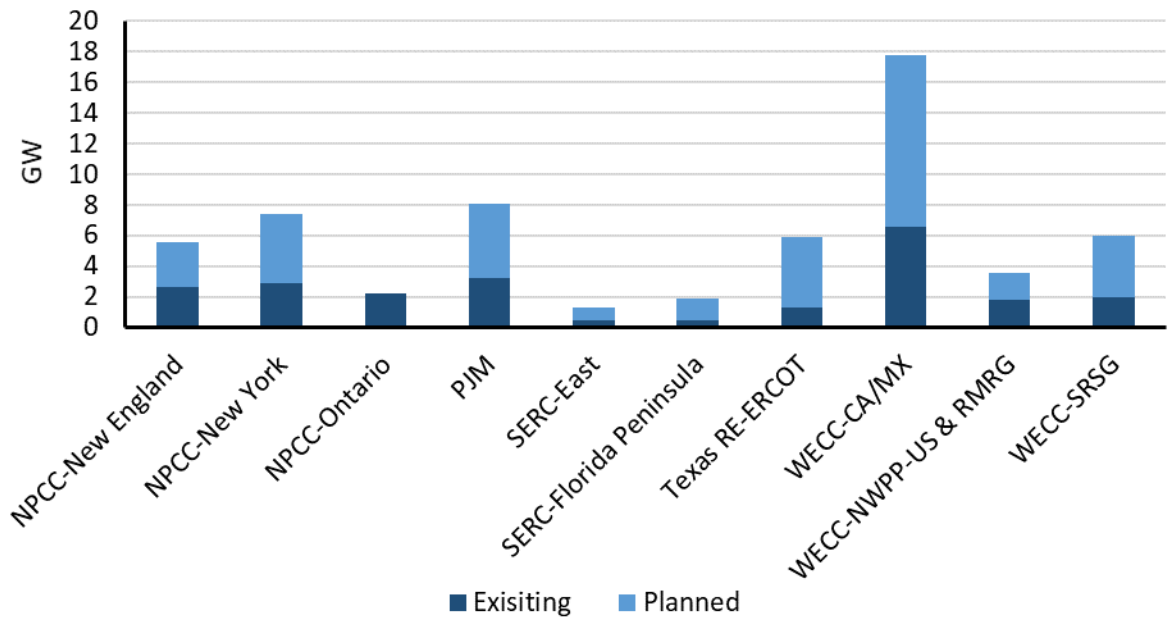


Figure 22: Solar DER by Assessment Area by 2031

At low penetration levels, the effects of DERs may not present a risk to BPS reliability; however, the effect of these resources can present certain reliability challenges that require attention, particularly as penetrations increase. This leads to areas where further consideration is needed to better understand the impacts and how those effects can be included in planning and operations of the BPS. The NERC report, *Distributed Energy Resources: Connection, Modeling, and Reliability Considerations*, provides a detailed assessment of DERs and its potential impacts to BPS reliability.[34]

[34]*NERC Distributed Energy Resources: Connection, Modeling, and Reliability Considerations*: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

System Ramping

Figure 23 shows that flexible resources may also be needed for balancing during periods of solar PV loading and unloading as solar PV is added to a particular system. This is not a completely new concern for operators as some resources and imports have a long history of nondispatchability due to physical or contractual limitations. However, variable resources (particularly solar generation due to its daily production patterns) are the primary driver leading to increased ramping requirements. Other dispatchable resources are needed in reserve to offset the lack of electricity production when variable fuels (e.g., sun, wind) are not available.

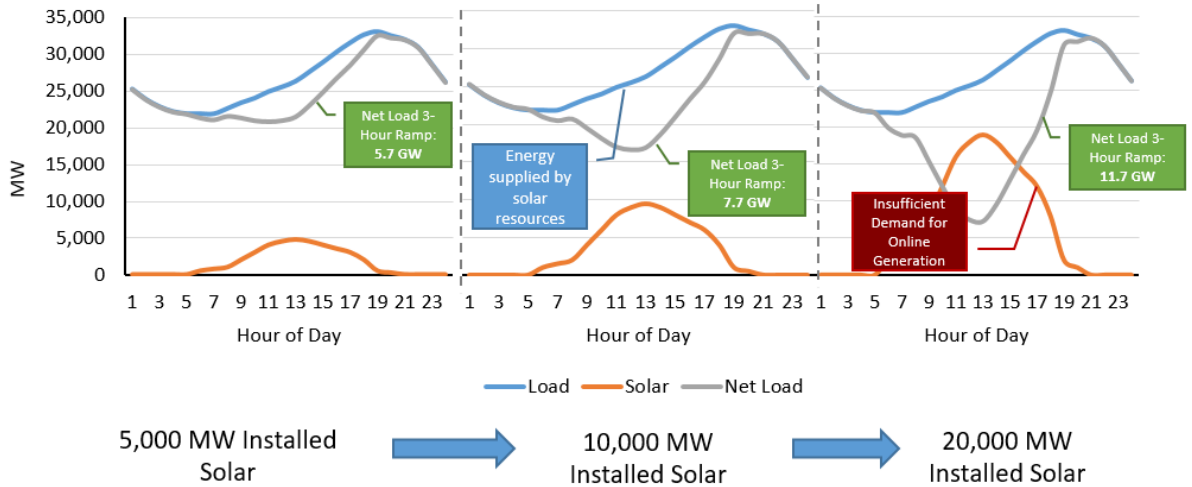


Figure 23: Example of Increasing Solar Resources Leading to Increased Ramping Requirements

> **Ramping**
>
> Ramping is a term used to describe the loading or unloading of generation resources in an effort to balance total demand with supply during daily system operations. Changes in the amount of nondispatchable resources, system constraints, load behaviors, and the generation mix can impact the needed ramp capability and amount of flexible resources needed to keep the system balanced in real-time. For areas with an increasing penetration of nondispatchable resources, the consideration of system ramping capability is an important component of planning and operations. Therefore, a measure to track and project the maximum one-hour and three-hour ramps for each assessment area can help understand the significant need for flexible resources.

California Independent System Operator (CAISO) Photovoltaic Generation and Ramping

The predominant driver for the increasing ramps in California's load patterns is the increased integration of solar PV DER generation across its footprint. For example, CAISO has over 11 GW of solar supply and must proportionally increase reserves to respond to a sudden increase in demand associated with cloud cover, rain, or inverter-related issues. Solar, rooftop or otherwise, is well dispersed throughout the state, reducing the expectations of widespread generation disruptions due to localized weather conditions (e.g., overcast skies in Northern California with clear skies in Southern California).

CAISO observed that three-hour net-load ramping has exceeded 15,000 MW. Based on current projections, monthly maximum three-hour upward net-load ramps are projected to steadily increase each year through 2023 (see Figure 24). Upward ramps are typically steep in late afternoon when solar generation output decreases while system demand is still high. Without sufficient upward ramping capability within the balancing area to offset the loss of solar output during these times, neighboring BAs would have to provide the necessary support to balance supply and demand.

Continued increases in projected maximum three-hour ramps reinforces CAISO's near-term need for access to more flexible resources in their footprint.

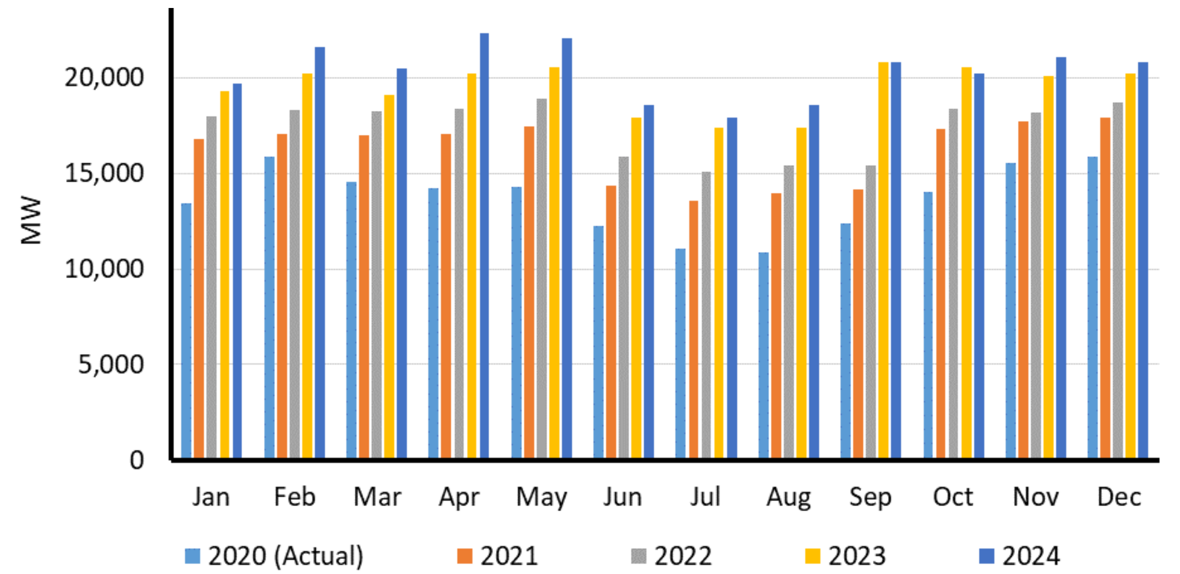


Figure 24: Maximum Three-Hour Ramps in CAISO (Actual and Projected) through 2024

Technical Development at the ERO

The NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) focuses on the BPS impacts of DERs from a transmission planning and system analysis perspective. NERC's SPIDERWG develops industry guidance and other risk mitigation solutions in four key areas:

- **Modeling:** Representing aggregate DERs in BPS reliability studies, advancing industry capabilities and expertise with representing DERs in these reliability studies, and developing robust and reasonable data sets for power flow and dynamic simulations
- **Verification:** Ensuring that the models used in studies provide a reasonable and suitable representation of the actual aggregate performance of these resources, benchmarking software platforms to ensure uniformity in tools, and recommending analysis techniques for accounting for aggregate DERs during large BPS disturbances
- **Studies:** Improving study techniques and methods to ensure the most stressed operating conditions are chosen for BPS reliability studies, identifying key operating conditions and sensitivities to perform, and improving software tools and study capabilities
- **Coordination:** Supporting coordination between transmission and distribution entities for improved data exchange and coordinating with the Institute of Electrical and Electronics Engineers (IEEE) leadership to support the application of IEEE Std. 1547-2018 across North America

The NERC SPIDERWG will develop recommended practices and guidelines around these topics to ensure registered entities have the tools and capabilities to advance transmission planning studies in light of rapidly growing penetrations of DERs. SPIDERWG also serves as an excellent forum for distribution and transmission entities to exchange ideas and sharing needs in terms of information for modeling and situational awareness. SPIDERWG also supports the review and applicability of NERC Reliability Standards and identifies whether these standards may need to be modified to ensure reliable operation of the BES in light of the potential DER impacts.[35]

Energy Storage

Energy storage provides important capabilities to maintain grid reliability and stability. With increasing requirements for system flexibility as variable generation levels increase and while energy storage technology costs decrease, bulk system and distributed energy storage applications are becoming more prevalent. Storage may be used for load shifting and energy arbitrage—the ability to purchase low-cost, off-peak energy and resell the energy during high peak, high cost periods. Storage may also provide ancillary services, such as regulation, load following, contingency reserves, and peaking capacity. This is true for both bulk storage, which acts in many ways like a central power plant, and distributed storage technologies.

Battery storage and hybrid generation resources, which combine energy storage with a generating plant (e.g., a wind or solar farm) are connecting to the grid in parts of North America, and many more projects are in BPS planning processes. Existing grid-connected battery resources and projects in development (Tiers 1, 2, and 3) for interconnection through 2025 now total over 113 GW, a substantial increase from the 47 GW reported for the same period in the *2020 LTRA* (see **Figure 25**). These quantities do not include energy storage on the distribution system. Grid planners and operators need to address modeling, study, and operating issues in the near-term for reliable integration of this growing resource type. IBRs continue to grow and provide battery storage with the opportunity to complement renewable projects in the form of hybrid facilities, which typically incorporate a battery storage component as part of a utility-scale solar or wind development. Additionally, battery storage has the capability to provide ERSs for the BPS, such as voltage support, frequency response, and system inertia, allowing for battery storage to compete with synchronous resources that provide those same necessary characteristics to the grid. Further analysis should be conducted by system planners to model a system with significant battery storage and hybrid power plants. System planners must conduct adequate studies to determine the impacts of battery energy storage systems on transmission system stability as well as the capability of storage to provide ERSs and capacity to meet reserve margin requirements. **Figure 25** shows the current and future installations of both battery and hybrid storage on the BPS through 2025. **Figure 26** contains a breakdown of these installations by assessment area.

[35] SPIDERWG information can be found on the NERC website: https://www.nerc.com/comm/PC/Pages/System-Planning-Impacts-from-Distributed-Energy-Resources-Subcommittee-(SPIDERWG).aspx

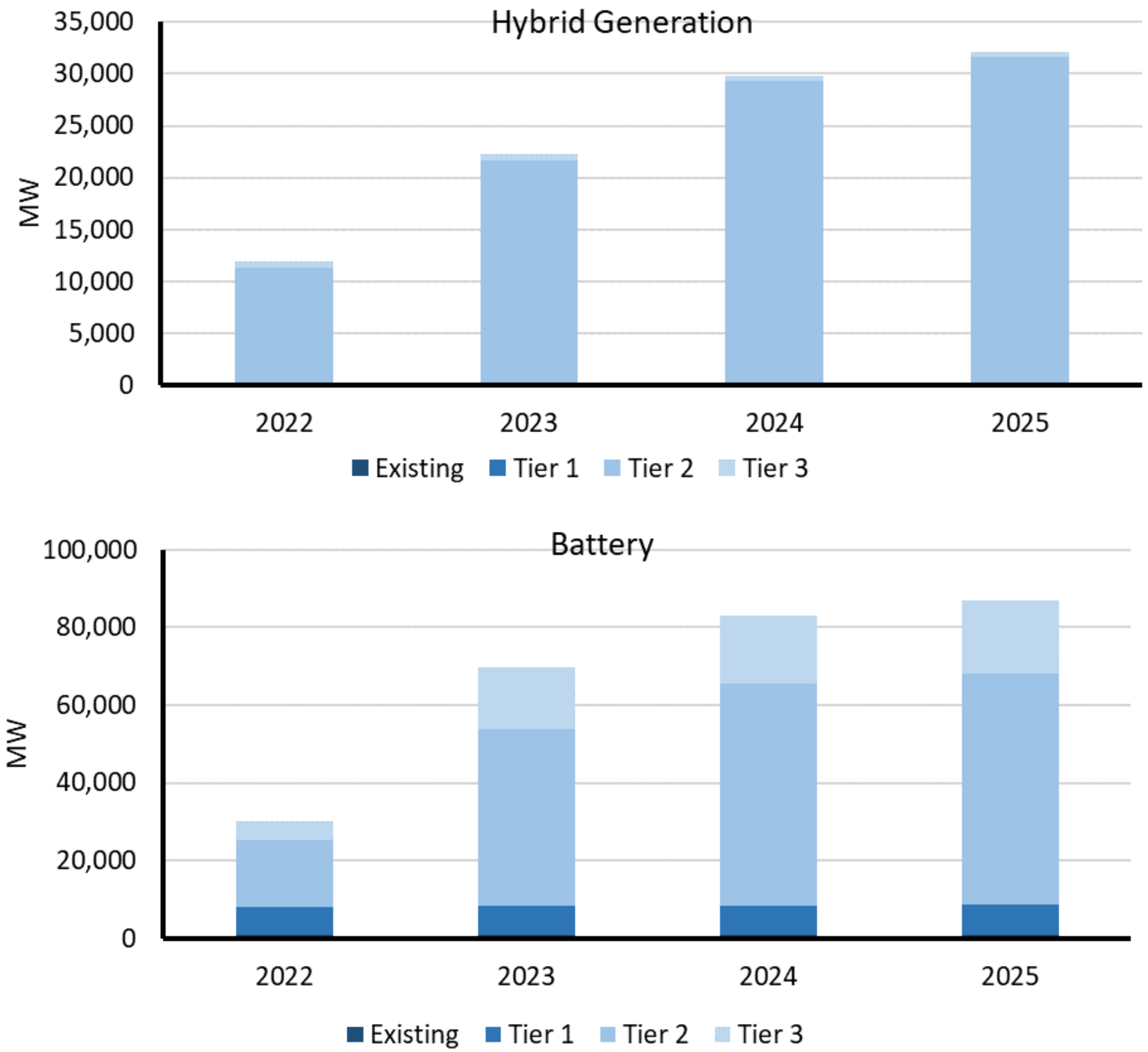


Figure 25: Grid Battery and Hybrid Generation in North America–Existing and Planning

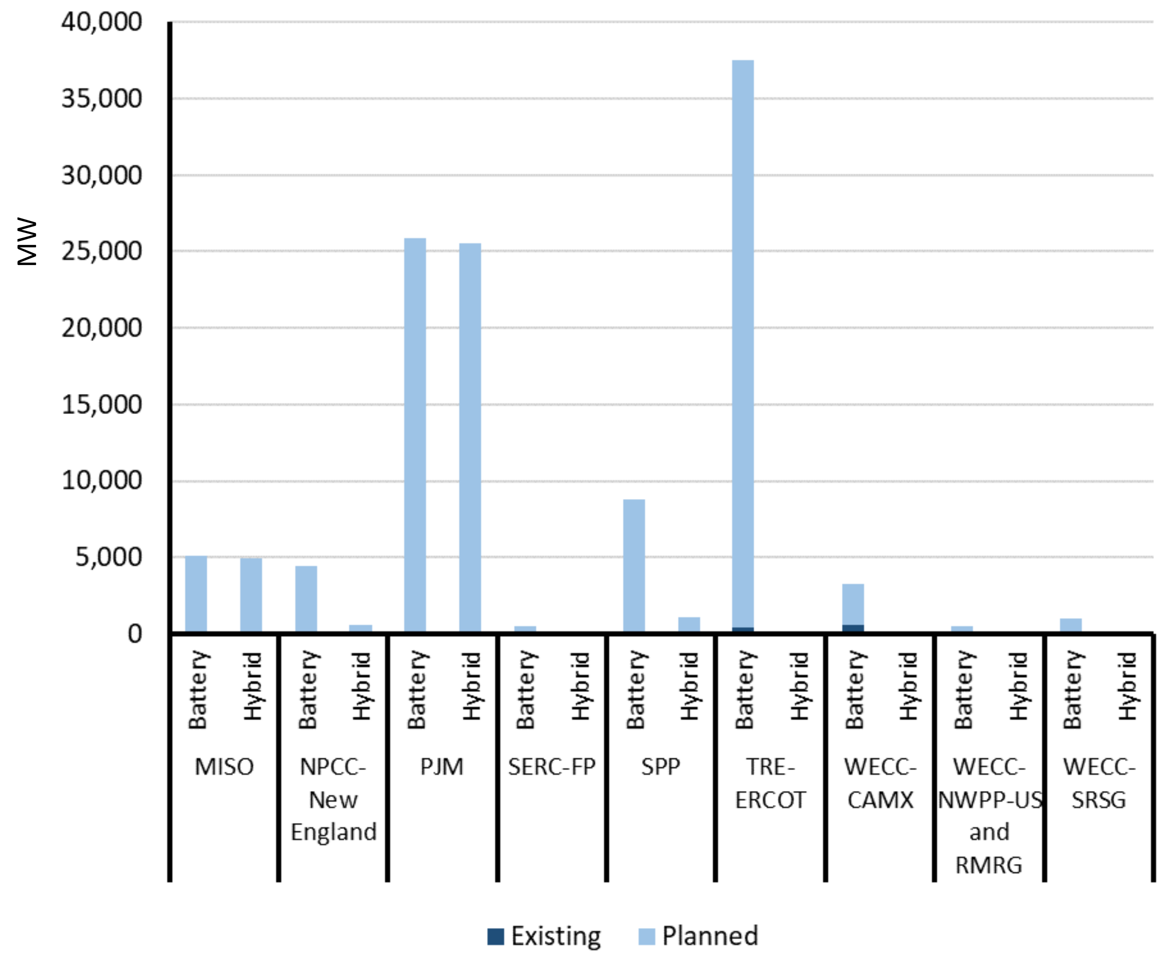


Figure 26: Grid Battery and Hybrid Generation Capacity by 2025

Managing Risks as the Resource Mix Evolves

The addition of variable resources, primarily wind and solar, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources. Important reliability implications include the following:

- **Ensuring sufficient flexible resources:** In order to maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, operators are seeing the need to have more system ramping capability. As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. This can be accomplished by adding more flexible resources within their committed portfolios or by removing system constraints to flexibility.[36] VERs can provide ramping and other ERSs, and procurement mechanisms can be used to obtain flexible resources for operator needs. The following highlighted activities are underway in areas where VERs make up a large share of the resource mix:
  - **California:** The California Independent System Operator (ISO) conducts an annual flexible capacity technical study each year to determine the flexible capacity needs of the system for up to three years into the future; this study presents the ISO's flexible capacity needs assessment and specifies the ISO's forecast monthly flexible capacity needs in year 2022.[37]
  - **Texas:** ERCOT has managed ramping needs from increasing amounts of wind generation through forecasting tools that give operators the ability to curtail wind production and/or reconfigure the system in response to wind output changes. To support reliable operations with growth in solar capacity, ERCOT is developing a short-term solar forecasting tool that can be integrated in generation dispatching in order to aid in meeting flexible needs for solar up and down ramps. Additionally, during the end of 2020 and beginning of 2021, ERCOT conducted a ramping study using a period of March and April of 2022. March and April were chosen because they tend to be high net load ramping times due to high wind output. The total amount of wind capacity, solar capacity, and storage capacity in the study period was 36.8 GW (wind), 16.3 GW (solar), and 1.1 GW (storage). Three weather-year scenarios were studied, all with high but varying levels of renewable ramping. The study examined both upward and downward ramps, but focused on upward ramping for reliability needs since downward ramping is routinely managed through dispatch protocols.
- **Planning and operating with inverter-based resources:** IBRs, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. Tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources, in some cases over wide areas. The earliest events documented by the ERO occurred in California and date back to 2016 and 2017. In May 2021, the Texas Interconnection observed its first disturbance that resulted in widespread reduction of solar PV resource power output, affecting 1,100 MW of generation.[38] Planning studies and operating models must accurately account for these newer resource types. The NERC Inverter-Based Resource Performance Working Group has published two foundational reliability guidelines that provide strong industry recommendations pertaining to the reliable integration of BPS-connected IBRs:
  - *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance* (September 2018)[39]
  - *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources* (September 2019)[40]

  Additionally, the IEEE Standards Association Project 2800 (IEEE P2800) is underway to "establish recommended interconnection capability and performance criteria for IBRs interconnected with transmission and networked sub-transmission systems." IEEE P2800 is expected to ensure that future interconnections of BPS-connected IBRs are designed and installed with the equipment and functional performance capabilities to mitigate some or all of the issues identified in past ERO disturbance analyses.

  The ERO continues to focus resources on addressing potential reliability issues associated with the ever-increasing penetration of IBRs.

[36] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERS_Measure_6_Forward_Tech_Brief_03292018_Final.pdf
[37] See CAISO 2022 Flexible Capacity Needs Assessments: http://www.caiso.com/Documents/Final2022FlexibleCapacityNeedsAssessment.pdfhttp://www.caiso.com/Documents/Final2022FlexibleCapacityNeedsAssessment.pdf
[38] See Joint NERC and Texas RE Staff Report *Odessa Disturbance | Texas Events: May 9, 2021 and June 26, 2021.* The report includes links to other ERO Event Analysis reports of disturbance-induced reduction of solar PV output*:* https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf
[39] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf
[40] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

- **Managing fuel-related risks to electricity generation (fuel assurance):** Natural gas for electricity generation is an essential fuel that bridges the rapid development of VERs. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[41] Disruptions to the fuel delivery can result from adverse events that may occur, such as line breaks, well freeze-offs, or storage facility outages. The pipeline system can be impacted by events that occur on the electricity system (e.g., loss of electric motor-driven compressors) that are compounded when multiple plants are connected through the same pipeline or storage facility. Furthermore, additional pipeline infrastructure is needed to reliably serve load.

NERC's RSTC is a standing committee that leverages expertise to study and identify solutions that reduce risks to the BPS. Past efforts by the RSTC and its subgroups have led to the publication of guidance and enhancements to Reliability Standards that address the emerging challenges as the resource mix evolves. The RSTC maintains an active work plan in continuance of these efforts.[42]

Recommendations for Key Finding 5

In addition to the recommendations found elsewhere in the report, the following will reduce risks that can occur during the resource mix transition:

- Industry planners should update interconnection agreements to address the performance specifications for IBRs covered in the NERC reliability guidelines to ensure that all resources are consistently and effectively being interconnected to the BPS.[43] FERC should also update its *pro forma* interconnection agreement for large and small generators to include IBR performance specifications. These updates should also be accompanied by clear requirements for accurate modeling and sufficiently detailed studies during time of interconnection, and they should include EMT studies where necessary.
- The ERO should continue advancing the efforts to modernize NERC Reliability Standards to account for IBR performance characteristics. This includes promptly reviewing industry's voluntary application of guidance and recommended practices contained in NERC reliability guidelines for IBR performance. Where reliability gaps are identified, NERC should develop standard requirements that support the delivery of achievable performance capabilities from BPS-connected IBRs that benefit system reliability.
- The ERO and industry should continue to focus on the improvements needed in the area of modeling and studies for reliably integrating IBRs into the BPS. This includes verifying that IBR models used for steady state and dynamic power systems analysis agree with the as-built, plant-specific settings, controls, and behaviors of the facility. The ERO and industry should also develop the techniques and procedures for more advanced EMT studies capable of identifying the full scope of abnormal performance issues during the interconnection study process so that the issues can be corrected before the plants are connected to the grid.

[41] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf
[42] See NERC RSTC page: https://www.nerc.com/comm/RSTC/Pages/default.aspx
[43] *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources:* https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

Demand, Resources, Reserve Margins, and Transmission

Demand Projections

Trends in electricity peak demand and energy growth rates in North America continue to be mixed. In the *2020 LTRA*, NERC reported that trends had leveled off or even declined after the increasing growth rates reported in the *2019 LTRA*. Heightened uncertainty in demand projections that stem from the progression of COVID-19 and the response of governments, society, and the electric industry were contributing factors. Now, growth rate increases in winter peak demand are being influenced by electrification of space heating systems. Summer peak demand growth rates are relatively flat, most likely as a result of the continued growth in DERs and some EE. See **Figure 27** for seasonal peak demand growth over the current and prior assessment periods. Overall, net energy for load for the next 10 years has increased since the *2020 LTRA* with a return to growth rates that are similar to rates reported in the three years prior to COVID-19 (see **Figure 28**).

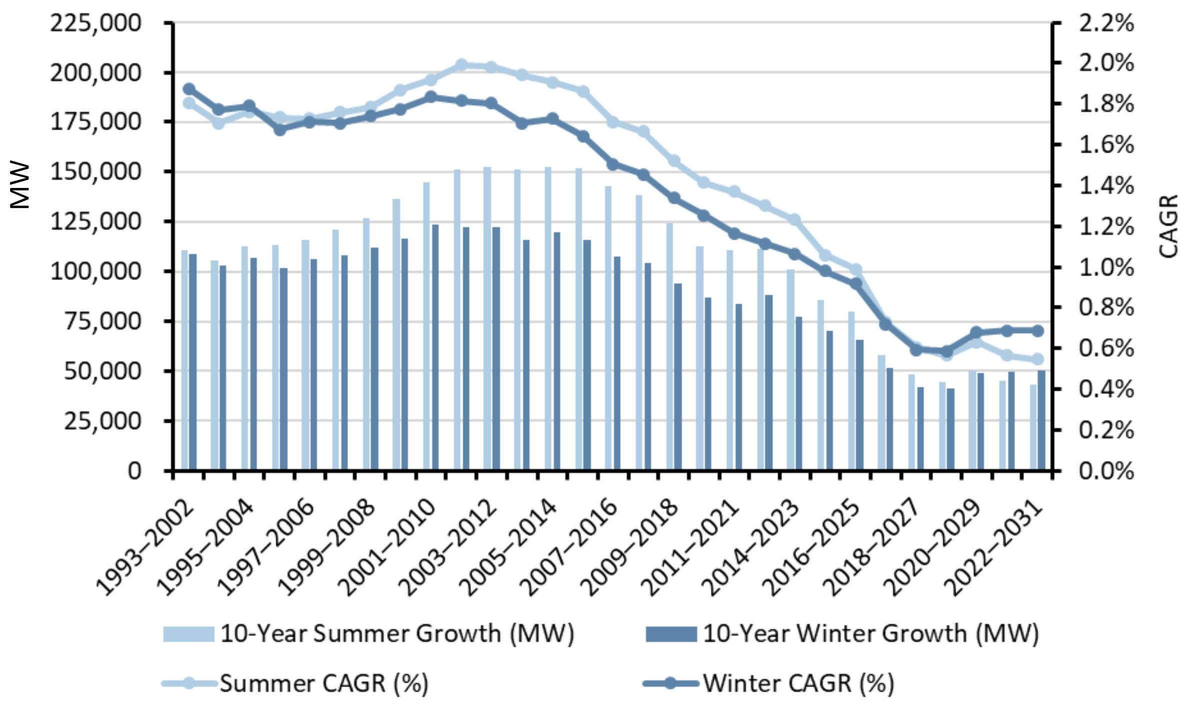


Figure 27: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

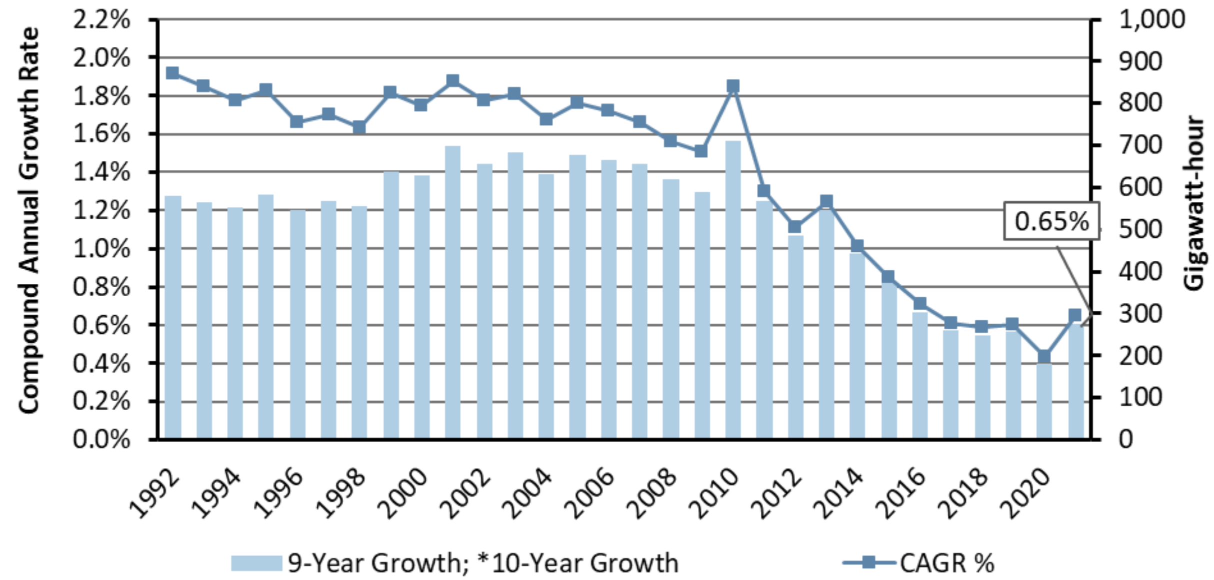


Figure 28: 10-Year Net Energy to Load Growth and Rate Projection Trends

The 10-year demand growth rate in all assessment areas is 1.0% or less per year with the exception of NPCC-Ontario (1.3%) and WECC-Southwest Reserve Sharing Group (1.45%). Only NPCC-New York and SERC-Southeast are projecting to have lower peak demand at the end of the 10-year period (see **Figure 29**).

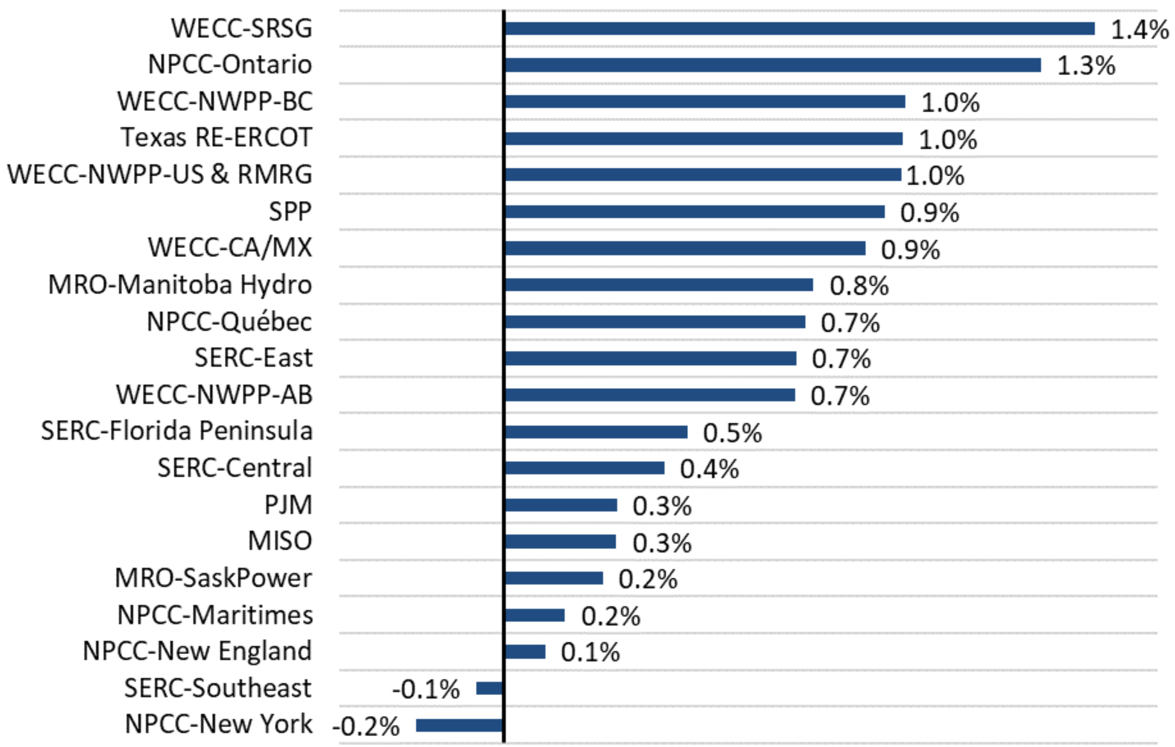


Figure 29: Annual Peak Demand Growth Rate for 10-Year Period by Assessment Area

Fuel Mix Changes

Figures 30 and 31 identify the fuel mix composition of the North American BPS generation fleet. Only generators that are connected to the BPS or participate in wholesale electricity markets are included (i.e., DERs are generally not included).

Figure 30 shows the installed capacity composition of generating resources within the BPS as of July 2021 compared to the projected installed capacity composition of 2031 (includes Tier 1 additions).

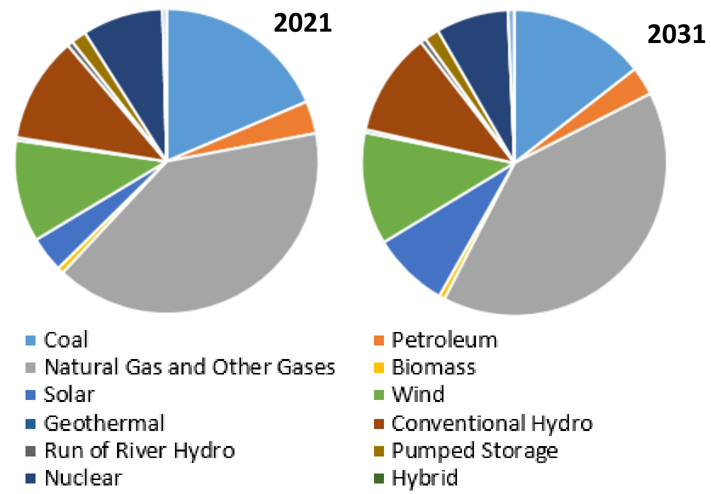


Figure 30: Installed Nameplate Capacity by Fuel Mix Trend (Includes Future Tier 1 Resources)

Figure 31 shows the on-peak capacity composition of generating resources in the North American BPS as of July 2021 compared to the projected on-peak capacity composition of 2031 (includes Tier 1 additions). On-peak capacity gives an idea of what a resource is capable of producing at peak demand.

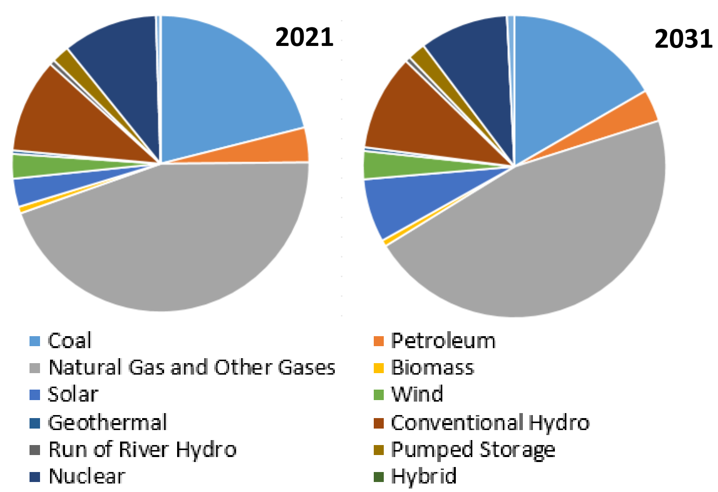


Figure 31: On-Peak Anticipated Capacity Trend by Fuel Mix

These figures indicate the evolution taking place in the generation fuel mix. In **Figure 31**, wind and solar resources grow from providing a combined 6% of on-peak contribution to 10% by the end of the assessment period. Furthermore, the on-peak wind and solar contributions have increased from the *2020 LTRA*, which showed a combined on-peak contribution of 4% for 2020 and a projected 6% in 2030.[44] Not included in these figures is the contribution of DERs—predominantly solar PV—which further increases the expected contribution of VERs to meeting peak demand.

BAs in the United States provide hourly historical demand and generation data that can be analyzed to provide an even clearer understanding of VER contribution to total generation. **Figure 32** shows monthly maximum and average contributions of wind and grid-connected solar generation for some BAs from 2020 data reported to the U.S. Energy Information Administration (EIA).[45] The depictions in **Figure 32** reveal a variety of resource mix portfolios that grid operators would have encountered in these areas in 2020. For example, in MISO, where wind and BPS solar contribute 6% of the total on-peak generating capacity (see MISO's Fuel Composition data for 2022 in the **Regional Assessments** section), the average contribution of wind and BPS solar in 2020 was 6% in the July peak season but averaged higher in all other months. Furthermore, maximum monthly contributions of wind and BPS solar resources ranged from a low of 18% to annual high of 34%. Averages and maximums were at their highest in the spring and fall shoulder months. The historical data in **Figure 32** provides a higher resolution view of how the installed resources are being used in the operating grid.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electricity industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically "equal probability" forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of demand side management (DSM) programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

[44] See Figures 33 and Figure 34, *2020 LTRA*: https://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/NERC_LTRA_2020.pdf
[45] Data from U.S. EIA, EIA-930 Hourly Electric Grid Monitor: https://www.eia.gov/electricity/gridmonitor/about

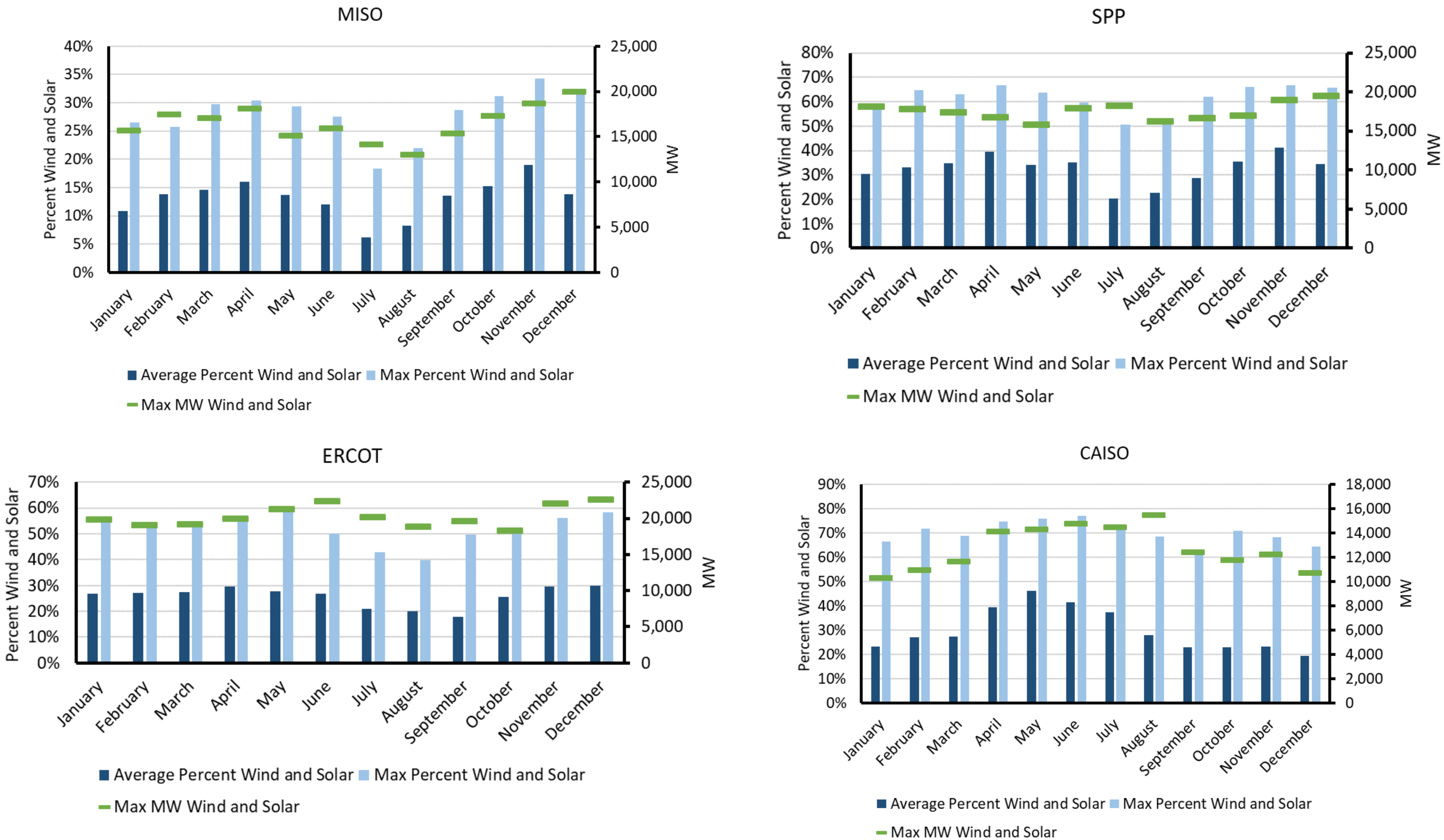


Figure 32: Monthly Wind and BPS Solar Contributions in 2020 for Selected Balancing Authorities

Reserve Margin Projections

The PRMs for the years 2022–2026 are shown in **Table 10**. **Table 11** shows the RMLs for each assessment area.

Table 10: Planning Reserve Margins (2022–2026)						
Assessment Area	**Reserve Margins (%)**	**2022**	**2023**	**2024**	**2025**	**2026**
MISO	Anticipated Reserve Margin	24.1%	19.4%	17.8%	15.8%	15.1%
	Prospective Reserve Margin	38.7%	49.5%	51.7%	51.7%	51.2%
	Reference Margin Level	18.3%	18.3%	18.3%	18.3%	18.3%
MRO-Manitoba	Anticipated Reserve Margin	20.4%	18.1%	17.0%	18.5%	14.0%
	Prospective Reserve Margin	21.4%	19.1%	18.0%	19.6%	15.0%
	Reference Margin Level	12.0%	12.0%	12.0%	12.0%	12.0%
MRO-SaskPower	Anticipated Reserve Margin	28.7%	26.2%	36.1%	31.0%	32.3%
	Prospective Reserve Margin	28.7%	27.3%	37.2%	32.1%	33.3%
	Reference Margin Level	11.0%	11.0%	11.0%	11.0%	11.0%
NPCC-Maritimes	Anticipated Reserve Margin	19.4%	20.6%	20.1%	21.9%	22.0%
	Prospective Reserve Margin	19.4%	20.7%	18.4%	20.2%	20.3%
	Reference Margin Level	20.0%	20.0%	20.0%	20.0%	20.0%
NPCC-New England	Anticipated Reserve Margin	29.9%	30.0%	29.9%	24.6%	26.1%
	Prospective Reserve Margin	34.7%	41.0%	44.9%	42.2%	50.6%
	Reference Margin Level	13.6%	13.4%	13.5%	13.5%	13.5%
NPCC-New York	Anticipated Reserve Margin	19.3%	17.3%	17.9%	17.7%	18.3%
	Prospective Reserve Margin	19.7%	20.2%	24.6%	24.4%	25.0%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Ontario	Anticipated Reserve Margin	20.8%	17.3%	21.0%	15.6%	4.9%
	Prospective Reserve Margin	22.0%	18.5%	22.1%	16.7%	6.0%
	Reference Margin Level	19.1%	15.9%	19.4%	23.1%	18.9%
NPCC-Québec	Anticipated Reserve Margin	12.8%	11.9%	11.2%	13.7%	12.8%
	Prospective Reserve Margin	15.8%	14.8%	14.2%	16.6%	15.7%
	Reference Margin Level	10.8%	10.8%	10.8%	10.8%	10.8%
PJM	Anticipated Reserve Margin	35.9%	42.2%	44.1%	43.6%	43.3%
	Prospective Reserve Margin	52.0%	71.8%	94.0%	105.4%	108.9%
	Reference Margin Level	14.5%	14.4%	14.4%	14.4%	14.4%

Table 10: Planning Reserve Margins (2022–2026)						
Assessment Area	**Reserve Margins (%)**	**2022**	**2023**	**2024**	**2025**	**2026**
SERC-Central	Anticipated Reserve Margin	31.4%	34.5%	33.7%	30.9%	34.4%
	Prospective Reserve Margin	39.4%	42.2%	43.8%	41.0%	44.2%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-East	Anticipated Reserve Margin	27.4%	27.0%	27.2%	25.5%	25.6%
	Prospective Reserve Margin	27.4%	27.7%	27.9%	26.2%	26.3%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Florida Peninsula	Anticipated Reserve Margin	19.3%	19.6%	18.8%	18.6%	21.4%
	Prospective Reserve Margin	20.8%	21.8%	21.6%	22.0%	24.8%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Southeast	Anticipated Reserve Margin	37.1%	39.7%	42.1%	41.6%	42.5%
	Prospective Reserve Margin	38.7%	42.3%	45.0%	44.5%	45.4%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SPP	Anticipated Reserve Margin	33.3%	31.5%	30.3%	29.0%	28.5%
	Prospective Reserve Margin	41.0%	39.1%	37.8%	36.4%	35.9%
	Reference Margin Level	16.0%	16.0%	16.0%	16.0%	16.0%
Texas RE-ERCOT	Anticipated Reserve Margin	26.2%	34.8%	34.4%	33.2%	32.0%
	Prospective Reserve Margin	33.2%	71.3%	83.9%	81.9%	80.5%
	Reference Margin Level	13.75%	13.75%	13.75%	13.75%	13.75%
WECC-NWPP-AB	Anticipated Reserve Margin	29.4%	28.2%	27.5%	26.4%	25.4%
	Prospective Reserve Margin	32.7%	34.8%	34.0%	32.9%	31.9%
	Reference Margin Level	13.2%	14.1%	13.4%	13.3%	13.2%
WECC-NWPP-BC	Anticipated Reserve Margin	22.3%	26.2%	28.0%	26.9%	25.7%
	Prospective Reserve Margin	22.5%	26.4%	28.1%	27.0%	25.8%
	Reference Margin Level	13.2%	14.1%	13.4%	13.3%	13.2%
WECC-CA/MX	Anticipated Reserve Margin	27.8%	26.2%	24.8%	18.9%	12.9%
	Prospective Reserve Margin	29.6%	28.9%	28.8%	22.8%	16.8%
	Reference Margin Level	18.4%	17.4%	19.0%	18.7%	18.6%

Table 10: Planning Reserve Margins (2022–2026)						
Assessment Area	**Reserve Margins (%)**	**2022**	**2023**	**2024**	**2025**	**2026**
WECC-NWPP-US & RMRG	Anticipated Reserve Margin	21.5%	24.5%	22.8%	20.1%	16.9%
	Prospective Reserve Margin	21.9%	26.2%	24.7%	21.9%	18.7%
	Reference Margin Level	13.6%	15.2%	14.0%	13.7%	13.5%
WECC-SRSG	Anticipated Reserve Margin	31.0%	27.2%	27.1%	26.7%	27.0%
	Prospective Reserve Margin	31.9%	28.1%	27.9%	27.5%	27.8%
	Reference Margin Level	12.4%	11.1%	10.8%	10.7%	12.2%

Table 11: Reference Margin Levels for Each Assessment Area (2022–2026)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	18.3%	PRM	Yes: Established Annually[46]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	11.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
NPCC-Maritimes	20.0%[47]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Subareas; NPCC
NPCC-New England	13.4–13.6%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[48]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria

[46] In MISO, the states can override the MISO PRM.

[47] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[48] The NERC LTRA RML for NY is 15%; however, there is no planning reserve margin criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs 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 2021–2022 IRM at 20.7%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

Table 11: Reference Margin Levels for Each Assessment Area (2022–2026)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
NPCC-Ontario	18.9–23.1%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	10.8%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro Québec, NPCC Criteria
PJM	14.4–14.8%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, Reliability*First* BAL-502-RFC-02 Standard
SERC-Central	15.0%[49]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-East	15.0%[50]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0%[51]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[52]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SPP	16.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP RTO Staff and Stakeholders
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-NWPP-AB	13.2–14.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-NWPP-BC	13.2–14.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-CA/MX[54]	17.4–19.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-NWPP-US & RMRG	13.5–15.2%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-SRSG	10.7–12.4%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]

[49] SERC does not provide RMLs or resource requirements for its subareas. However, SERC members perform individual assessments to comply with any state requirements.
[50] SERC does not provide RMLs or resource requirements for its subareas. However, SERC members perform individual assessments to comply with any state requirements.
[51] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[52] SERC does not provide RMLs or resource requirements for its subareas. However, SERC members perform individual assessments to comply with any state requirements.
[53] WECC's Reference Margin Level in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[54] California is the only state in the WI that has a wide-area PRM, currently 17.5%:.https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

Transmission

Historical Trend

Figure 33 shows the historical 10-year transmission projections for the past 10 years, each year being a 10-year projection. Between the years 2010 and 2016, considerably more transmission was planned than in recent years. For example, in 2012, nearly 40,000 circuit miles of high voltage transmission was planned for the next 10 years. NERC's transmission projection data is limited to planned projects and does not identify completed projects.

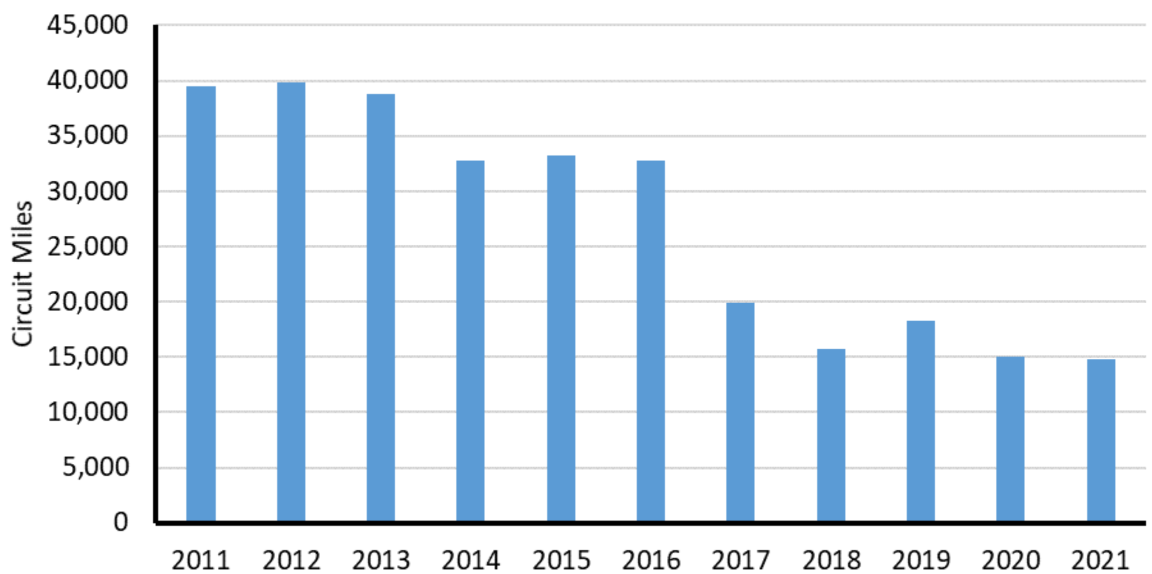


Figure 33: Historical 10-Year Transmission Projections

Future Projections

Figure 34 highlights that transmission additions during the 10-year period include plans for over 14,000 circuit miles, including conceptual projects. NERC continues to monitor the progress of transmission projects across North America. This amount represents a considerable reduction in the amount of transmission miles planned in nearly a decade compared with the 30,000+ miles planned each year during the period of 2011–2016 (see Figure 35). Integrating new wind and solar generation in the BPS requires ISO/RTOs and utility planners to dedicate considerable resources to transmission system planning processes.

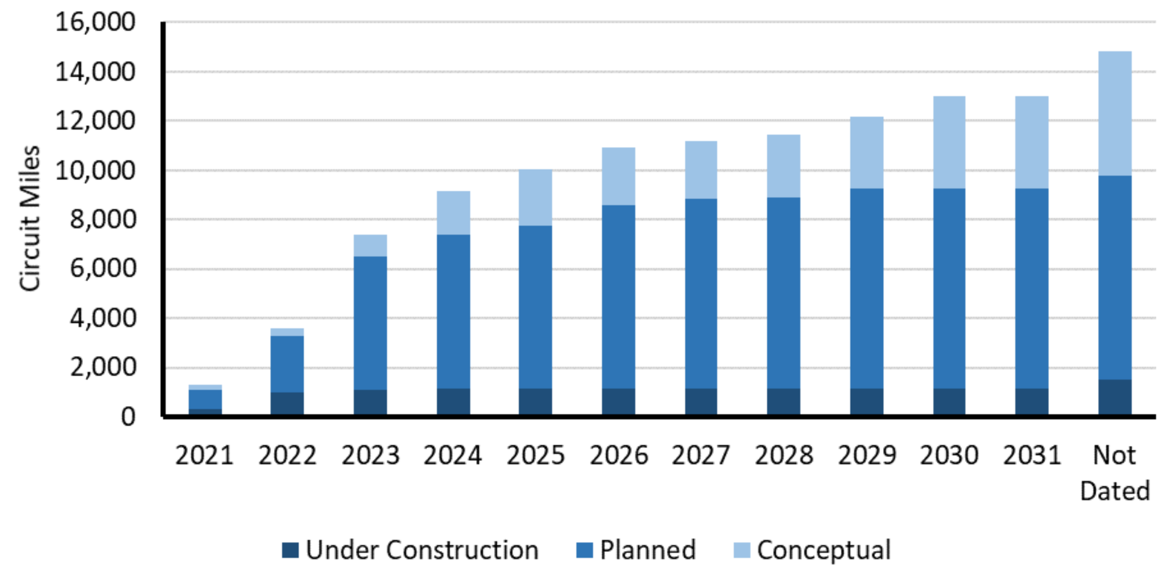


Figure 34: Future Transmission Circuit Miles >100 kV by Project Status

Future Transmission Project Categories

Under Construction: Construction of the line has begun.

Planned (any of the following):

- Permits have been approved to proceed
- Design is complete
- Needed in order to meet a regulatory requirement

Conceptual (any of the following):

- A line projected in the transmission plan
- A line that is required to meet a NERC TPL standard or powerflow model and cannot be categorized as "Under Construction" or "Planned"
- Other projected lines that do not meet requirements of "Under Construction" or "Planned"

Figure 35 shows the future transmission circuit miles by voltage class.

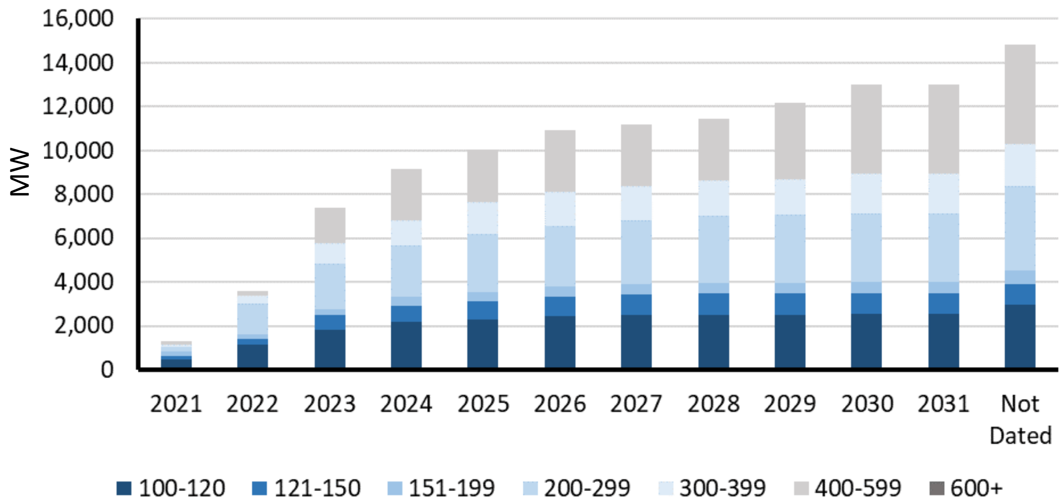


Figure 35: Future Transmission Circuit Miles >100 kV by Voltage Class
(No projects at 600 kV or greater are in development)

Figure 36 shows that most planned transmission projects are shorter in line length and that fewer longer length projects are being planned. However, with the amount of solar and wind coming on-line in the next 10 years, area planning processes may identify needs for longer length transmission projects to capture and transmit renewable energy from areas distant from load centers.

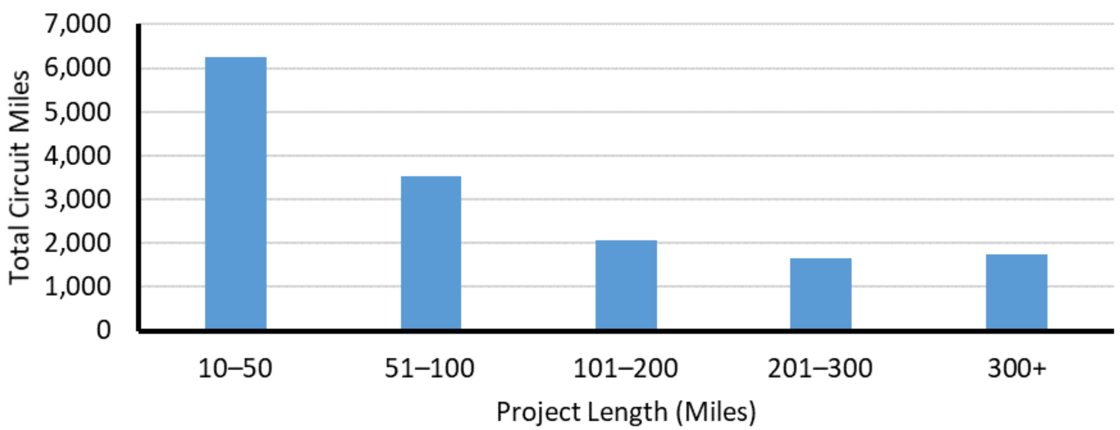


Figure 36: Line Miles Projected through 2030

Figure 37 shows the percentage of future transmission circuit miles by primary driver. According to industry, new transmission projects are being driven to support new generation and enhance reliability. Other reasons include congestion alleviation and addressing aging assets and infrastructure. Compared to the *2020 LTRA*, the categories of both *Reliability* and *Economics/Congestion* had the largest increases (0.4 points of percent) in reported justification. The need to integrate variable and renewable generation also increased as reported justification for new future transmission development from 9% in 2020 to 11% in 2021

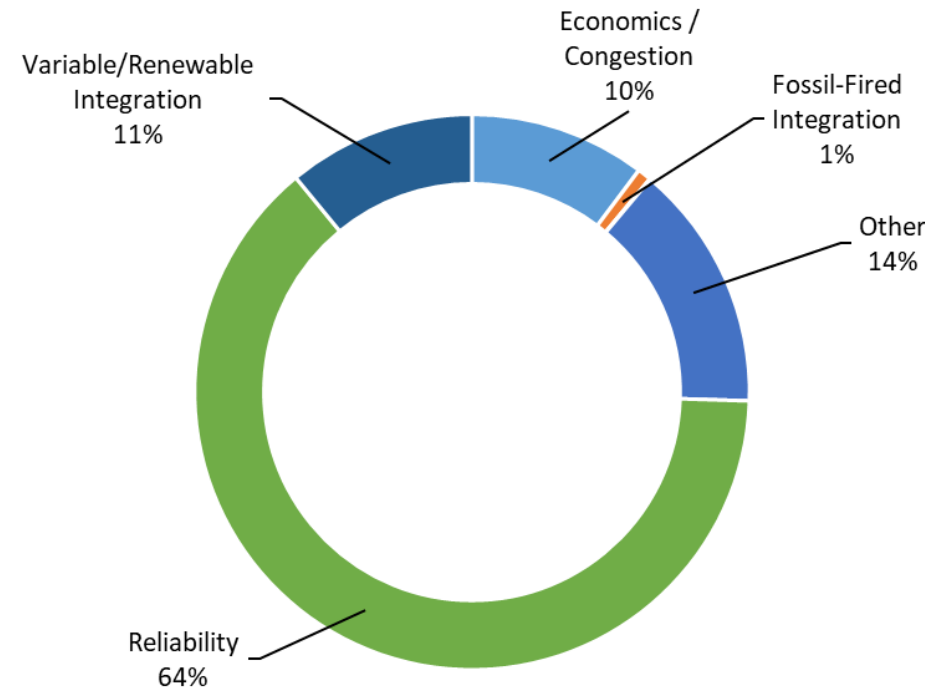


Figure 37: Future Transmission Circuit Miles by Primary Driver

Figure 38 shows the assessment areas as net importers or exporters for the year 2022. Net importers are shown in yellow and net exporters are shown in blue. The grey assessment areas are below 100 MW of capacity imported or exported for 2022.

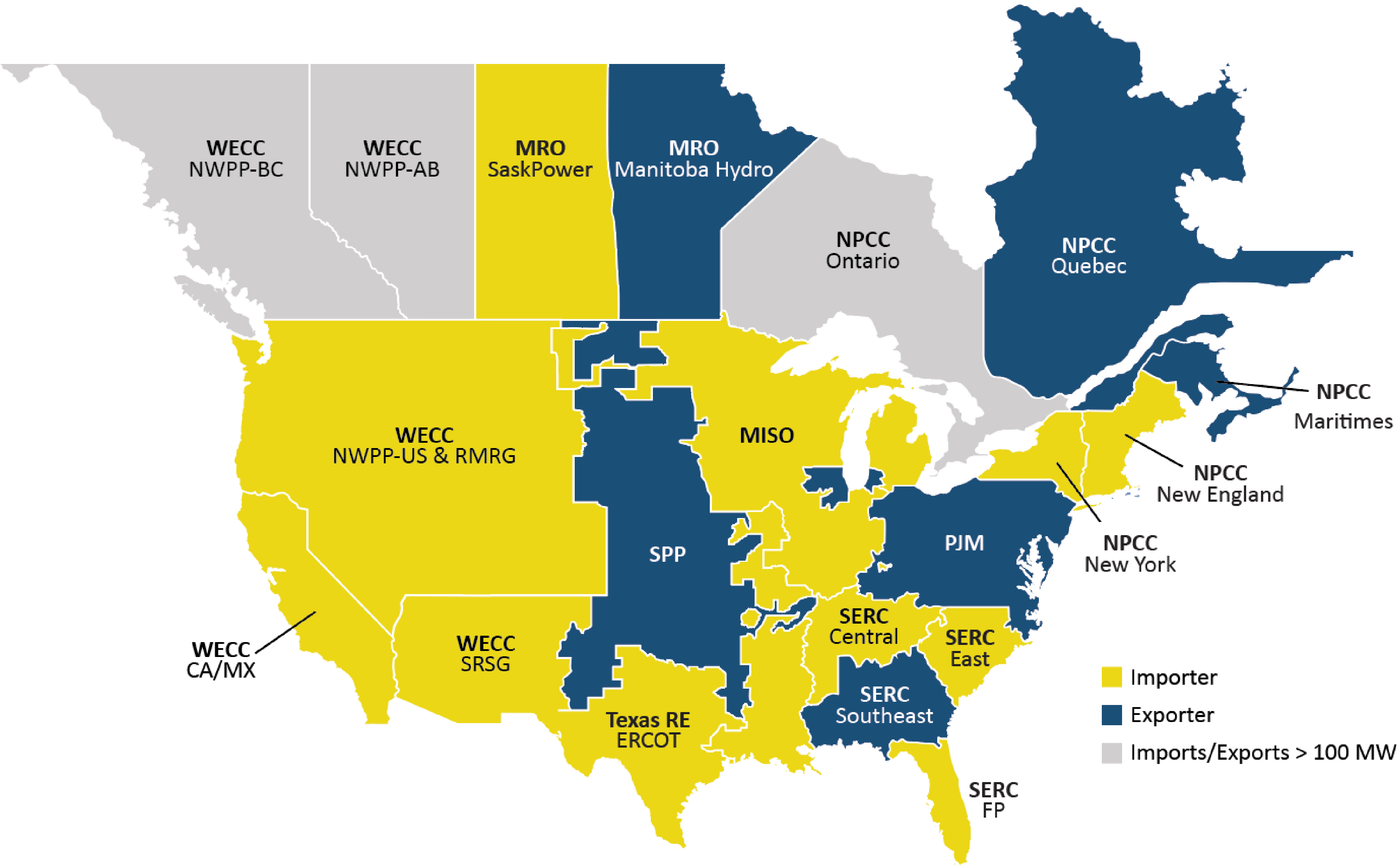


Figure 38: Net Capacity Transfers for Year 2022

Table 12 shows the percent of the reserve margin that is supported by net transfers. If an assessment area has a positive percentage (Blue), it is a net importer. Conversely, if an assessment area has a negative percentage (Red), it is a net exporter.

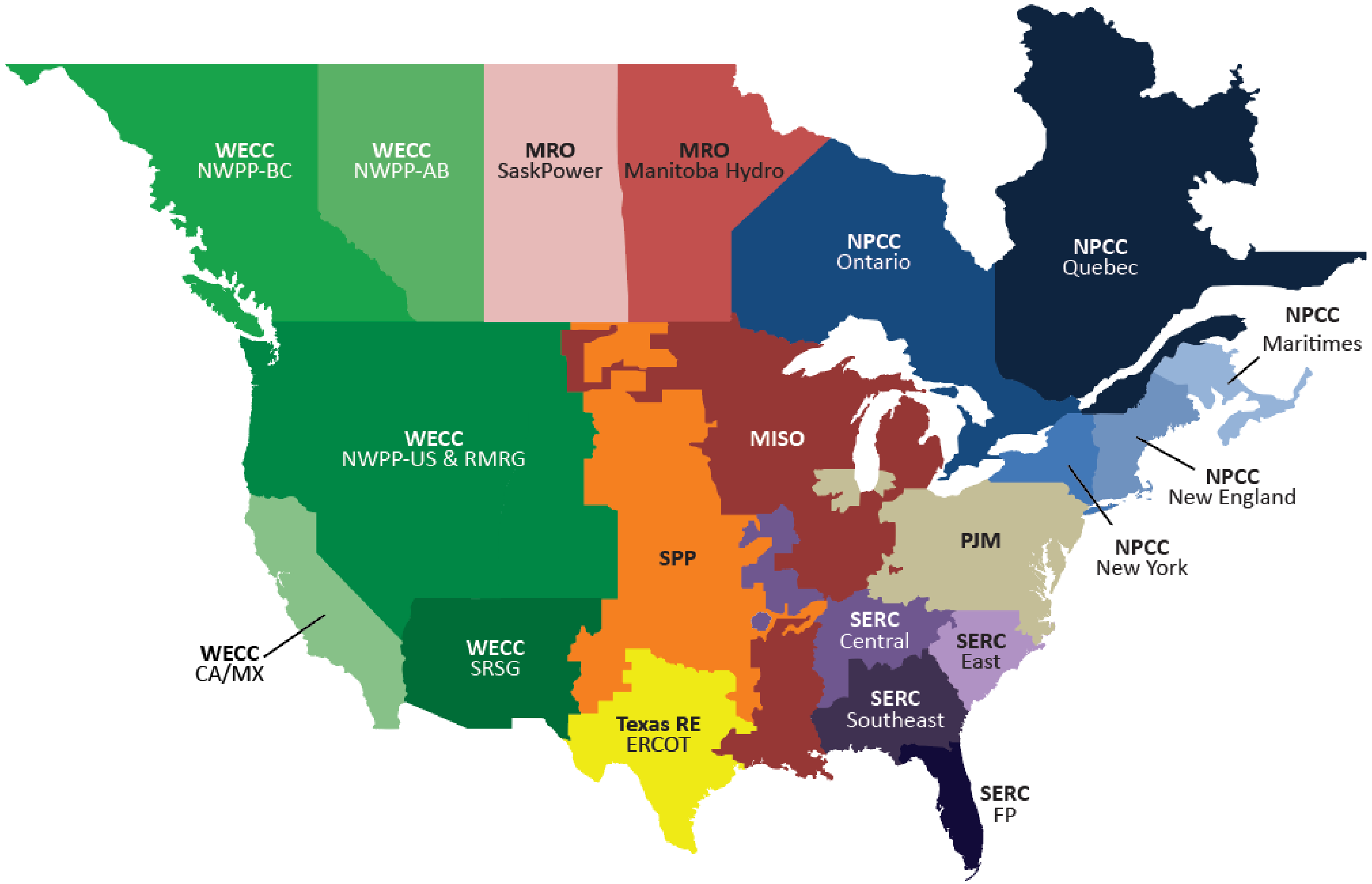
Table 12: Year 2022 Net Capacity Transfers by Assessment Area					
Assessment Area	**Peak Demand (MW)**	**Firm Net Transfers (MW)**	**Reserve Margin (MW)**	**Percent of Reserve Margin**	**Anticipated Capacity Resources**
MISO	115,465	2,097	23,557	7.5%	143,320
MRO-Manitoba Hydro	4,493	-566	916	-61.8%	5,409
MRO-SaskPower	3,669	290	1,055	27.5%	4,724
NPCC-Maritimes	5,418	-149	1,044	-14.3%	6,462
NPCC-New England	24,107	1,292	7,133	18.1%	31,240
NPCC-New York	31,356	1,811	6,055	29.9%	37,411
NPCC-Ontario	21,959	0	4,574	0.0%	26,532
NPCC-Québec	37,172	-417	4,765	-8.8%	41,937
PJM	141,142	-4,837	43,131	-11.2%	184,273
SERC-Central	38,490	101	9,862	1.0%	48,352
SERC-East	42,089	562	10,234	5.5%	52,323
SERC-Florida Peninsula	48,559	1,414	9,382	15.1%	57,941
SERC-Southeast	45,645	-548	16,948	-3.2%	62,593
SPP	51,181	-329	16,872	-2.0%	68,053
Texas RE-ERCOT	76,633	210	18,206	1.2%	94,839
WECC-NWPP-AB	11,771	0	3,458	0.0%	15,229
WECC-NWPP-BC	11,420	0	2,547	0.0%	13,967
WECC-CA/MX	54,862	2,444	15,272	16.0%	70,134
WECC-NWPP-US & RMRG	69,058	7,008	18,653	37.6%	87,711
WECC-SRSG	24,811	1,128	7,699	14.7%	32,510

Regional Assessments

The following regional assessments were developed based on data and narrative information collected by NERC from the REs on an assessment area basis. The RAS, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information. A summary of the key data is provided in **Table 13**.

Table 13: Summary of 2026 Peak Projections by Assessment Area and Interconnection (MW)

Assessment Area	Net Internal Demand (MW)	Annual Net Energy for Load (GWh)	Net Transfers (MW)	Anticipated Capacity Resources	Anticipated Reserve Margin
MISO	117,247	678,284	1,262	134,937	15.1%
MRO-Manitoba Hydro	4,709	24,591	-587	5,367	14.0%
MRO-SaskPower	3,678	24,899	315	4,864	32.3%
NPCC-Maritimes	5,437	28,147	0	6,632	22.0%
NPCC-New England	23,801	126,557	0	29,779	25.12%
NPCC-New York	30,504	145,330	1,952	36,071	18.25%
NPCC-Ontario	22,422	143,853	0	26,166	4.93%
NPCC-Québec	37,331	200,662	-145	42,110	12.8%
PJM	143,363	796,824	0	197,780	37.96%
SERC-Central	39,615	217,021	101	48,773	23.1%
SERC-East	43,111	218,996	562	52,286	21.3%
SERC-Florida Peninsula	50,379	247,614	479	61,149	21.38%
SERC-Southeast	45,751	248,966	-430	65,212	42.54%
SPP	53,306	292,141	-188	69,014	29.47%
Texas RE-ERCOT	80,322	457,854	210	107,708	34.10%
WECC-NWPP-AB	12,154	88,274	0	15,245	25.4%
WECC-NWPP-BC	11,859	67,148	0	14,903	25.7%
WECC-CA/MX	57,350	266,530	1,108	64,763	12.93%
WECC-NWPP-US & RMRG	72,490	377,285	7,317	84,753	16.92%
WECC-SRSG	26,373	109,137	2,289	32,637	27.00%
EASTERN INTERCONNECTION	583,323	3,193,223	3,466	732,391	25.6%
QUÉBEC INTERCONNECTION	30,504	200,620	-145	42,712	40.0%
TEXAS INTERCONNECTION	80,322	457,854	210	107,708	34.1%
WESTERN INTERCONNECTION	180,225	908,374	10,714	212,300	17.8%



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

MRO – Midwest Reliability Organization

- MRO-Manitoba Hydro
- MRO-SaskPower
- SPP

NPCC – Northeast Power Coordinating Council

- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

SERC – SERC Reliability Corporation

- SERC-East
- SERC-Central
- SERC-Southeast
- SERC-Florida Peninsula

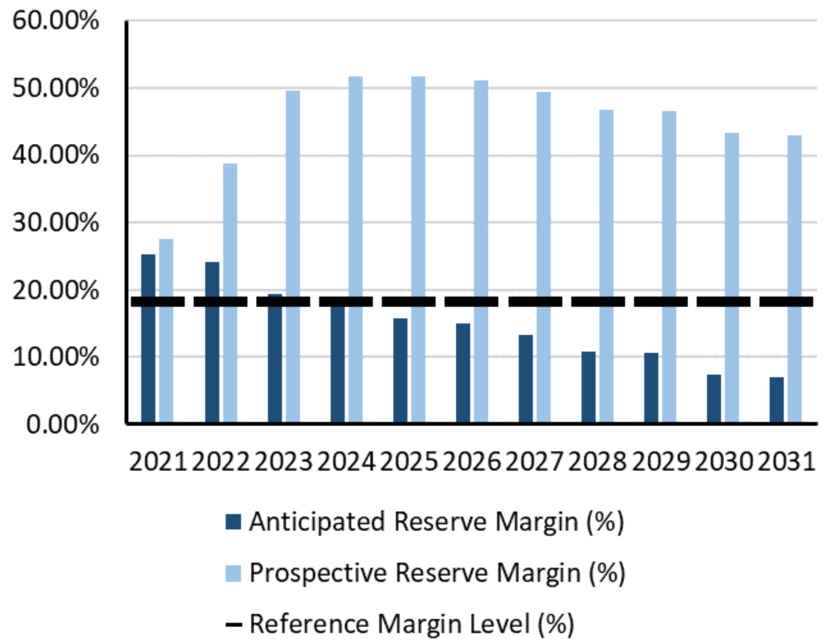
Texas RE – Texas Reliability Entity

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

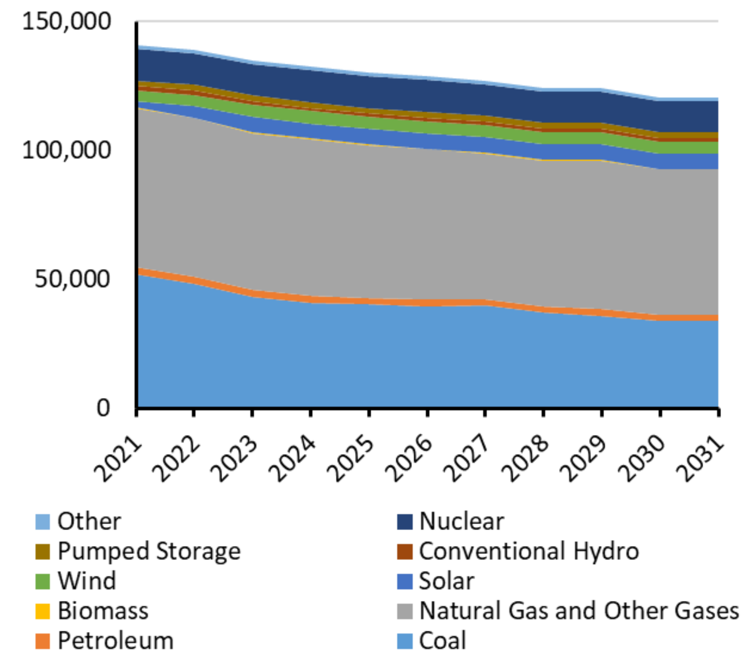
WECC

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

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	121,782	123,175	123,529	123,670	123,755	124,053	124,229	124,472	124,635	124,846
Demand Response	6,317	6,401	6,402	6,428	6,508	6,597	6,603	6,689	6,771	6,834
Net Internal Demand	115,465	116,774	117,127	117,242	117,247	117,456	117,626	117,783	117,864	118,012
Additions: Tier 1	6,715	8,933	8,513	8,513	9,040	8,513	8,513	9,040	8,513	8,513
Additions: Tier 2	16,832	35,195	39,681	42,145	42,295	42,295	42,295	42,295	42,295	42,295
Additions: Tier 3	249	1,012	1,623	3,704	4,299	4,776	6,642	7,118	7,370	7,396
Net Firm Capacity Transfers	2,097	2,102	2,107	1,262	1,262	1,167	1,172	1,177	1,177	784
Existing-Certain and Net Firm Transfers	136,605	130,500	129,484	127,219	125,897	124,632	121,835	121,246	118,105	117,870
Anticipated Reserve Margin (%)	24.1%	19.4%	17.8%	15.8%	15.1%	13.4%	10.8%	10.6%	7.4%	7.1%
Prospective Reserve Margin (%)	38.7%	49.5%	51.7%	51.7%	51.2%	49.4%	46.8%	46.5%	43.3%	42.9%
Reference Margin Level (%)	18.3%	18.3%	18.3%	18.3%	18.3%	18.3%	18.3%	18.3%	18.3%	18.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO could face the loss of over 13 GW of resource capacity from 2021 to 2024 based on its annual survey of members. These unconfirmed retirements include 10.5 GW of coal-fired generation and 2.4 GW of natural-gas-fired generation. A capacity shortfall of over 560 MW in 2024 would result if all of these unconfirmed retirements were to occur without additional new generation resources (on top of the 8 GW already in development for interconnection by 2024).
- The February 2021 cold weather event highlights the need for planning beyond just meeting an annual summer peak. MISO is developing changes to its resource adequacy construct with stakeholders that will focus on shifting capacity procurement to a seasonal basis and improved resource accreditation to reflect seasonal capabilities.

MISO Fuel Composition (MW)										
Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	48,369	43,119	41,136	40,508	39,711	39,777	37,146	35,955	33,788	33,788
Petroleum	2,730	2,694	2,694	2,454	2,454	2,454	2,444	2,444	2,444	2,444
Natural Gas	61,360	60,975	60,447	59,063	58,367	56,672	56,589	57,814	56,321	56,321
Biomass	345	345	336	336	336	265	233	228	195	195
Solar	4,335	5,910	5,955	5,955	5,955	5,955	5,955	5,955	5,955	5,955
Wind	4,541	4,656	4,714	4,706	4,703	4,698	4,667	4,636	4,636	4,636
Geothermal	0	0	0	0	0	0	0	0	0	0
Conventional Hydro	1,486	1,325	1,325	1,323	1,323	1,323	1,323	1,323	1,323	1,323
Run of River Hydro	0	0	0	0	0	0	0	0	0	0
Pumped Storage	2,290	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258
Nuclear	12,400	12,400	12,400	12,400	12,400	12,400	12,400	12,400	12,400	12,400
Hybrid	0	0	0	0	0	0	0	0	0	0
Other	1,290	1,267	1,265	1,242	1,242	1,242	1,242	1,242	1,242	1,242
Batteries	0	0	0	0	0	0	0	0	0	0
Total MW	139,147	134,950	132,531	130,246	128,749	127,044	124,257	124,255	120,562	120,562

MISO Assessment

Planning Reserve Margins

MISO estimates adequate reserves for the 2021–2022 planning year, reporting lower load and replacement of more capacity than was retired since the *2020 LTRA*. However, continued action and coordination with MISO members will be critical to ensuring resource adequacy into the future. In most of the MISO area, LSEs with oversight by the applicable state or local regulators are responsible for resource adequacy. While MISO has no authority over resource planning and cannot direct construction of generation, assessments like the OMS-MISO surveys are conducted annually to highlight resource adequacy issues, populate the LTRA, and to inform MISO members in their resource planning efforts. These proactive collaborative efforts (along with ongoing changes to the MISO resource adequacy construct) through the Resource Availability and Need (RAN) effort are a part of the shared Reliability Imperative. These efforts help to get MISO members and regulators focused on needed enhancements to ensure adequate resources as the generation fleet evolves and loss of load risk profiles potentially change.

The February 2021 cold weather event reinforced the need for these reforms and highlight the need for planning beyond just meeting an annual summer peak.[55] The next major phases of the RAN effort will focus on shifting to a sub-annual capacity construct and improved resource accreditation to reflect seasonal capabilities, especially under tight conditions.

MISO members reported more potential retirements in this year's LTRA over last year. However, when considering approaching resource replacements and potential additions through the MISO generator interconnection queue, there are expected to be sufficient resources going forward as the MISO fleet continues to evolve. Every year, assessments like the OMS-MISO survey and the NERC LTRA present a snapshot in time to look at a particular range of outcomes. If MISO members retired generation as reported with no additional replacement capacity, the reserve margin could quickly decline as the existing reserve margin and ARM suggest. However, with a robust generator interconnection queue, sufficient capacity is expected when considering all prospective capacity contributing to the prospective reserve margin in the *2021 LTRA* even with a shift from baseload generation to ever increasing VERs.

Demand

The peak demand forecast decreased from last year by approximately 2.6 GW, largely due to COVID-related decline. The five-year regional demand growth remained stable at a relatively flat 0.2%. It is unclear yet how electrification of transportation and other sectors will drive future growth, but anticipated electrification is examined fully in the MISO Transmission Expansion Plan or Process.

Demand Side Management

DR programs continue to play an important role in providing capacity. There are approximately 400 MW of additional DR in 2021 compared to the prior year for a total of 6.2 GW, and this is expected to grow at approximately 1% annually to 6.8 GW in 2031. EE no longer makes up any portion of the DSM capacity shown and may be another reason why reported load forecasts do not reflect as much electrification.

Distributed Energy Resources

While DERs are anticipated to play a larger role into the future, MISO is still working with stakeholders on adequate methods for aggregating, reporting, and allowing DER participation in MISO markets. FERC granted MISO an extension on the Order 2222 compliance filing deadline in order to permit more time to coordinate with members on appropriate DER treatment. MISO has approximately 800 MW of installed solar PV DER.

Generation

Since the *2020 LTRA*, MISO has received 1.5 GW of formal retirement requests of largely coal and natural gas: 1.3 GW of coal and 0.2 GW of natural gas. The larger retirement values in this *2021 LTRA* are indicated by the voluntary OMS-MISO Survey process. If only firm retirements were reported, MISO would be resource sufficient throughout the period, but MISO conservatively solicits voluntary responses from member unit owner/operators to assess potential resource outcomes. This approach allows MISO and its members to discuss potential future resource deficiencies well in advance. With this understanding, the LTRA presents a wide band of resource adequacy outcomes.

The MISO generator interconnection queue continues to show a steady anticipated transition to ever increasing levels of VERs and inclusion of battery storage and hybrid resources in the future generation fleet mix. That, along with the potential retirements from the survey, indicates a decarbonization of the fleet seen across the industry. Extreme weather events of the past several

[55] *The February Arctic Event, February 18-21, 2021*, MISO: https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf

years continue to stress the importance of ensuring that the MISO resource adequacy construct sends the appropriate planning and operating signals, ensuring members continue to perform reliably.

Capacity Transfers

Net firm transfers with neighboring areas declined from the *2020 LTRA* and continue to decline as reported in this *2021 LTRA*. It is unclear if actual imports will decline in the future or if the current decline only reflects the termination dates of any existing agreements, but the continuation of any existing transfers could help to address declining reserve margins. It should also be noted that non-firm transfers have played a critically important role in maintaining reliability during extreme weather events. Internal to MISO, the regional directional transfer limit between the MISO North/Central planning area and the South planning area permits the sharing of approximately 1,900 MW of capacity from the South area, currently with excess capacity to the North/Central area. There is approximately 3 GW of capacity in 2021 that are not available to the North/Central planning area because of this constraint. As the fleet shifts and retirements occur, this quantity for trapped capacity is expected to decrease over the next several years.

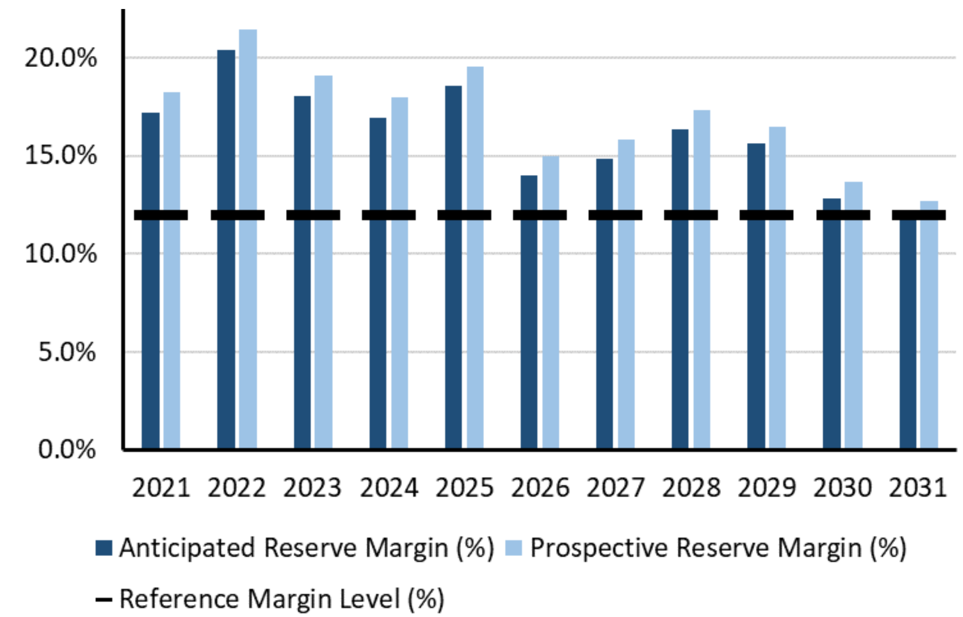
Transmission

Approved transmission projects increased since the last iteration of the MISO Transmission Expansion Plan reported in the *2020 LTRA*. Most of the current approved projects (60%) are needed as baseline reliability projects to maintain system reliability in accordance with NERC Reliability Standards. A quarter of the approved projects are for replacing aging equipment, and most of the remaining projects are generator interconnection projects for the integration of new resources.

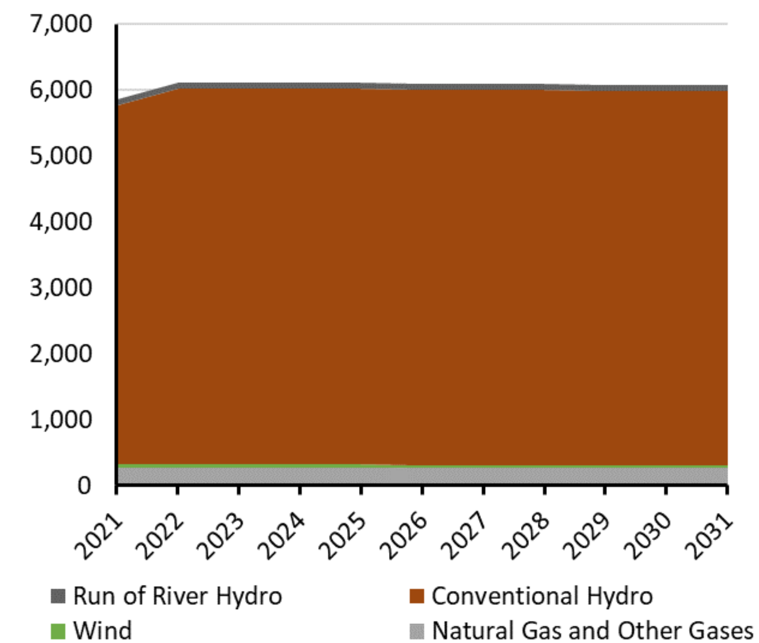
Reliability Issues

Effective dialogue among stakeholders will continue to be key to transformation—identifying needs and working with MISO to develop solutions that work across the footprint. As the MISO fleet continues to evolve, ongoing comprehensive analysis is needed to detail risks and inform change in MISO's planning, markets, and operations processes. MISO will leverage its resource adequacy construct and pricing enhancements as well as the forums where discussions are already underway on transmission planning to ensure needed changes are identified and enhancements made as demand for and production of electricity continues to develop.

Demand, Resources, and Reserve Margins (MW)										
Quantity	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Internal Demand	4,493	4,534	4,551	4,545	4,709	4,712	4,717	4,734	4,769	4,810
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,493	4,534	4,551	4,545	4,709	4,712	4,717	4,734	4,769	4,810
Additions: Tier 1	540	540	540	540	540	540	540	540	540	540
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-566	-622	-652	-587	-587	-542	-466	-471	-565	-565
Existing-Certain and Net Firm Transfers	4,869	4,814	4,784	4,848	4,827	4,872	4,948	4,934	4,841	4,841
Anticipated Reserve Margin (%)	20.4%	18.1%	17.0%	18.5%	14.0%	14.9%	16.4%	15.6%	12.8%	11.9%
Prospective Reserve Margin (%)	21.4%	19.1%	18.0%	19.6%	15.0%	15.9%	17.3%	16.5%	13.7%	12.7%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MRO-Manitoba Hydro ARM is above the Reference Margin Level throughout the assessment period.
- Three units of the seven-unit Keeyask hydro station are in service at the time of the LTRA publication, and the remaining units are expected to be operational prior to Summer 2022. When complete, the Keeyask hydro station is a 630 MW net addition to Manitoba Hydro's system.

MRO-Manitoba Hydro Fuel Composition (MW)										
Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Natural Gas	278	278	278	278	278	278	278	278	278	278
Wind	52	52	52	52	31	31	31	31	31	31
Conventional Hydro	5,690	5,690	5,690	5,690	5,690	5,690	5,690	5,676	5,676	5,676
Run of River Hydro	91	91	91	91	91	91	91	91	91	91
Total MW	6,110	6,110	6,110	6,110	6,090	6,090	6,090	6,076	6,076	6,076

MRO-Manitoba Hydro Assessment

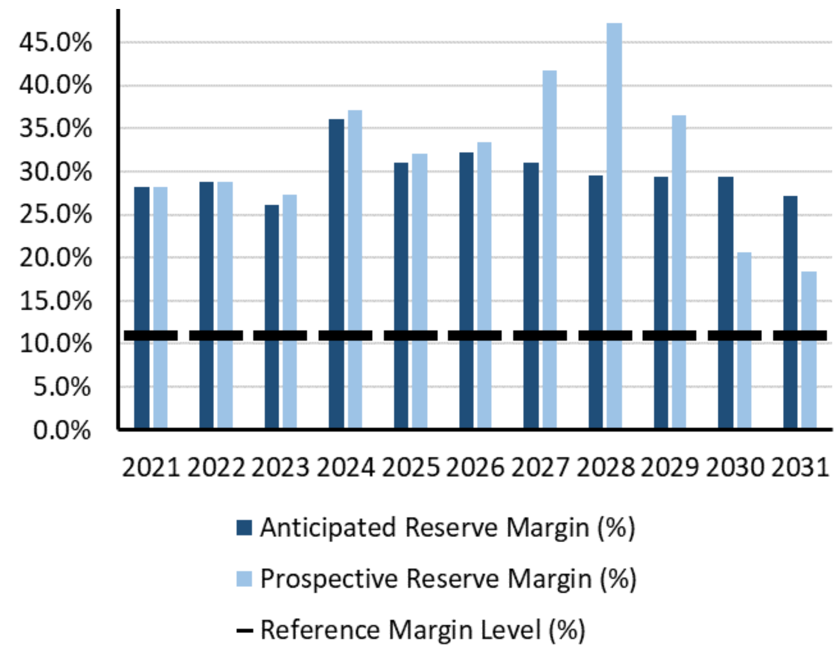
The ARM does not fall below the Reference Margin Level of 12% in the first five years of the assessment period. Three of the Keeyask hydro station units are in service, and this ARM analysis assumes that two additional units will come into service by the end of 2021. The completion of all seven units at the Keeyask hydro station is anticipated for the summer of 2022 and will help ensure resource adequacy in the remainder of the current assessment period. When complete, the Keeyask hydro station is a 630 MW net addition to Manitoba Hydro's system. No Tier 2 resources have been assumed to come into service during the assessment period. No resource adequacy issues are anticipated.

The 126 MW winter rating Selkirk natural gas generating station was retired April 1, 2021. The Selkirk station retirement decision was based on several factors, including a desire to reduce carbon emissions, the high operating costs of the station, increased transmission system reliability with the Bipole III high-voltage direct current (HVDC) line, additional supply being available from the Keeyask hydro station, and additional import capability with the Manitoba to Minnesota Transmission Project. No resource adequacy issues are anticipated as the ARM remains above the 12% Reference Margin.

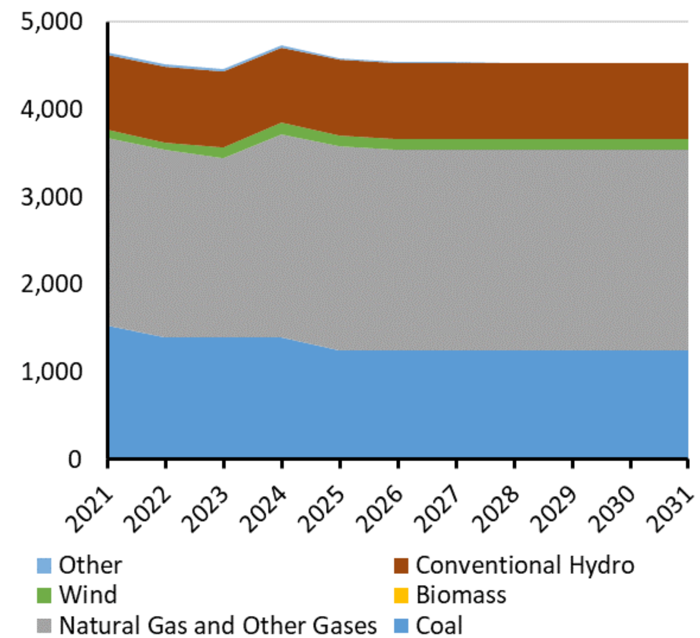
A capacity transfer of 190 MW from Manitoba to Saskatchewan beginning June 1, 2022, (increasing to 215 MW beginning June 1, 2024) will tend to increase east to west flow on the Manitoba–Saskatchewan interface. The 230 kV/390 MVA Birtle to Tantallon line, which will help facilitate this and other capacity transfers to Saskatchewan, was placed in service in March 2021. The Manitoba to Minnesota Transmission Project, a major new 500 kV interconnection, was placed into service on June 1, 2020 and provides for alternative supply from the MISO market during drought conditions and improves the resilience of Manitoba Hydro's system to extreme events, including drought.

Manitoba is not currently experiencing the large additions of wind and solar resources being seen in other areas, so emerging reliability issues from large wind and solar resource additions are not anticipated in the next five years. Additions of energy storage resources in the next ten years are not anticipated at this time. There is a potential for significant solar DER resources in the latter half of the assessment period and plans are being developed to study the impacts on the Manitoba Hydro system.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	3,732	3,744	3,695	3,718	3,741	3,722	3,751	3,758	3,792	3,815
Demand Response	63	63	63	63	63	63	63	63	63	63
Net Internal Demand	3,669	3,681	3,632	3,655	3,678	3,659	3,688	3,695	3,729	3,752
Additions: Tier 1	37	77	430	430	430	430	430	430	430	430
Additions: Tier 2	0	40	40	40	40	389	1,087	1,087	1,087	1,087
Additions: Tier 3	0	0	20	20	20	20	20	20	20	20
Net Firm Capacity Transfers	290	290	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,687	4,568	4,513	4,357	4,435	4,368	4,350	4,350	4,398	4,343
Anticipated Reserve Margin (%)	28.7%	26.2%	36.1%	31.0%	32.3%	31.1%	29.6%	29.3%	29.5%	27.2%
Prospective Reserve Margin (%)	28.7%	27.3%	37.2%	32.1%	33.3%	41.7%	47.2%	36.6%	20.6%	18.3%
Reference Margin Level (%)	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MRO-SaskPower's ARM is above the Reference Margin Level throughout the assessment period.
- SaskPower is adding approximately 750 MW of new generation within the next five years, including three wind generation facilities of combined 385 MW installed capacity and a 350 MW natural gas facility. Confirmed retirements in the area total approximately 550 MW.
- Saskatchewan is also adding a long-term firm capacity transfer from Manitoba of 190 MW in 2022. A new 230 kV tie line with Manitoba was placed in service in early 2021.

MRO-SaskPower Fuel Composition (MW)										
Fuel	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Coal	1,392	1,392	1,392	1,253	1,253	1,253	1,253	1,253	1,253	1,253
Natural Gas	2,148	2,053	2,328	2,328	2,288	2,288	2,288	2,288	2,288	2,288
Biomass	3	3	3	3	3	3	3	3	3	3
Wind	86	126	124	124	124	124	122	122	122	122
Conventional Hydro	862	862	862	862	862	862	862	862	862	862
Other	22	22	22	22	22	17	1	1	1	1
Total MW	4,511	4,456	4,729	4,590	4,550	4,545	4,527	4,527	4,527	4,527

MRO-SaskPower Assessment

Saskatchewan uses a criterion of 11% as the reference reserve margin and has assessed its PRM for the upcoming 10 years with the summer and winter peak hour loads, available existing and anticipated generating resources, firm capacity transfers, and available DR for each year. Saskatchewan's ARM ranges from approximately 26% to 40% and does not fall below the Reference Margin Level.

Saskatchewan's system peak forecast is contributed by econometric variables, weather normalization, and individual level forecasts for large industrial customers. Average annual summer and winter peak demand growth is expected to be approximately 0.5% with a range from -1.3% to 1.2% throughout the assessment period.

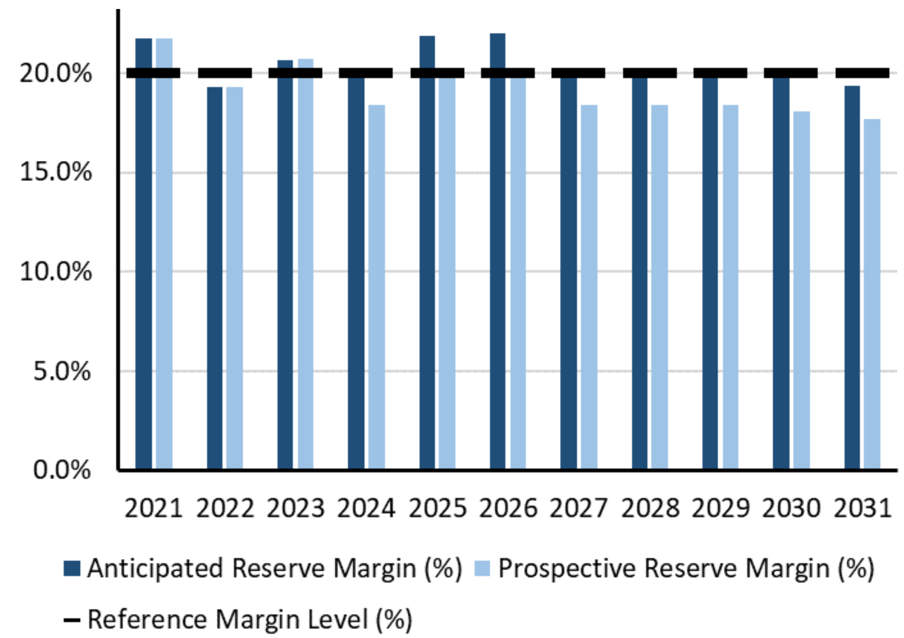
Saskatchewan is adding approximately 750 MW of Tier 1 generation within the next five years, including three wind generation facilities of combined 385 MW installed capacity and a 350 MW natural gas facility. Saskatchewan is also adding a long-term firm capacity transfer from Manitoba of 190 MW in 2022. Under Tier 2, over 1000 MWs of new generation is projected in the assessment period, including solar facility and three natural gas facilities. Under Tier 3, approximately 20 MWs of generation is projected. A total of approximately 559 MW is confirmed for retirements; this includes 278 MW of coal generation, 213 MW of natural gas, a 21 MW heat recovery facility, 22 MW of wind facilities, and 25 MW of hydro import contract. Unconfirmed retirements of over 1,400 MW is also expected in the assessment period. This includes approximately 1,200 MW of coal generation that will be phased out by the end of 2029. Generating resources being planned as Tier 2 and Tier 3 will replace the retired units before they retire, so Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

Saskatchewan's EE and energy conservation programs include incentive-based and education programs that focus on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy and demand reductions during peak hours. Energy provided from EE and DSM programs are modeled as load modifiers and are netted from both the peak load and energy forecasts. A steady growth is expected in EE and conservation over the assessment period. Saskatchewan's DR program has contracts in place with industrial customers for interruptible load based on defined DR programs. The first of these programs provides a curtailable load, currently up to 63 MW, with a 12-minute event response time. Other programs are also in place that provide access to additional curtailable load that requires up to two hours notification time.

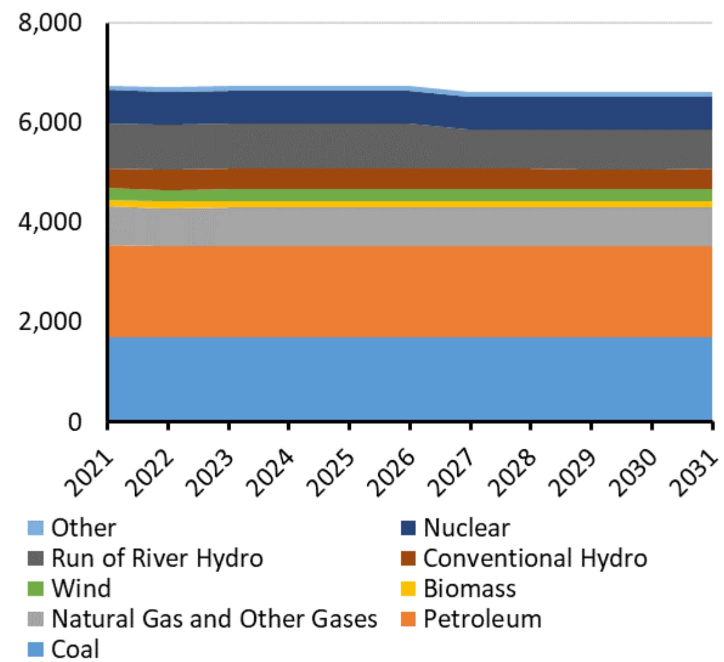
A new 230 kV tie line with Manitoba was placed in service in early 2021 to enable new capacity transfers between the two areas. Approximately 80 km of 230 kV transmission line is under the planning phase and several other transmission projects (approximately 300 circuit km) are under conceptual phase in the 5–10 year planning horizon. These projects are driven by load growth, new generation additions, and reliability needs.

MRO-SaskPower performs transmission planning studies that include the annual assessment according to NERC standard TPL-001-4, Transmission System Planning Performance Requirements and other applicable periodic assessments to meet NERC requirements, system impact for new load/generation interconnections, generation retirements, transmission service request, area adequacy, and other special studies as required to identify potential system issues. Mitigations are identified as part of these studies and included in the system development plan to ensure system performance requirements are met.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	5,727	5,759	5,788	5,786	5,780	5,776	5,774	5,772	5,786	5,806
Demand Response	310	321	340	344	343	343	342	341	341	340
Net Internal Demand	5,418	5,438	5,448	5,442	5,437	5,433	5,432	5,430	5,446	5,466
Additions: Tier 1	3	26	27	27	27	29	29	29	29	29
Additions: Tier 2	0	5	5	5	5	5	5	5	5	5
Additions: Tier 3	19	19	19	219	219	219	219	359	359	359
Net Firm Capacity Transfers	-149	-72	-90	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	6,459	6,533	6,515	6,605	6,605	6,495	6,495	6,493	6,493	6,496
Anticipated Reserve Margin (%)	19.3%	20.6%	20.1%	21.9%	22.0%	20.1%	20.1%	20.1%	19.8%	19.4%
Prospective Reserve Margin (%)	19.3%	20.7%	18.4%	20.2%	20.3%	18.4%	18.4%	18.4%	18.1%	17.7%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- There is a forecast of 0.2% compound annual growth rate in demand over the duration of the LTRA analysis period.
- The Maritimes Link, an undersea HVDC undersea cable connection to the Canadian province of Newfoundland and Labrador, began service in late 2017. This cable connection will allow for the retirement of a 150 MW coal-fired generator in late 2021 with an equivalent amount of firm hydro capacity imported through the cable so that the overall resource adequacy is unaffected.

NPCC-Maritimes Fuel Composition (MW)										
Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695
Petroleum	1,829	1,843	1,843	1,843	1,843	1,843	1,843	1,841	1,841	1,841
Natural Gas	760	760	760	760	760	760	760	760	760	760
Biomass	134	134	134	134	134	134	134	134	134	134
Wind	236	241	241	241	241	241	241	241	241	241
Conventional Hydro	402	402	402	402	402	402	402	402	402	405
Run of River Hydro	905	906	907	907	907	798	798	798	798	798
Nuclear	660	660	660	660	660	660	660	660	660	660
Other	90	90	90	90	90	90	90	90	90	90
Total MW	6,711	6,731	6,732	6,732	6,732	6,624	6,624	6,622	6,622	6,625

NPCC-Maritimes Assessment

Planning Reserve Margins

The reference reserve margin level used for the NPCC-Maritimes is 20%. The ARM ranges from 19.4–21.9% during the ten years of this LTRA. The ARM is very close to the 20% reserve margin target level.

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole NPCC-Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of New Brunswick (NB) and Nova Scotia (NS), which are historically highly coincidental (typically between 97% and 99%). Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period. Peak loads are expected to increase by 4.4% during summer and by 1.8% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.4% in summer and 0.2% in winter. Annual energy forecasts are expected to increase by a total of 1.7% during the 10-year assessment period for an average growth of 0.2% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs by using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway, but no specific annual demand and energy saving targets currently exist.[56] During the 10-year LTRA assessment period, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 22 MW to 186 MW while the annual amounts for winter peak demand reductions rise from 92 MW to 530 MW.[56]

Distributed Energy Resources

The DER installed capacity in NS is approximately 200 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff, and BTM solar. Based on an LOLE analysis, the existing wind resources are assumed to have an effective load carrying capability of 19%, and BTM solar is assumed to have an ELCC of 0%. NS has shown embedded BTM solar PV projections of 19 MW in 2021 rising to 175 MW by 2031. These projects include distributed small-scale solar (mainly rooftop) that fall under NS Power's net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives, including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of NS Power's system peak (winter evenings). Prince Edward Island has shown an increase of embedded BTM solar PV projections of 7 MW in 2021 rising to 18 MW by 2031 with higher interest due to new provincial subsidies. The planned DER capacity in NB is 2.8 MW, starting in 2021–2022. NB has no future projections to report but does anticipate that DERs could increase rapidly over the next ten years and potentially impact operation of the distribution system in particular. Since the amount of DER resources that will be allowed to operate on the system is unknown at this time, NB (New Brunswick) Power does not forecast specific DER amounts and all such resources are included as EE and conservation for LTRA purposes.

Generation

The Maritimes area is not installing any new generation capacity for the purpose of mitigating resource adequacy issues. There are no new confirmed retirements in this *2021 LTRA* as compared to the *2020 LTRA*.

NB Power's 2020 Integrated Resource Plan assumes extending 28 MW diesel-fired generator and 290 MW of natural-gas-fired resource starting 2025 and 2026 respectively. These resources were included under unconfirmed retirements in the *2020 LTRA* but are extended in this *2021 LTRA*. In NB, there is a reduction of 20 MW in community-based wind projects, totaling the community-owned wind projects to 58 MW name plate capacity by 2022–2023. In NB, unconfirmed retirements include a hydro facility of 4 MW at the end of its service life that depends on regulatory approval and a 98 MW power purchase agreement contract.

In NS, Tier 1 resources include tidal projects with a total installed capacity of 32 MW expected to be phased in over the 10-year study period. NS Power completed an integrated resource plan in 2020 and developed an integrated resource plan (IRP) reference plan. However, the specific type, quantity, and timing of future resource additions and retirements in the Reference Plan remain uncertain. As a result, the changes in the Reference Plan have been included as Tier 3 resources in the assessment. These Tier 3 resources include natural gas additions of approximately 10 MW in 2023 and 150 MW in 2026 and 100 MW in 2030, including mainly combustion turbines and a small reciprocating engine.

[5656] Current and projected EE effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

Additional Tier 3 resources include a 10 MW battery in 2023 and new wind generation with a nameplate capacity of 400 MW in 2030. As per the IRP reference plan, these resource additions along with potential firm capacity imports could facilitate the retirement of approximately 320 MW of coal-fired generation and 170 MW of natural-gas-fired generation within the assessment period. However, these imports and retirements have not been included in the assessment due to their uncertainty.

Small amounts of new solar generation capacity (Tier 2) of up to 31 MW are expected to be installed in PEI during the 2022–2023 time frame. PEI also plans to add new 50 MW of thermal capacity (Tier 3) during the year 2026. The Northern Maine Independent System Administrator, which is part of the NB BA, projects new solar additions (Tier 1–3) of approximately 117 MW nameplate during this LTRA study period. NB derates its wind capacity by using a calculated year-round equivalent capacity of 22%. NS and PEI derate wind capacity to 19% and 15% of nameplate based on year-round calculated equivalent load carrying capacities for their respective individual sub-areas, respectively. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes area peak occurs either before sunrise or after sunset in the winter.

Energy Storage

NS Power includes a relatively small 10 MW battery added as a Tier 3 resource in 2023. Pilot projects and internal studies are underway to further understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks. These analyses are in a very preliminary stage. The value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. These studies will be evaluated further as the economics around these options become viable.

Capacity Transfers

Probabilistic studies show that the Maritimes area is not reliant on interarea capacity transfers to meet NPCC resource adequacy criteria.

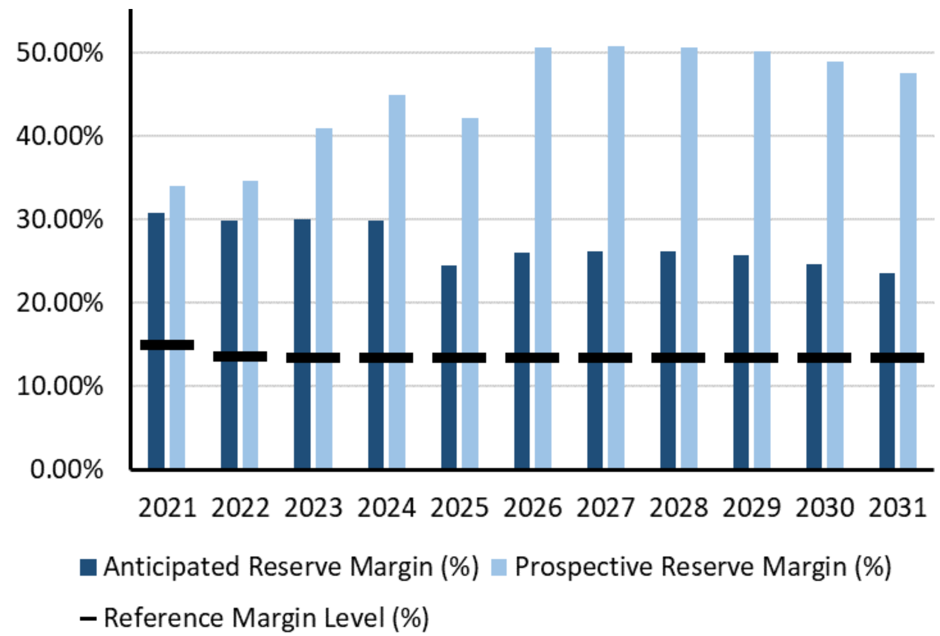
Transmission

Construction of a 475 MW +/- 200 kV high voltage direct current undersea cable link (Maritime Link) between Newfoundland and Labrador and NS was completed in late 2017. This cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, is expected to facilitate the unconfirmed retirement of a 150 MW (nameplate) coal-fired unit in NS in late 2021. This unit will only be retired once a similarly sized replacement firm capacity contract from Muskrat Falls is in operation so that the overall resource adequacy is unaffected by these changes. The Maritime Link could also potentially provide a source for imports from NS into NB that would reduce transmission loading in the Southeastern NB area.

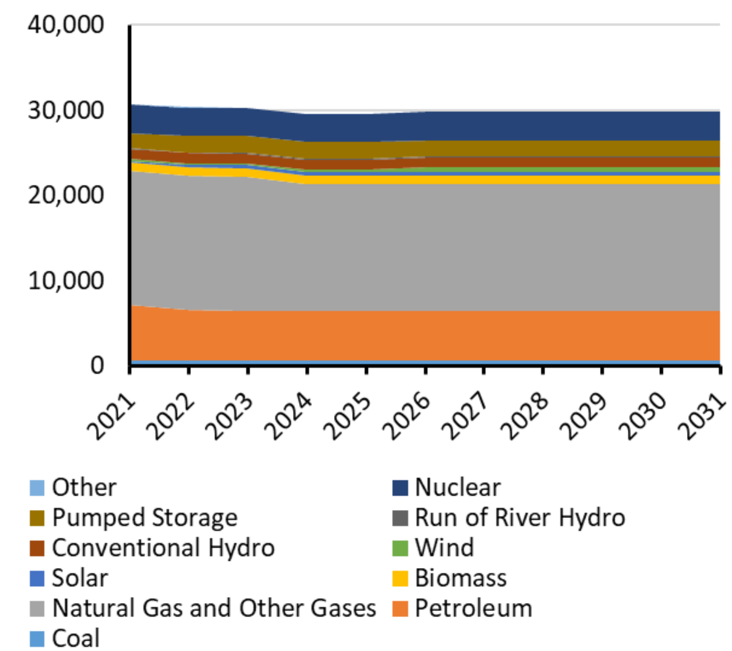
Reliability Issues

There are no known unique resource adequacy issues that affect reliability. The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual fuel oil/natural gas, tie benefits, and biomass with no one type feeding more than about 27% of the total capacity in the area. There is not a high degree of reliance upon any one type or source of fuel. The Maritimes area does not anticipate fuel disruptions that pose significant challenges to resource adequacy during the assessment period. This resource diversification also provides flexibility to respond to any future environmental issues, such as potential restrictions to greenhouse gas emissions.

Demand, Resources, and Reserve Margins (MW)										
Quantity	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Internal Demand	24,789	24,713	24,672	24,552	24,479	24,458	24,491	24,574	24,796	25,020
Demand Response	682	584	678	678	678	678	678	678	678	678
Net Internal Demand	24,107	24,129	23,994	23,874	23,801	23,780	23,813	23,896	24,118	24,342
Additions: Tier 1	87	280	1,147	1,147	1,147	1,373	1,373	1,373	1,373	1,373
Additions: Tier 2	330	1,866	2,798	3,398	5,050	5,050	5,050	5,050	5,050	5,050
Additions: Tier 3	1,456	2,480	3,435	4,914	5,286	5,427	7,513	7,513	7,513	7,513
Net Firm Capacity Transfers	1,292	1,059	1,487	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	31,152	31,090	30,029	28,597	28,633	28,655	28,669	28,682	28,693	28,706
Anticipated Reserve Margin (%)	29.9%	30.0%	29.9%	24.6%	26.1%	26.3%	26.2%	25.8%	24.7%	23.6%
Prospective Reserve Margin (%)	34.7%	41.0%	44.9%	42.2%	50.6%	50.9%	50.7%	50.2%	48.9%	47.6%
Reference Margin Level (%)	13.6%	13.4%	13.5%	13.5%	13.5%	13.5%	13.5%	13.5%	13.5%	13.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- NPCC-New England is forecast to have the resource base and transmission system needed to meet consumer demand for power through the 10-year LTRA assessment period.
- NPCC-New England is currently energy constrained during periods of peak winter weather, posing the greatest reliability risk in the area. Challenges to meeting winter electricity demands have the potential to extend into all seasons in the longer-term horizon as the resource mix evolves. Energy security and reliability issues may arise from energy production limitations associated with non-firm fuel sources, VERs (i.e., wind and solar PV), environmental regulation compliance, and natural gas and fuel oil availability during winter. New England state policies and incentives for developing renewable resources as well as energy efficiency and electricity imports from neighboring areas are helping offset the area's dependence on natural gas for electric reliability.
- The future reliable and economic performance of the power system is expected to continue to improve as a result of approximately $1.3 billion of planned BPS transmission upgrades over the next 10 years, much of which is still in the siting process or under construction. Generator retirements, the integration of many DERs and grid-level VERs, the use of inverter-based technologies, and issues rising from minimum-load assessments and high-voltage conditions are changing the needs for traditional reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy.
- The overall system is transforming to a cleaner, hybrid grid—with low emissions and the widespread development of renewable resources. Over the longer-term planning horizon, additional imports of Canadian hydro-electricity and new technologies, such as smart meters, micro-grids, and energy storage, will likely continue the trend toward a cleaner, albeit more complex, power system. ISO-NE closely monitors regional policy developments, which include the electrification of the transportation sector as well as the residential sector with heat-pumps that will increase demand beyond the traditional 10-year LTRA forecast period.

NPCC-New England Fuel Composition (MW)										
Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	607	607	607	607	607	607	607	607	607	607
Petroleum	5,984	5,835	5,790	5,790	5,790	5,790	5,790	5,790	5,790	5,790
Natural Gas	15,768	15,768	14,935	14,935	14,935	14,935	14,935	14,935	14,935	14,935
Biomass	986	986	979	979	979	979	979	979	979	979
Solar	268	374	414	414	414	414	414	414	414	414
Wind	182	184	340	340	567	567	567	567	567	567
Conventional Hydro	1,155	1,155	1,155	1,155	1,155	1,155	1,155	1,155	1,155	1,155
Run of River Hydro	137	137	137	137	137	137	137	137	137	137
Pumped Storage	1,892	1,892	1,892	1,892	1,892	1,892	1,892	1,892	1,892	1,892
Nuclear	3,318	3,318	3,318	3,318	3,318	3,318	3,318	3,318	3,318	3,318
Other	44	44	44	44	44	44	44	44	44	44
Total MW	30,339	30,301	29,610	29,610	29,837	29,837	29,837	29,837	29,837	29,837

NPCC-New England Assessment

Planning Reserve Margins
ISO-NE's Reference Margin Level is based on the capacity needed to meet the NPCC one day in 10 years LOLE resource planning reliability criterion. The capacity needed, referred to as the installed capacity requirement, varies from year-to-year depending on projected system conditions (e.g., demand, generation, emergency assistance assumed available from the interconnection, capacity imports, etc.). The installed capacity requirement is calculated on an annual basis, covering four years into the future. The latest calculations result in a Reference Margin Level of 13.6% in 2022, 13.4% in 2023, and 13.5% in 2024 as expressed in terms of the 50/50 peak demand forecast published in May 2021. In this assessment, the last calculated Reference Margin Level (13.5%) is applied for the remaining seven years of the LTRA forecast. ISO-NE's ARM, ranging from a low of 23.6% in Summer 2031 to a high of 77.6% in the winter of 2022/2023 is expected to stay above the Reference Margin Level during the assessment period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments
Revisions to the ISO planning processes now reflect FERC Order 1000 requirements, probabilistic study assumptions, and changes to national and regional criteria. Coordinated planning activities with other systems will continue growing, particularly to provide access to a greater diversity of resources (including hydro imports and VERs) and to meet environmental compliance obligations.

Demand
Forecasts of the regional net peak and annual energy show either zero or negative growth from the additions of solar PV and EE along with other BTM resources that are reflected in the planning processes. Thus, growth of net peak demand is not a key driver of new infrastructure needs over the 10-year planning horizon. Longer term, the electrification of transportation and heating/cooling load is expected to increase system loads.

Demand Side Management
Currently, approximately 587 MW of dispatchable DR participates in the energy and reserve markets in addition to the forward capacity market (FCM). Regional DR will increase to 678 MW by 2024, and this value is assumed constant/available through the remainder of the assessment period.

Distributed Energy Resources
New England has 178 MW (1,486 MW nameplate) of wind generation and 836 MW (2,594 MW nameplate) of BTM solar PV. Approximately 225 MW (nameplate) of on-shore wind generation projects and 3,800 MW (nameplate) of solar PV projects have requested generation interconnection studies. BTM solar PV is forecast to grow to 1,098 MW (5,467 MW nameplate) by 2031. The BTM solar PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing solar PV production at the time of the system (summer) peak as increasing solar PV penetrations shift the timing of peaks later in the day, a decrease from 32.2% of nameplate in 2021 to about 20% in 2031.

Generation
Needed capacity and operating reserves are procured through the wholesale markets. Studies of expected system conditions show that developing new resources near load centers, particularly in the geographical areas of Northeast Massachusetts (NEMA)/Boston and Southeast Massachusetts (SEMA)/Rhode Island would provide the greatest reliability benefit. To the extent well-sized and well-placed cost-effective resources were developed to more closely match demand, the system would perform more reliably, require fewer transmission upgrades, and exhibit less congestion and losses.

The regional reliance on natural-gas-fired generation coupled with the non-firm contracting by generators for fuel transport and uncertain LNG deliveries can pose reliability issues any time of the year. ISO-NE and interregional organizations have assessed these risks in a number of energy-security studies, and ISO-NE has taken a number of actions to improve the overall reliable and economical operation of the system. The greater development of renewable resources (particularly those with energy storage), EE, imports from neighboring areas, and continued investment in natural gas efficiency measures are also part of the solution.

Future environmental regulations, public policies, and economic considerations will affect the operation of existing resources and new resources. Existing oil- and coal-fired generators are expected to retire and be replaced with more efficient natural-gas-fired generation and renewable resources. Generator environmental compliance depends on final federal regulations and site-specific circumstances that have been subject to uncertainty and delays that could affect generator permitting and operations. Federal and state policies and initiatives will continue to affect the planning process, such as those promoting EE, solar PV, and wind resources. Carbon-emission targets will likely be the key regional environmental constraint on energy production by fossil-fired generating units.

ISO-NE, with stakeholder input, is working on near- and long-term market improvements to expand delivery of firm energy and ancillary services that will cost-effectively address energy production uncertainties, fuel supply limitations, variability in renewable resource output, and enhance energy-security.

Energy Storage

ISO-NE currently has 61 MW of battery storage resources with an additional 600 MW expected to be in-service by June 1, 2024. There are approximately 4,400 MW of Tier 2 and 3 stand-alone battery projects currently in the queue, of which a portion will go commercial by 2025. Another 550 MW of projects in the queue are co-located, primarily with solar PV resources.

Capacity Transfers

NPCC-New England is interconnected with the three BAs of NPCC-Québec, NPCC-Maritimes, and NPCC-New York. ISO-NE takes into account the transfer capability with these BAs to assure that their limits are reflected in the regional resource adequacy reviews. ISO-NE's FCM methodology limits the purchase of import capacity based on the interconnection transfer limits. ISO-NE's capacity imports are assumed to range from 1,059 MW to 1,487 MW during the 2022–2024 summer period. Since that is the extent of the period of the FCM supply obligations and no assumptions are made regarding the availability of imports after that time, the ISO has assigned capacity import and export values of zero to the remainder of the LTRA years.

Transmission

Transmission expansion in NPCC-New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of IBRs, and changes to mandatory planning criteria promulgated by NERC and NPCC will likely drive the longer-term need for transmission projects.

Reliability Issues

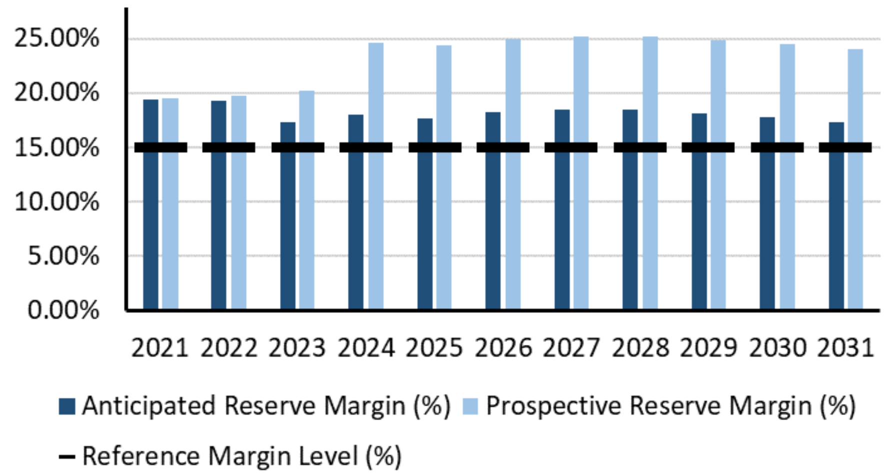
NCPP-New England's bulk electric power grid is transforming to a sustainable, hybrid grid that supports the connection of more renewable energy and the transition to the smart grid, which will allow for the more effective use of DERs. The widespread addition of IBR technologies and DERs will require transmission (bulk and distribution level) upgrades and control system improvements for reliably interconnecting these resources to the electric grid. Structural changes to the existing transmission and distribution systems are being analyzed and implemented, and new planning and operating procedures are being put in place to help transform the grid and improve the reliable, economical, and environmental performance of the overall power delivery system.

The lack of observability and controllability of VERs and DERs will need to be addressed to realize the full benefits of energy storage, micro-grids, and smart grid technologies. The rapid implementation of revised interconnection standards for distributed resources, including the IEEE 1547 and testing standards, is vital for ensuring overall system reliability and facilitating the economic development of renewable resources, such as solar PV. ISO-NE remains a leader in technological innovation as shown by the widespread use of phasor measurement units, extensive application of flexible alternating-current transmission systems, and the implementation of state-of-the-art forecasting methods for wind resources and solar PV.

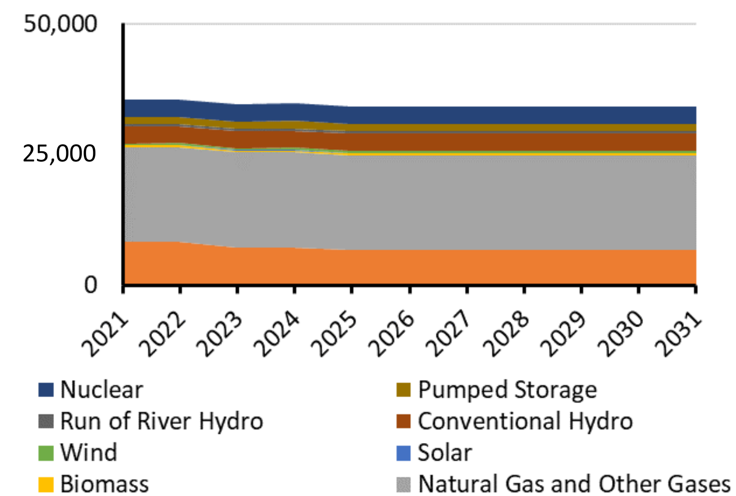
Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	32,178	31,910	31,641	31,470	31,326	31,278	31,284	31,348	31,453	31,565
Demand Response	822	822	822	822	822	822	822	822	822	822
Net Internal Demand	31,356	31,088	30,819	30,648	30,504	30,456	30,462	30,526	30,631	30,743
Additions: Tier 1	86	138	186	186	186	186	186	186	186	186
Additions: Tier 2	129	891	2,050	2,050	2,050	2,050	2,050	2,050	2,050	2,050
Additions: Tier 3	2,387	5,218	8,165	8,979	9,634	9,634	9,634	9,634	9,634	9,634
Net Firm Capacity Transfers	1,811	1,795	1,618	1,952	1,952	1,952	1,952	1,952	1,952	1,952
Existing-Certain and Net Firm Transfers	37,325	36,342	36,164	35,885	35,885	35,885	35,885	35,885	35,885	35,885
Anticipated Reserve Margin (%)*	19.31%	17.35%	17.95%	17.70%	18.25%	18.44%	18.41%	18.17%	17.76%	17.33%
Prospective Reserve Margin (%)	19.72%	20.21%	24.60%	24.38%	24.97%	25.17%	25.14%	24.88%	24.45%	24.00%
Reference Margin Level (%)**	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%

*Wind, solar and run-of river summer-certain capacities are derated by 84%, 60% and 57%, respectively, for the summer Capability Period.

*** The NERC LTRA Reference Margin Level is 15% and is used for the sole purpose of the LTRA; however, there is no planning reserve margin criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2021–2022 IRM at 20.7%. All values in the IRM calculation are based upon full Installed Capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.*



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Clean energy policies, such as the Climate Leadership and Community Protection Act (CLCPA), are reshaping the New York grid in unprecedented ways. New York's electric industry is transforming from a grid that is powered by traditional synchronous, controllable generation to more non-emitting, weather-dependent intermittent resources and distributed generation. The increase in the intermittent and distributed generation, along with the related penetration of inverter-based technology, create new challenges. Additionally, clean energy production is a key underlying element of electrification policies. New York is projected to become winter peaking in future decades due to electrification, primarily via heat pumps and electric vehicles.
- Wholesale markets, operations, and planning are continuing to evolve to provide the economic signals necessary to reflect system needs and to incent resources capable of resolving those needs. With high penetration of renewable intermittent resources, dispatchable, emissions-free, and long-duration resources are needed to balance intermittent supply with demand. These types of resources have sufficient capacity and possess attributes that have the ability to come on-line quickly, stay on-line as needed, maintain system balance and stability, and adapt to meet rapid, steep ramping needs.
- New York State Department of Environmental Conservation adopted a regulation to limit nitrogen oxides emissions from simple-cycle combustion turbines (Peaking Units) referred to as the "Peaker Rule." The Peaker Rule required all impacted plant owners to file compliance plans by March 2, 2020. The *Reliability Needs Assessment* and the *Short Term Assessment of Reliability* reflect those compliance plans in the study assumptions.
- The forecasted ten-year annual average energy growth rate is lower than last year. The forecasted ten-year annual average summer peak demand growth rate is also lower than last year. The forecasted decrease in energy usage can be attributed in part to the impacts of COVID-19 reductions on load, increasing impacts of energy efficiency initiatives, and increasing amounts of BTM solar generation. The impact of BTM generation is significant in the first five years of the forecast. Load-increasing impacts occur due to electric vehicle usage and other electrification (i.e., conversion of home heating, cooking, water heating, and other end-uses moving away from fossil-fuel based systems to electric systems). The relative impact of the behind-the-meter solar on peak declines over time as the New York summer peak is expected to shift further into the evening. New York is projected to become winter peaking in future decades due to electrification primarily via heat pumps and electric vehicles.

NPCC-New York Fuel Composition (MW)

Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Petroleum*	8,229	7,269	7,269	6,682	6,682	6,682	6,682	6,682	6,682	6,682
Natural Gas*	18,196	18,188	18,188	18,162	18,162	18,162	18,162	18,162	18,162	18,162
Biomass	322	322	322	322	322	322	322	322	322	322
Solar	46	46	54	54	54	54	54	54	54	54
Wind	339	391	430	430	430	430	430	430	430	430
Conventional Hydro	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313	3,313
Run of River Hydro	407	407	407	407	407	407	407	407	407	407
Pumped Storage	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Nuclear	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342
Total MW	35,600	34,685	34,732	34,119	34,119	34,119	34,119	34,119	34,119	34,119

*Most petroleum and natural-gas-fired generation in NPCC-New York assessment area is capable of operating using either fuel (i.e., dual-fueled units). For purposes of this table, generators are assigned to the category that corresponds to their primary fuel.

NPCC-New York Assessment

Planning Reserve Margins: The LTRA Reference Margin Level, determined as per NERC definition, is 15%; however, there is no PRM criterion in New York. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. The NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 days/year probability of unplanned load loss. The NYISO also provides significant support to the New York State Reliability Council (NYSRC), which conducts an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC resource adequacy criterion. The IRM for the 2021–2022 capability year is 20.7% of the forecasted New York Control Area peak load. Note that all values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 20.7%. Additionally, the NYISO performs an annual study to identify the locational minimum installed capacity requirements (LCRs) for the upcoming capability year. In 2018, FERC accepted proposed revisions for determining LCRs: the new methodology utilizes an economic optimization algorithm to minimize the total cost of capacity for the New York Balancing Area (NYBA). The NYISO establishes statewide and ICAP requirements for the LSEs.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments: The Climate Leadership and Community Protection Act targets include 85% reduction in greenhouse gas emissions by 2050, 100% carbon-dioxide-free electricity by 2040, 70% renewable energy by 2030, 9,000 MW of offshore wind by 2035, 3,000 MW of energy storage by 2030, 6,000 MW of solar PV by 2025, and 22 million tons of carbon dioxide reduction through energy-efficiency and electrification. With high penetration of renewable intermittent resources, dispatchable, emissions-free, and long-duration resources are needed to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes like the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs.

Demand: The energy and peak load forecasts are based upon end-use models that incorporate forecasts of economic drivers and end-use technology efficiency and saturation trends. The impacts of EE and technology trends are largely incorporated directly into the forecast model with additional adjustments for policy-driven EE impacts made where needed. The expected impacts of DERs, electric vehicles, other electrification, energy storage, and BTM solar PV are exogenous to the model. The forecast of BTM solar PV-related reductions in summer peak assumes that the NPCC-New York peak currently occurs at 4:00 p.m. or 5:00 p.m. Eastern in July or August. The hour of the summer peak varies and is assumed to shift slightly later into the evening over the forecast horizon. The forecast of BTM solar PV-related reductions to the winter peak is zero because the sun sets before the assumed peak hour of 6:00 p.m. Eastern in January. The baseline forecast includes upward adjustments for increased usage of electric vehicles and other electrification and downward adjustments for the impacts of EE trends and DERs, including BTM energy storage and BTM solar PV. The impacts of net electricity consumption of all energy storage units are added to the baseline energy forecast while the peak-reducing impacts of BTM energy storage units are deducted from the baseline peak forecasts. The relative BTM solar impact on peak declines over time as the NYBA summer peak is expected to shift further into the evening. New York is projected to become winter peaking in future decades due to electrification primarily via heat pumps and electric vehicles.

The economic and behavioral changes stemming from the COVID-19 pandemic caused large differences in 2020 load levels and load shapes relative to a typical year. Weather-normalized annual energy usage across the NYBA was more than 4,000 GWh (2.6%) below the pre-COVID baseline forecast developed in early 2020. The largest impacts were seen in April and May during the height of the initial lockdown period with usage across the NYCA more than 8% below expected. These effects tapered off into the summer and fall with smaller deviations relative to expected. The largest load reductions have consistently been in New York City (Zone J), being an urban area with a large share of commercial load.

Demand-Side Management: The NYISO's resource planning process accounts for DR resources that participate in the NYISO's reliability-based DR programs based on the enrolled MW derated by historical performance. The NYISO will develop market concepts to encourage the participation of flexible load, which will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increases in response to the state's climate and clean energy policies.

Distributed Energy Resources: The NYISO is currently implementing a three- to five-year plan to integrate DERs, including DR resources, into its energy, capacity, and ancillary services markets. The NYISO published a DER roadmap document in February 2017 that outlined the NYISO's vision for DER market integration. FERC approved the NYISO's proposed tariff changes in January 2020. The NYISO is currently identifying the related software and procedure changes and is targeting implementation in Q4 2022. The DER Participation Model project aims to enhance participation of DERs in competitive wholesale markets. These measures closely align the bidding and performance measurements for DER with the rules for generators and establish a state of the art model that is largely consistent with the market design envisioned by FERC in its Order No. 2222.

Generation: The NYISO's *2020 Reliability Needs Assessment* (*2020 RNA)* included approximately 680 MW of proposed generation, mostly wind-powered. The 680 MW Valley Energy Center entered into service in 2018, and the 1,020 MW Cricket Valley Energy Center entered into service in 2020. Indian Point Unit 2 deactivated in 2020, and Indian Point Unit 3 deactivated in 2021. The New York State Department of Environmental Conservation adopted a regulation to limit nitrogen oxide emissions from simple-cycle combustion turbines, also known as peaking units (referred to as the "Peaker Rule"). The Peaker Rule, which phases in compliance obligations between 2023 and 2025, will affect approximately 3,300 MW of simple-cycle turbines located mainly in the lower Hudson Valley, New York City, and Long Island. The rule required affected unit owners to submit compliance plans to the New York State Department of Environmental Conservation by March 2020. The compliance plans indicated that approximately 1,500 MW of capacity will be unavailable during the summer of 2025. Approximately 800 MW of those generators will be unavailable in 2023. The majority of the generators are located in the New York City area. Importantly, the Peaker Rule allows the NYISO to designate resources that are needed to sustain reliability on the grid to continue operation on a temporary basis beyond 2023 and 2025 until alternative reliability solutions can be implemented. The *2020 RNA* Base Case reflects generator compliance plans.

New York's electric industry is transforming from a grid that is powered by traditional synchronous, controllable generation to more non-emitting, weather-dependent intermittent resources and distributed generation. Market enhancements are underway to meet these challenges. Market rules that incentivize investment in resources that can respond rapidly to changing conditions will be essential for maintaining reliability of the grid of the future. New market rules are underway for energy storage integration, participation in our wholesale electricity markets by DER, and new ancillary services products that will support a more dynamic grid. Additionally, the NYISO is developing new market rules for capacity markets.

Energy Storage: Battery storage resources help to fill in voids created by reduced output from VERs, but sustained periods of reduced generation can rapidly deplete battery storage capabilities. The NYISO worked with its stakeholders throughout 2020 to develop the Hybrid Co-Located Model. The NYISO plans on making this market model available to developers in late 2021. Additionally, the NYISO is working with its stakeholders throughout 2021 to further develop a method for hybrid resource participation in the wholesale markets. This ongoing work will support policy efforts to integrate more clean energy resources into the grid. Additionally, the resource adequacy simulation tools used in planning and also for setting the IRM were enhanced to include energy limited resources models that allow for charging and discharging as well as temporal constraints (i.e., hours/days or hours/month).

Capacity Transfers: The models used for the NYISO planning studies include the firm capacity transactions (purchases and sales) with the neighboring systems as a Base Case assumption.

Transmission: The 2020–2021 reliability planning process includes proposed transmission projects and transmission owner local transmission plans that have met the reliability planning inclusion rules. The *2020 RNA* identified transmission security criteria violations as well as resource adequacy violations. The reliability planning process allows for subsequent updates, and three projects in the ConEdison area are now included in the post-RNA assumptions along with updated load forecasts. With these updates, there are no remaining bulk power transmission facilities reliability needs in the 2020–2021 reliability planning cycle. Additionally, the NYISO board of directors has selected public policy transmission Projects, one for Western New York and a second set of two projects for central New York and the Hudson Valley that together address what is known as the AC Transmission Need. When completed, these projects will add more transfer capability in Western NY and between Upstate and Downstate New York. New York's grid is evolving to meet the state's 2030 and 2040 clean energy objectives.

The Climate Leadership and Community Protection Act enacted in 2019 requires an economy-wide approach to addressing climate change and decarbonization. Included are mandates to deliver 70% of New York energy from renewable resources by 2030 and 100% emissions-free electricity supply by 2040 while promoting electrification in other sectors of the economy. While the NYISO has two public policy projects that have been selected to address constraints on the system, additional transmission is needed to meet these targets.

On March 18, 2021, the Public Service Commission issued an order finding that the Community Protection Act constitutes a public policy requirement that drives the need for the following:

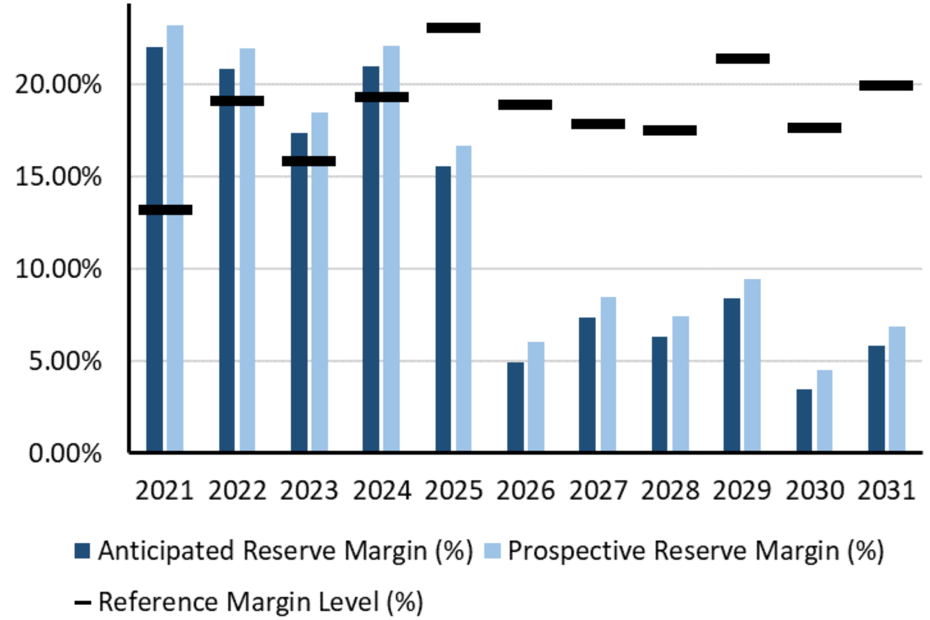
- Adding at least one bulk transmission intertie cable to increase the export capability of the LIPA-Con Edison interface, which connects NYISO's Zone K to Zones I and J, to ensure that the full output from at least 3,000 MW of offshore wind is deliverable from Long Island to the rest of the state
- Upgrading associated local transmission facilities to accompany the expansion of the proposed offshore export capability

As a result, a new Public Policy Transmission Planning Process is in progress. The NYISO solicited solutions to meet the Long Island Export Public Policy Transmission Need following a baseline analysis and an associated technical conference for prospective developers. The NYISO will evaluate proposed solutions for viability and sufficiency to meet the need and may select the more efficient or cost-effective transmission solution to meet the Public Policy Transmission Need.

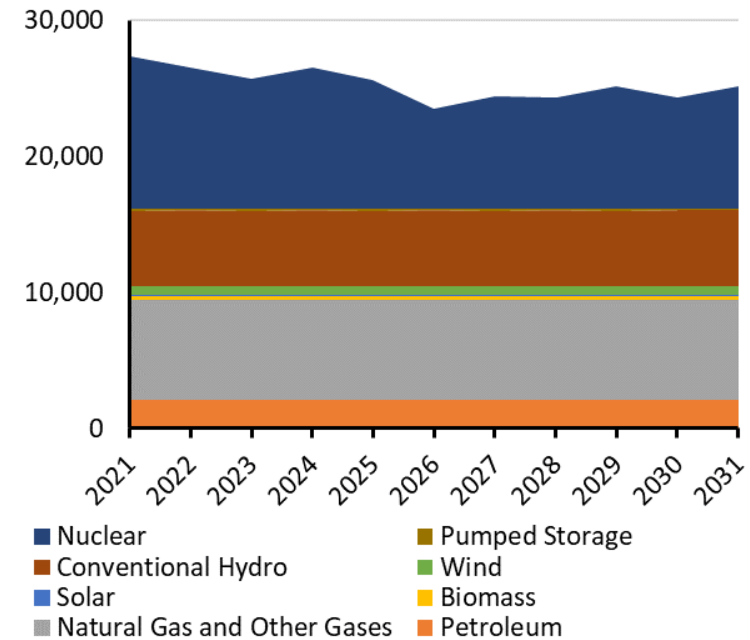
Additionally, the New York State Accelerated Renewable Energy Growth and Community Benefit Act seeks to accelerate siting and construction of large-scale clean energy projects and also authorized the New York Power Authority to undertake the development of priority transmission investments needed to achieve CLCPA targets. The New York Public Service Commission has authorized NYPA to pursue construction of its proposed Northern New York Transmission Expansion project. The project will increase the capacity of transmission lines in Northern New York.

The NYISO's interconnection process contains many proposed transmission projects in various stages of development.

Demand, Resources, and Reserve Margins (MW)										
Quantity	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Internal Demand	22,580	22,454	22,459	22,686	22,934	23,239	23,421	23,736	24,059	24,304
Demand Response	621	512	512	512	512	512	512	512	512	512
Net Internal Demand	21,959	21,942	21,948	22,175	22,422	22,727	22,910	23,224	23,547	23,792
Additions: Tier 1	23	23	23	23	23	23	23	23	23	23
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	26,510	25,726	26,535	25,603	23,506	24,377	24,337	25,148	24,340	25,153
Anticipated Reserve Margin (%)	20.83%	17.35%	21.00%	15.56%	4.93%	7.36%	6.33%	8.38%	3.46%	5.81%
Prospective Reserve Margin (%)	21.97%	18.49%	22.14%	16.69%	6.05%	8.46%	7.42%	9.46%	4.52%	6.86%
Reference Margin Level (%)	19.12%	15.88%	19.35%	23.08%	18.93%	17.87%	17.52%	21.38%	17.67%	19.94%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARMs fall below the Reference Margin level beginning in 2025, driven primarily by the nuclear shutdown and nuclear refurbishment program, expiring contracts, and demand growth.
- In December 2020, the IESO held its first capacity auction and secured capacity from resources that included generation, imports, storage, and DR.
- The IESO will continue addressing anticipated shortfalls by evolving and expanding the capacity auction and by launching a series of competitive procurements to secure resources to meet resource adequacy needs over the longer term.
- The IESO expects to see an increase in energy demand over the forecast horizon. In the near term, peaks are expected to remain fairly flat before increasing in later parts of the assessment period. Ontario will remain summer peaking over the forecast horizon.
- A number of transmission projects are underway to address bulk system reliability concerns, reinforce connection in the northwest part of the assessment area, and connect new loads in the southwest part of the assessment area.

NPCC-Ontario Fuel Composition (MW)										
Fuel	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Petroleum	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106	2,106
Natural Gas	7,329	7,322	7,329	7,322	7,329	7,322	7,329	7,322	7,329	7,329
Biomass	288	288	288	288	288	288	288	288	288	288
Solar	64	64	64	64	64	64	64	64	64	64
Wind	697	697	697	697	697	697	697	697	697	697
Conventional Hydro	5,539	5,539	5,539	5,539	5,539	5,539	5,539	5,539	5,539	5,539
Pumped Storage	109	109	109	109	109	109	109	109	109	109
Nuclear	10,401	9,623	10,426	9,501	7,397	8,275	8,228	9,046	8,231	9,044
Total MW	26,532	25,748	26,557	25,626	23,528	24,400	24,359	25,171	24,362	25,175

NPCC-Ontario Assessment

Planning Reserve Margins

The ARMs fall below the Reference Margin level beginning in 2025, driven primarily by the nuclear shutdown and nuclear refurbishment program, expiring contracts, and demand growth. Anticipated shortfalls of about 1,700 MW and 3,100 MW are forecast for 2025 and 2026 respectively. In order to address anticipated reserve shortfalls, the IESO is working with stakeholders through its resource adequacy engagement to implement a framework of competitive mechanisms to meet resource adequacy needs over a range of planning horizons, recognizing that a variety of procurement mechanisms will be required.[57] In December 2020, the IESO held its first capacity auction and secured 992.1 MW of summer capacity from resources that included generation, imports, storage, and DR. The IESO will continue to evolve and expand the annual capacity auction to address anticipated shortfalls over the operations planning horizon. In 2021, the IESO will launch the first in a series of competitive procurements to secure resources to meet resource adequacy needs beginning in 2026 over the long-term planning horizon. The IESO completes a probabilistic assessment of its resource adequacy needs annually and publishes the results in the Annual Planning Outlook.[58]

Nonpeak Hour Risks

Summer peaks have moved later in the day due to the increased penetration of embedded solar generation and the critical peak pricing program. Peaks are expected to increase over time due to reduced conservation program spending and plateauing DERs.

Demand

NPCC-Ontario will remain summer peaking over the forecast horizon. In the near term, peaks are expected to remain fairly flat as the province moves through the remnants of the COVID-19 pandemic and its economic impacts. Later in the forecast peaks are expected to increase over time due to reduced conservation program spending and plateauing embedded generation. The winter peak is subject to the same downward forces as the summer peak but the impacts are less pronounced in the winter. Economic and demographic impacts are expected offset these downward pressure from efficient lighting retrofits and lead to small increases in winter peaks.

Energy demand is subject to the same factors as peak demands. In the near term, there is demand forecast uncertainty due to COVID-19. However, demand is expected to experience upward pressure from economic and demographic growth in the long term. Growth will also come from electrification of the transportation sector and significant growth in the resource sector, primarily mining and agriculture. Overall, the IESO expects to see an increase in energy demand over the forecast horizon.

Demand Side Management

As of the December 2020 capacity auction, DR (including dispatchable loads and hourly DR resources) has been enabled to compete with other resources to provide capacity. Resources with capacity obligations are required to be available for curtailment up to their secured capacity during times of system need. The December 2020 capacity auction procured 992.1 MW for the six-month summer obligation period beginning on May 1, 2021. Of this capacity, 809.3 MW is from DR.

Distributed Energy Resources

The IESO estimates that total DERs exceed 4,300 MW, including about 4,000 MW of contracted renewable resources. The IESO continues to collaborate with the DER community to increase coordination between the grid operator and embedded resources directly or through integrated operations with local distribution companies with the aim to improve DER visibility and identify opportunities for a more coordinated operation of NPCC-Ontario's electricity system. Although the output from DERs has plateaued, the need for more flexible generation to manage variability remains. Given that DERs are challenging to forecast, it can be difficult to efficiently commit non-quick-start resources or schedule transactions on the interties to manage supply and demand. Currently, to manage this variability, IESO initiates actions like committing dispatchable generation, curtailing intertie transactions, and scheduling additional 30-minute operating reserve to signal flexibility need.

Generation

Nuclear refurbishments at Bruce and Darlington generating stations are expected to reduce the generation capacity availability in the coming years. During the refurbishment period, one to four units are expected to be on outage at any given time, including peak seasons. Once they return to service, they will continue to help meet adequacy requirements in the mid/longer term. Since the *2020 LTRA*, the operator of Pickering Nuclear Generating Station has received approval for extending the operation of two units from 2022 to the fall of 2024 and the remaining four units from the end of 2024 to the end of 2025. In addition to the 992.1 MW secured in the capacity auction for the Summer 2021 obligation period, Henvey Inlet Wind Farm (300 MW) was added to the grid in January 2021. Contracted wind capacity of 160 MW is expected to be added in 2021. Substantial resource turnover is anticipated in the coming years that is driven by nuclear retirements, nuclear refurbishments, and

[57] See IESO Resource Adequacy engagement: https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Resource-Adequacy-Engagement

[58] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

by the expiry of contracted resources. The availability of the nuclear fleet is a major resource turnover risk that requires additional attention. The transmission-connected supply mix has shifted from only synchronous generation facilities to more inverter-based generation facilities (e.g., wind, solar). There are very few natural-gas-fired generation facilities producing power under light demand conditions. As a result, the IESO-controlled grid relies primarily on baseload (run-of-the-river) hydroelectric generation facilities to provide most of the primary frequency response.

Energy Storage

The IESO views electricity storage as an important emerging resource and is actively working to enable its deployment. It has released a series of reports outlining barriers to fair competition and detailing a path for enduring participation of electricity storage resources in the IESO's markets. Nonetheless, capacity from transmission connected storage remains relatively small. There is a considerable amount of energy storage resources connected on the distribution system for peak shaving. Additional energy storage projects are expected and are at different stages of development from feasibility studies to permitting. Energy storage uses include regulation services, reactive support and voltage control, energy market participation, and BTM peak shaving.

Capacity Transfers

The IESO has operating agreements with Hydro Québec and Manitoba Hydro to enable system backed imports from these jurisdictions that may be acquired as part of the IESO's Capacity Auction. As part of the electricity trade agreement between NPCC-Ontario and NPPC-Québec, NPCC-Ontario will supply 500 MW of capacity to NPPC-Québec, each winter from December to March until 2023. NPCC-Ontario has the option to receive 500 MW of capacity from NPPC-Québec for one summer before 2030. The IESO and NYISO facilitates trading of capacity from NPCC-Ontario to NPCC-New York. To ensure that reliability in NPCC-Ontario is maintained, only capacity that is determined by the IESO to be above NPCC-Ontario's required Reserve Margin Levels over summer or winter season are exported.

Transmission

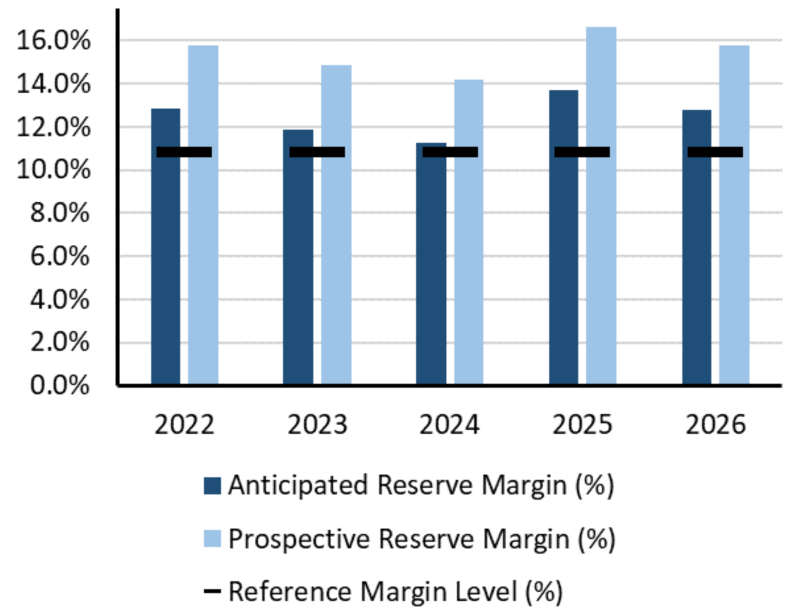
A new 400–450 km long 230 kV double-circuit transmission line is planned to come into service in Q1 2022 to reinforce the connection of Northwestern Ontario to the rest of the provincial grid. There is a double-circuit 230 kV line that is operated as one electrical circuit in the Sudbury area that poses system reliability risks should a contingency event occur. The IESO is in the pre-system impact assessment stage for a project to address those risks. In the Windsor-Essex area, two projects have been initiated: development of a new switching station expected in-service in Q3 2022 and a new double-circuit approximately 50 km 230 kV transmission line to bring additional supply to the area by Q4 2025. The IESO has recently recommended further transmission reinforcement to support the area's medium-term needs, identifying an additional double circuit 230 kV line with an expected in-service date of Q1 2028. In the Ottawa area, IESO has requested that work proceed to upgrade circuits between Merivale Transformer Station and Hawthorne Transformer Station with a planned in-service date of Q4 2023; this project will address supply capacity constraints to West Ottawa and support the deliverability of capacity imports from Québec. The IESO has recommended the upgrade of four 230 kV circuits between Richview TS and Trafalgar TS in the Toronto area that are the limiting elements for the Flow East toward Toronto Interface by Spring 2026. In Eastern Ontario, high voltage levels have been observed due to low transfer levels across the 500 kV transmission system. To mitigate the issue, two 500 kV line-connected shunt reactors will be installed with a planned in-service date of Q1 2022.

Reliability Issues

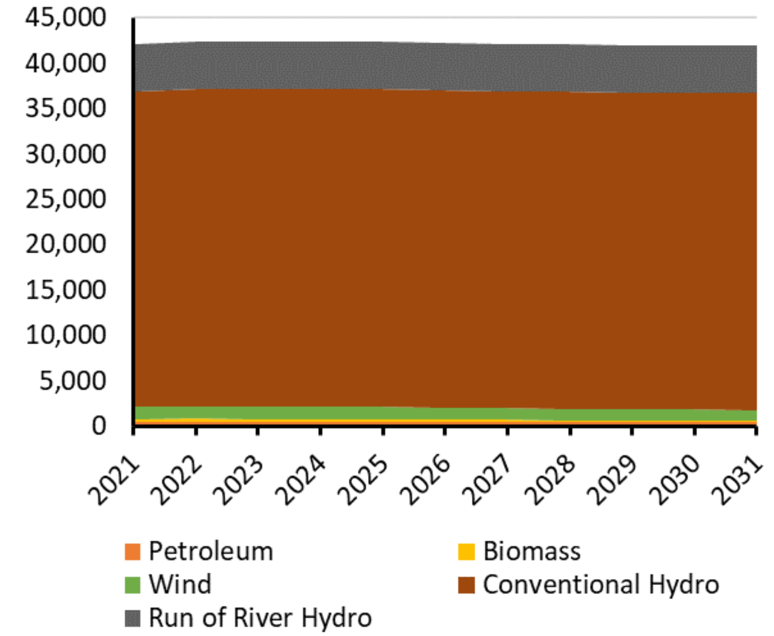
The ongoing nuclear refurbishment program that spans the next 12 years is a major resource risk that requires additional attention. The IESO has regular meetings with nuclear operators to assess probable delays and to take appropriate mitigation actions.

Natural gas is delivered to NPCC-Ontario from neighboring jurisdictions by mainlines and distribution utilities. Situated in NPCC-Ontario is the Dawn storage hub, Canada's largest integrated underground natural gas storage facility. The risk of fuel unavailability under extreme winter conditions is reduced with a large portion of the natural gas fleet located in close proximity to the Dawn hub. Supply to NPCC-Ontario's natural gas fleet is robust and supported by significant firm supply and transportation contracts.

Demand, Resources, and Reserve Margins (MW)										
Quantity	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Internal Demand	39,758	40,171	40,493	40,759	41,089	41,428	41,798	42,056	42,285	42,482
Demand Response	2,587	3,108	3,357	3,617	3,758	3,984	4,043	4,073	4,073	4,073
Net Internal Demand	37,172	37,063	37,136	37,142	37,331	37,443	37,755	37,983	38,212	38,409
Additions: Tier 1	282	282	322	322	322	322	322	322	322	322
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-417	-888	-1,079	-145	-145	-145	-145	-145	0	0
Existing-Certain and Net Firm Transfers	41,655	41,176	40,985	41,901	41,788	41,755	41,653	41,602	41,737	41,666
Anticipated Reserve Margin (%)	12.8%	11.9%	11.2%	13.7%	12.8%	12.4%	11.2%	10.4%	10.1%	9.3%
Prospective Reserve Margin (%)	15.8%	14.8%	14.2%	16.6%	15.7%	15.3%	14.1%	13.3%	12.9%	12.2%
Reference Margin Level (%)	10.8%	10.8%	10.8%	10.8%	10.8%	10.8%	10.8%	10.8%	10.8%	10.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the Reference Margin Level except for later winter periods of this assessment. The Prospective Reserve Margin is above the Reference Margin Level for all years of the assessment period.
- Approximately 353 MW of capacity additions are expected over the assessment period. The Romaine-4 hydro unit (245 MW) is expected to be fully operational by 2023.
- A total of 500 MW of firm import capacity from Ontario is available to Québec each winter through winter 2022–2023 as part of an existing trade agreement between NPCC-Québec and NPCC-Ontario.
- The commissioning of the second Micoua-Saguenay 735 kV line is expected by the end of 2022.

NPCC-Québec Fuel Composition (MW)										
Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Petroleum	436	436	436	436	436	436	436	436	436	436
Biomass	413	405	405	405	350	295	231	228	228	228
Wind	1,375	1,375	1,375	1,356	1,298	1,262	1,223	1,175	1,175	1,117
Conventional Hydro	34,918	34,918	34,918	34,918	34,918	34,918	34,918	34,918	34,918	34,918
Run of River Hydro	5,211	5,211	5,252	5,252	5,252	5,252	5,252	5,252	5,242	5,229
Total MW	42,354	42,346	42,387	42,368	42,255	42,164	42,061	42,009	41,999	41,928

NPCC-Québec Assessment

Planning Reserve Margins: The ARM is based on existing and anticipated generating capacity and firm capacity transfers. It is above the area Reference Margin Level throughout the assessment period except for the last three winter periods (2029–2032). However, the Prospective Reserve Margin remains above the Reference Margin Level for almost all seasons and years during the assessment period. Under the prospective scenario, the NPPC-Québec area planned 1,100 MW of expected capacity supply; this capacity could either be supplied by resources within the area or by imports. This capacity has not yet been backed by firm long-term contracts. However, based on its annual capacity needs, the NPPC-Québec area proceeds with short-term capacity contracts in order to meet its capacity requirements.

Demand: The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand. The NPPC-Québec area demand forecast average annual growth is 0.9% during the 10-year period, slightly higher than last year's forecast.

Demand-Side Management: The NPPC-Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 1,500 MW on Winter 2021-2022 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will grow from 325 MW in 2021 to 470 MW by the end of the assessment period. Another similar program for residential customers is in operation and should gradually rise from 28 MW for Winter 2021–2022 to 621 MW for Winter 2028–2029. The enhancement of the interruptible program for large industrial customers will provide additional potential capacity that varies from 310 MW beginning in 2023 to 480 MW at the end of the assessment period.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 88 MW for Winter 2021-2022, increasing to 330 MW for Winter 2031–2032.

Moreover, data centers specialized in blockchain applications, which are part of new developments in the commercial sector, are required to reduce their demand during peak hours at Hydro-Québec Distribution's request. Their contribution as a resource is expected to be around 178 MW for Winter 2021–2022 and reach 230 MW at the end of the study period.

Finally, another demand-side resource consists of a voltage reduction scheme that provides for a 250 MW peak demand reduction.

EE and conservation programs are integrated in the assessment area's demand forecasts.

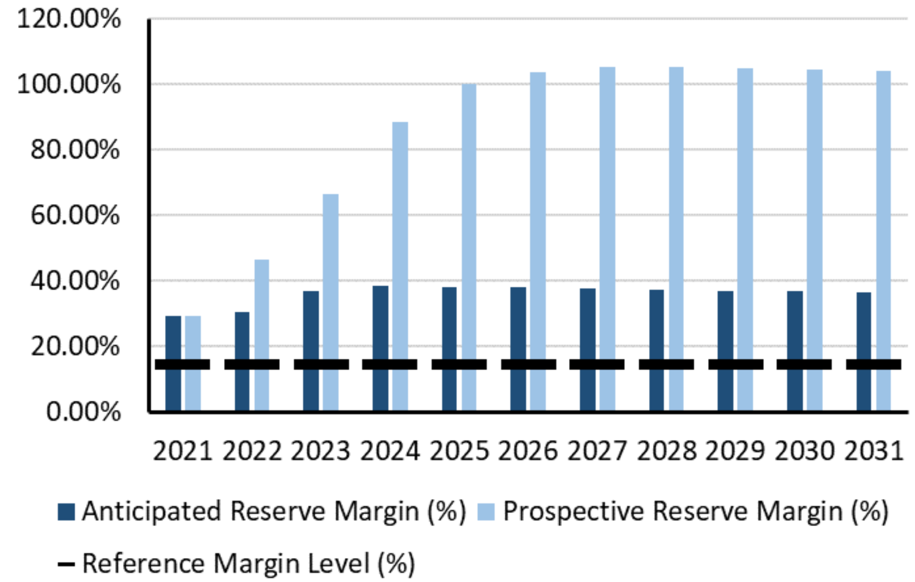
Distributed Energy Resources: Total installed BTM capacity (solar PV) is expected to increase to more than 622 MW in 2032. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter-peaking area, solar PV on-peak contribution ranges from 2 MW for Winter 2021–2022 to 10 MW for Winter 2031–2032. No potential operational impacts of DERs are expected in the NPPC-Québec area, considering the low DER penetration in the area.

Generation: The Romaine-4 unit (245 MW) is expected to be fully operational by the end of 2022. The refurbishment of the Rapide-Blanc generating station is expected to start this year and the next return to service is expected to be in 2022. The integration of small hydro unit accounts for 41 MW new capacity during the assessment period. For other renewable resources, 48 MW (17 MW on-peak value) is expected to be in service by the end of 2021. Additionally, 19 MW of new biomass is expected to be in service by the end of 2022.

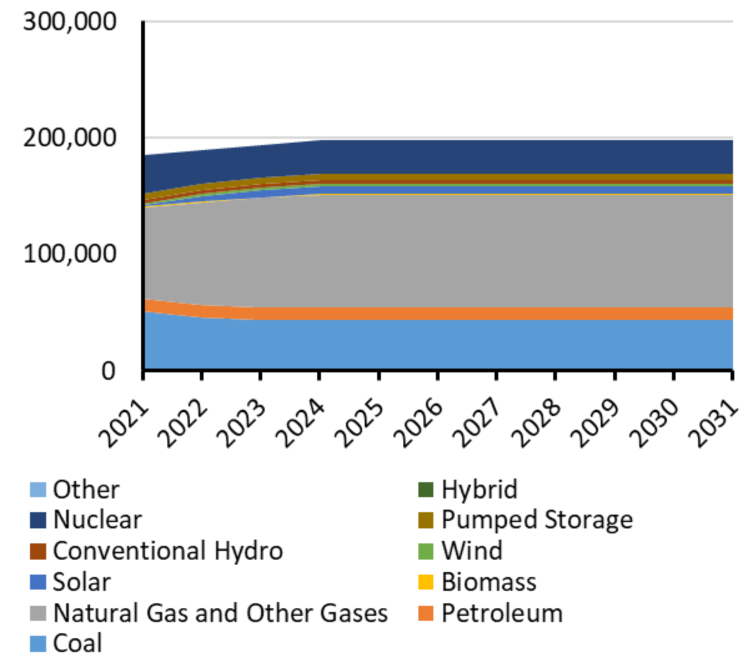
Capacity Transfers: In 2019, Hydro-Québec TransÉnergie conducted a Transmission System Planning Assessment to fulfill NERC TPL-001-4 requirements. The assessment indicated that the loss of a 735 kV circuit on the Manic-Québec interface while a 735 kV line is already out-of-service and system adjustments are applied caused the overload of the Saguenay series capacitor banks even considering their overload capacity. The commissioning of the second Micoua–Saguenay 735 kV line is planned for 2023. Simulations performed on the 2023–2024 and 2028–2029 systems have confirmed the effectiveness of this solution. Until then, this issue is monitored and addressed in real-time with a system operating limit, and power transfer is limited if an overload risk is detected. This new line is now under construction and is expected to be in service in 2023.

Transmission: Construction of the Romaine River Hydro Complex project is presently underway. Its total capacity will be 1,550 MW. Romaine-2 (640 MW) has been commissioned in 2014, Romaine-1 (270 MW) in 2015 and Romaine-3 (395 MW) in 2017. Romaine-4 (245 MW) is expected to be in service by the end of 2022. A new 735 kV line extends some 250 km (155 miles) between Micoua substation in the Côte-Nord area and Saguenay substation in Saguenay–Lac–Saint-Jean. The project also includes adding equipment to both substations and expanding Saguenay substation. This project is now under construction phase and planned to be in service in 2022.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	149,966	150,855	151,503	151,928	152,290	152,571	152,971	153,268	153,536	153,759
Demand Response	8,824	8,861	8,888	8,910	8,927	8,931	8,947	8,961	8,973	8,982
Net Internal Demand	141,142	141,994	142,615	143,018	143,363	143,640	144,024	144,307	144,563	144,777
Additions: Tier 1	14,316	21,838	25,356	25,356	25,356	25,356	25,356	25,356	25,356	25,356
Additions: Tier 2	20,898	44,976	74,286	91,275	97,023	100,106	100,640	100,640	100,789	100,789
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-4,837	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	169,958	172,423	172,423	172,423	172,423	172,423	172,423	172,423	172,423	172,423
Anticipated Reserve Margin (%)	30.56%	36.81%	38.68%	38.29%	37.96%	37.69%	37.32%	37.05%	36.81%	36.61%
Prospective Reserve Margin (%)	46.71%	66.41%	88.71%	100.05%	103.58%	105.34%	105.16%	104.76%	104.50%	104.19%
Reference Margin Level (%)	14.50%	14.40%	14.40%	14.40%	14.40%	14.40%	14.40%	14.40%	14.40%	14.40%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

The ARMs for each year in the assessment period do not fall below the PJM Installed Reserve Requirement (Reference Margin Level).

PJM Fuel Composition (MW)										
Fuel	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Coal	45,641	43,348	43,348	43,348	43,348	43,348	43,348	43,348	43,348	43,348
Petroleum	11,414	11,414	11,414	11,414	11,414	11,414	11,414	11,414	11,414	11,414
Natural Gas	87,209	93,474	96,471	96,471	96,471	96,471	96,471	96,471	96,471	96,471
Biomass	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005	1,005
Solar	5,060	6,156	6,546	6,546	6,546	6,546	6,546	6,546	6,546	6,546
Wind	1,948	1,994	2,006	2,006	2,006	2,006	2,006	2,006	2,006	2,006
Conventional Hydro	3,005	3,005	3,026	3,026	3,026	3,026	3,026	3,026	3,026	3,026
Pumped Storage	5,220	5,220	5,220	5,220	5,220	5,220	5,220	5,220	5,220	5,220
Nuclear	28,559	28,559	28,559	28,559	28,559	28,559	28,559	28,559	28,559	28,559
Hybrid	23	39	103	103	103	103	103	103	103	103
Other	27	48	82	82	82	82	82	82	82	82
Total MW	189,111	194,261	197,780	197,780	197,780	197,780	197,780	197,780	197,780	197,780

PJM Assessment

The ARMs for each year in the assessment period do not fall below the PJM Installed Reserve Requirement (Reference Margin Level). Because PJM has extensive capacity resources, risk for capacity shortages during non-peak periods are minimal. The highest risk periods are the end of the spring and fall outage seasons when numerous outages are taken to maintain generation and transmission. Some outages can take longer than planned and extend into the beginning of the peak period (June 1 through September 15 and December 1 through March 15). Careful planning and operational time frame outage denial minimizes the risks of possible capacity shortages.

PJM is expecting a low risk of experiencing periods of resources falling below required operating reserves during upcoming peak periods. PJM is forecasting around 30% installed reserves (including expected committed demand resources), well above the target installed reserve margin of 14.7% necessary to meet the 1-day-in-10 years LOLE criterion. PJM 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 demand. To address potential future reliability concerns due to limitations associated with the performance of limited and variable resources, PJM has filed an effective load carrying capability methodology with FERC to properly calculate the reliability and capacity contribution of limited and variable resources.

The PJM Interconnection produces an independent peak load forecast of total internal demand using econometric regression models with daily load as the dependent variable and independent variables including calendar effects, weather, economics, and end-use characteristics. Daily unrestricted peak load is defined as metered load plus estimated load drops and estimated distributed solar generation. Separately from the modeled forecast, a forecast of the peak impact of distributed solar generation is developed, using internal installed solar capacity data and a forecast of solar capacity additions obtained from a vendor. Impact on peak is estimated by applying a historical capacity factor to installed capacity. Additionally, a separate forecast of load management is developed, based on the amount of resources that have historically committed though PJM's FCM. The load management forecast is used to develop the net internal demand forecast.

PJM annually reviews its load forecast methodology and implements changes when improvements are identified. For the 2021 load forecast, the major changes encompassed refinements to sector models and non-weather-sensitive load, both of which were first introduced with the 2020 load forecast. With respect to sector models, the commercial component of the load model was improved with the addition of service sector employment to more accurately reflect evolving economic conditions. Improvements to non-weather-sensitive models were also made to better align with underlying drivers and historical trends, reducing expected load impacts. Each year, PJM measures the accuracy of the long-term load forecast model by running it with up-to-date inputs, solving with actual weather and comparing to actual load. This measure of accuracy is meant to show how well the model would have performed with the most recent forecast inputs. PJM reviews model accuracy results on the ten highest coincident peak days for each season, for a number of forecast horizons with the Load Analysis Subcommittee.

DR resources can participate in all PJM markets: capacity, energy, and ancillary services:

Capacity: Capacity service providers have the ability to participate in PJM reliability pricing model (RPM) auctions up to three years in advance of the delivery year (PJM delivery year is June-May).

Energy: DR resources may register for and bid into PJM day ahead and real-time energy (economic) markets.

Ancillary Services: DR resources may register for and must be certified for participation in PJM ancillary service markets as per the requirements for each ancillary service type as found in PJM manuals.

PJM expects[59] 3,176 MW of solar DER at the time of the peak in 2024 and 5,828 MW in 2031. The effects of solar DER are included in the load forecast for PJM. No effect of solar DER is incorporated in the winter load forecast since winter expected peak occurs after sundown.

PJM processed 1,028 requests to interconnect new generation, totaling 70,375 MW, nameplate capability and 44,179 MW of capacity interconnection rights. Wind, solar, and storage requests now total over 120,000 MW (nameplate) in PJM's interconnection queue. Solar has more than doubled over 2019, now comprising 56% of PJM's queue.

[59] https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx

PJM's existing installed capacity reflects a fuel mix comprising approximately 43% natural gas, 27% coal, and 18% nuclear. Hydro, wind, solar, oil, and waste fuels constitute the remaining 11%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling over 76,000 MW (nameplate), renewable fuels are changing the landscape of PJM's interconnection queue. Solar energy comprises 56% of the generation in PJM's interconnection queue, a 13% increase over the previous year. An increase in solar generation interconnection requests is attributable to state policies encouraging renewable generation.

Prior to 2021, variable resource capacity value was set at a resource's average output over a defined number of summer peak load hours. This approach has two limitations: it weights the output over all hours equally, regardless of an individual hour's actual contribution to the annual loss of load risk, and it fails to recognize the saturation effect as the amount of intermittent resources in PJM increases. To address these two limitations, PJM performed analysis to assess the reliability value of intermittent resources by using an effective load carrying capability (ELCC) methodology. This more robust methodology recognizes the full value of a resource's output over high-load risk hours and also accounts for the saturation effect. As part of the process to implement the ELCC, a proposal was developed. PJM now requires generation owners of ELCC resources to provide specific information about their resources. This information is used by PJM as input to its resource adequacy model. Pending FERC approval, the ELCC methodology will be applied to variable, limited-duration and hybrid resources beginning with the 2023/2024 delivery year.

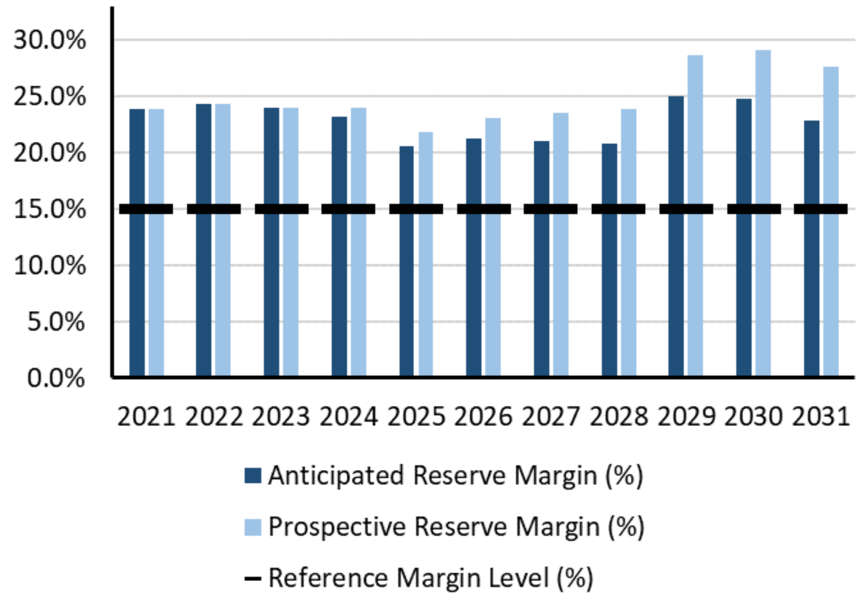
Energy storage continues to grow in PJM. Efficient grid operations in an era experiencing rapid growth of variable renewable resources will require increased electric system flexibility. Energy storage provides grid operators the ability to meet load requirements when wind, solar, and other variable resources must alter power output because of weather conditions or because those units simply are unavailable. Energy storage resources can also improve transmission system efficiency by increasing network utilization factors. PJM has worked with several industry entities, including DOE national laboratories, to advance the use of energy storage and ensure that PJM's wholesale market is capable of allowing all forms of energy storage technology to participate competitively.

A 15-year, long-term planning horizon allows PJM to consider the aggregate effects of many drivers. Initially, with its inception in 1997, PJM's Regional Transmission Expansion Plan (RTEP) consisted of system enhancements mainly driven by load growth and generating resource interconnection requests. Today, PJM's RTEP process studies the interaction of many drivers, including those arising out of reliability, aging infrastructure, operational performance, market efficiency, public policy, and demand-side trends. Importantly though, RTEP development considers all drivers through a reliability criteria and resilience lens. PJM's RTEP process encompasses a comprehensive assessment of system compliance with the thermal, reactive, stability, and short-circuit NERC Standard TPL-001-4.

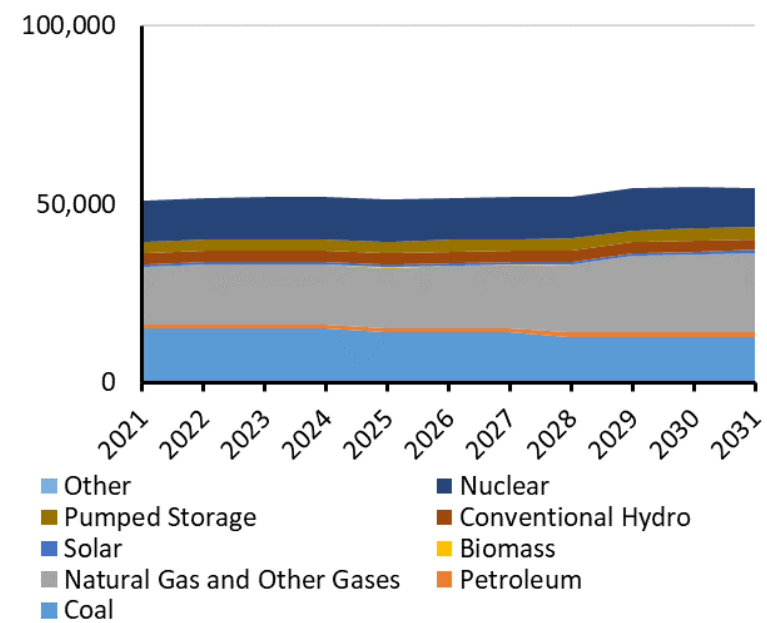
Historically, baseline transmission projects have been driven by reliability criteria, market efficiency needs, and TO criteria requirements. PJM's state agreement approach, authorized by FERC, expands the planning process to enable a state or group of states to propose a project to advance public policy requirements as long as the states involved agree to pay all costs of any related build-out included in the RTEP. The state agreement approach was developed seven years ago after extensive consultation with the Organization of PJM States (OPSI) as part of implementing FERC's Order 1000. In that order, FERC required regional grid operators to "provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes."

No other reliability issues have been identified that are unique to PJM.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	43,058	43,294	43,693	43,979	44,105	44,378	44,599	45,061	45,446	45,921
Demand Response	969	976	983	990	994	994	995	996	997	998
Net Internal Demand	42,089	42,318	42,710	42,989	43,111	43,384	43,604	44,065	44,449	44,923
Additions: Tier 1	486	561	616	981	1,400	1,819	3,076	5,484	5,903	6,322
Additions: Tier 2	0	14	369	520	761	1,070	1,361	1,637	1,899	2,155
Additions: Tier 3	36	100	177	5,513	5,645	6,672	6,934	7,249	7,669	8,176
Net Firm Capacity Transfers	562	562	562	562	562	562	562	562	562	562
Existing-Certain and Net Firm Transfers	51,837	51,917	51,984	50,886	50,886	50,714	49,584	49,590	49,590	48,850
Anticipated Reserve Margin (%)	24.3%	24.0%	23.2%	20.7%	21.3%	21.1%	20.8%	25.0%	24.8%	22.8%
Prospective Reserve Margin (%)	24.3%	24.0%	24.0%	21.9%	23.0%	23.6%	23.9%	28.7%	29.1%	27.6%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



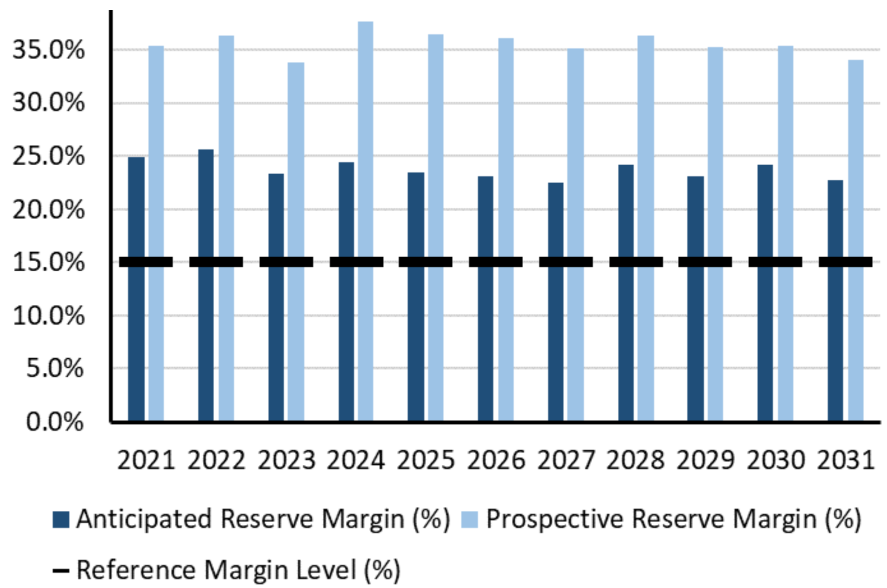
Planning Reserve Margins



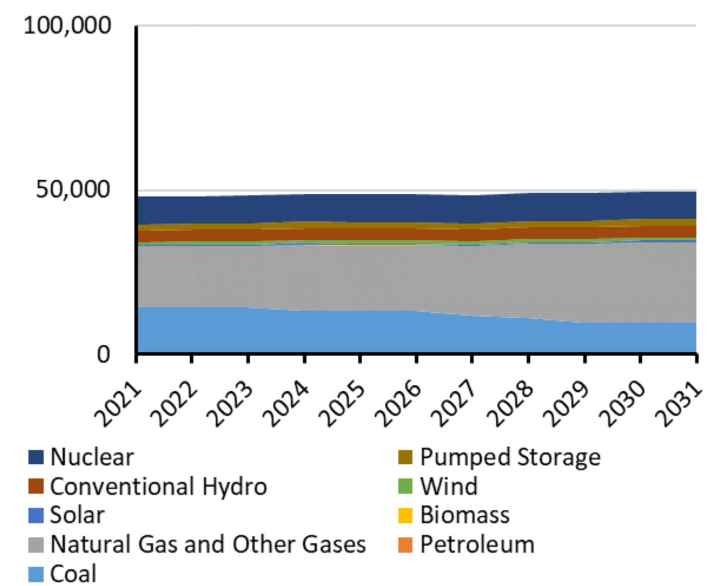
Existing and Tier 1 Resources

SERC-East Fuel Composition (MW)										
Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	15,051	15,051	15,051	13,953	13,953	13,953	12,823	12,823	12,823	12,823
Petroleum	1,174	1,174	1,174	1,174	1,174	1,122	1,122	1,122	1,122	1,141
Natural Gas	16,669	16,669	16,669	17,034	17,453	17,748	19,005	21,413	21,832	22,251
Biomass	76	76	76	76	76	76	76	76	76	76
Solar	716	791	846	846	846	846	846	846	846	846
Conventional Hydro	3,099	3,099	3,099	3,099	3,099	3,099	3,099	3,099	3,099	3,099
Pumped Storage	3,189	3,254	3,319	3,319	3,319	3,319	3,319	3,319	3,319	3,319
Nuclear	11,780	11,795	11,797	11,797	11,797	11,801	11,801	11,807	11,807	11,048
Other	7	7	7	7	7	7	7	7	7	7
Total MW	51,761	51,916	52,038	51,305	51,724	51,971	52,098	54,512	54,931	54,610

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	40,181	40,967	41,086	41,193	41,305	41,349	41,390	41,480	41,581	41,625
Demand Response	1,691	1,693	1,693	1,691	1,690	1,688	1,687	1,685	1,684	1,678
Net Internal Demand	38,490	39,274	39,393	39,502	39,615	39,661	39,703	39,795	39,897	39,947
Additions: Tier 1	356	406	1,720	2,268	2,268	3,721	5,174	6,270	6,818	6,818
Additions: Tier 2	62	62	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282
Additions: Tier 3	0	502	965	1,485	2,098	2,490	2,626	2,762	2,898	3,034
Net Firm Capacity Transfers	101	101	101	101	101	101	101	-74	-74	-552
Existing-Certain and Net Firm Transfers	47,996	48,038	47,305	46,505	46,505	44,850	44,112	42,732	42,702	42,224
Anticipated Reserve Margin (%)	25.6%	23.4%	24.5%	23.5%	23.1%	22.5%	24.1%	23.1%	24.1%	22.8%
Prospective Reserve Margin (%)	36.3%	33.8%	37.7%	36.4%	36.0%	35.1%	36.3%	35.2%	35.4%	34.0%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



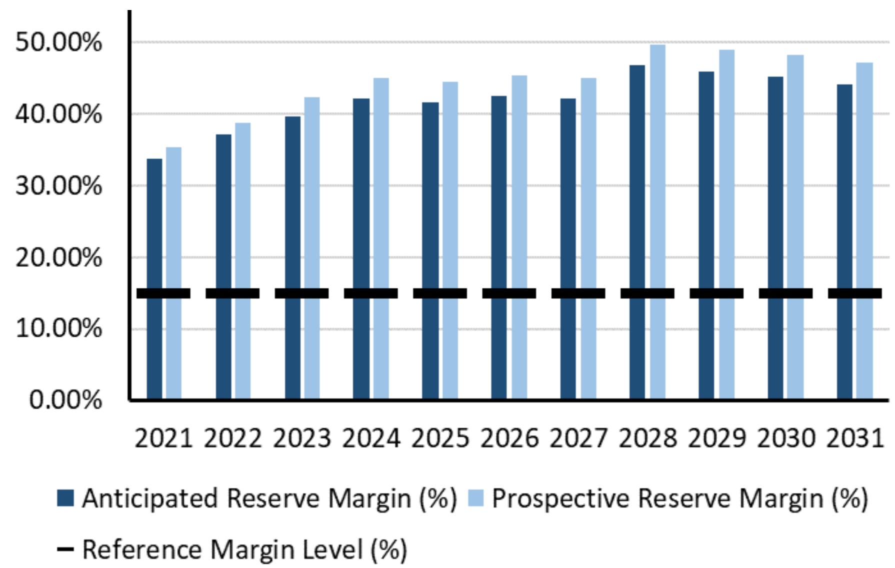
Planning Reserve Margins



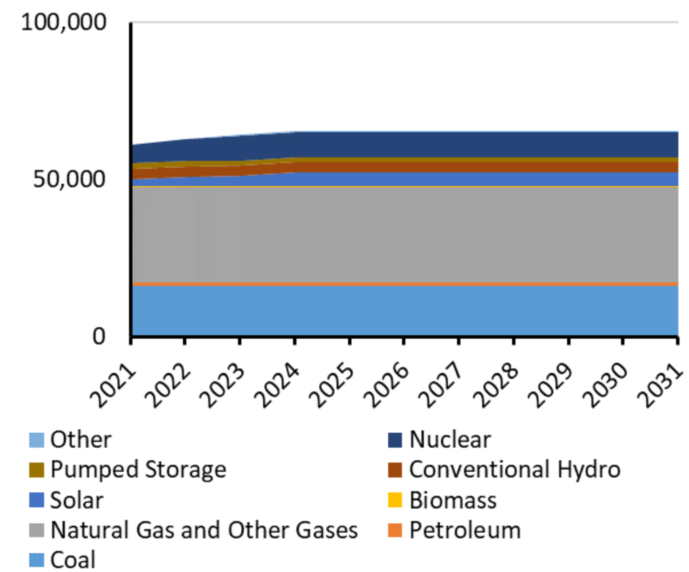
Existing and Tier 1 Resources

SERC-Central Fuel Composition (MW)										
Fuel	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Coal	14,162	14,162	13,402	13,402	13,402	11,747	11,009	9,804	9,804	9,804
Petroleum	20	20	20	20	20	20	20	20	20	20
Natural Gas	18,670	18,670	19,984	19,732	19,732	21,185	22,638	23,734	24,252	24,252
Biomass	44	44	44	44	44	44	44	44	44	44
Solar	538	538	538	538	538	538	538	538	538	538
Wind	958	958	958	958	958	958	958	958	958	958
Conventional Hydro	3,572	3,604	3,604	3,604	3,604	3,604	3,604	3,604	3,604	3,604
Pumped Storage	1,848	1,859	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886
Nuclear	8,439	8,439	8,439	8,439	8,439	8,439	8,439	8,439	8,439	8,439
Other	0	50	50	50	50	50	50	50	50	50
Total MW	48,251	48,343	48,924	48,672	48,672	48,470	49,185	49,076	49,594	49,594

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	47,352	47,420	47,549	47,735	47,544	47,706	46,266	46,526	46,749	47,065
Demand Response	1,707	1,708	1,792	1,797	1,793	1,798	1,805	1,811	1,811	1,803
Net Internal Demand	45,645	45,712	45,757	45,938	45,751	45,908	44,461	44,715	44,938	45,262
Additions: Tier 1	1,858	3,153	4,312	4,312	4,312	4,312	4,312	4,312	4,312	4,312
Additions: Tier 2	0	473	593	593	593	593	593	593	593	593
Additions: Tier 3	2,813	3,668	3,818	3,818	3,818	3,818	3,818	3,818	3,818	3,818
Net Firm Capacity Transfers	-548	-579	-557	-534	-430	-383	-382	-379	-377	-375
Existing-Certain and Net Firm Transfers	60,735	60,704	60,726	60,737	60,900	60,947	60,948	60,951	60,953	60,955
Anticipated Reserve Margin (%)	37.1%	39.7%	42.1%	41.6%	42.5%	42.2%	46.8%	46.0%	45.2%	44.2%
Prospective Reserve Margin (%)	38.7%	42.3%	45.0%	44.5%	45.4%	45.0%	49.8%	48.9%	48.2%	47.1%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



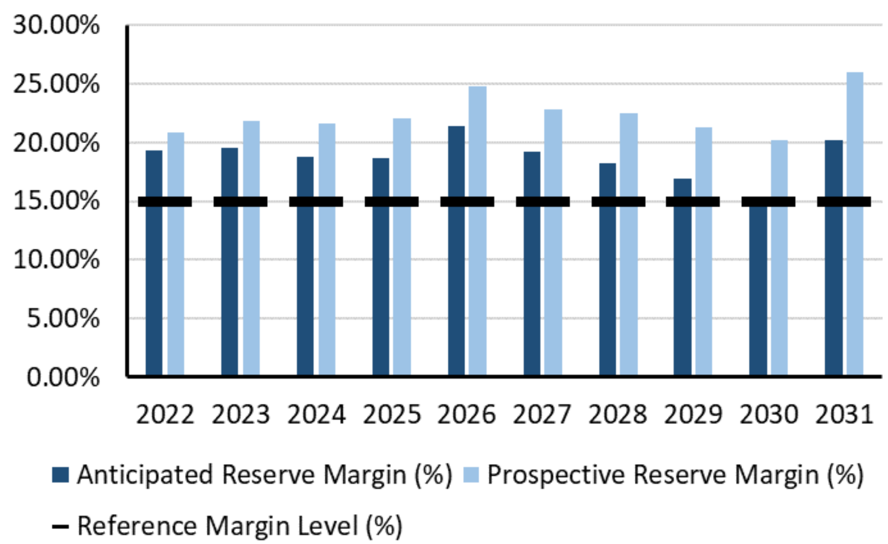
Planning Reserve Margins



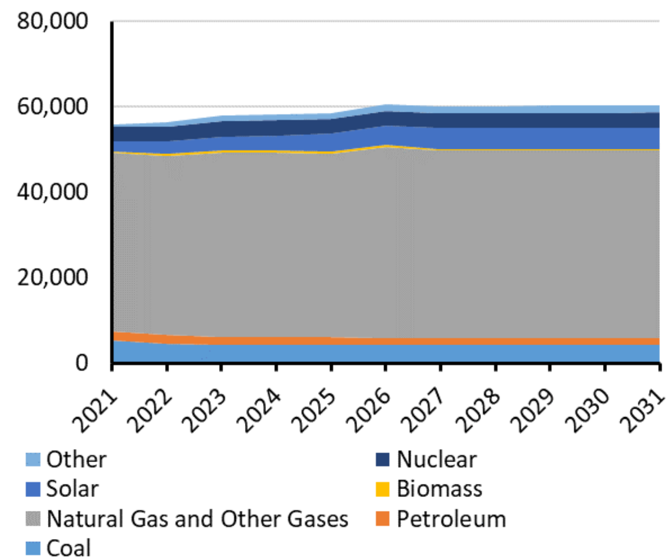
Existing and Tier 1 Resources

SERC-Southeast Fuel Composition (MW)										
Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	16,410	16,410	16,410	16,410	16,410	16,410	16,410	16,410	16,410	16,410
Petroleum	961	961	961	961	961	961	961	961	961	961
Natural Gas	30,303	30,303	30,303	30,291	30,350	30,350	30,350	30,350	30,350	30,350
Biomass	394	394	394	394	394	394	394	394	394	394
Solar	2,918	3,113	4,272	4,272	4,272	4,272	4,272	4,272	4,272	4,272
Conventional Hydro	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288	3,288
Pumped Storage	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632	1,632
Nuclear	6,918	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018
Other	317	317	317	317	317	317	317	317	317	317
Total MW	63,141	64,436	65,595	65,583	65,642	65,642	65,642	65,642	65,642	65,642

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	49,817	50,274	50,840	51,225	51,668	52,122	52,606	53,310	54,085	51,879
Demand Response	1,258	1,268	1,272	1,281	1,289	1,296	1,301	1,306	1,310	1,160
Net Internal Demand	48,559	49,006	49,568	49,944	50,379	50,826	51,305	52,004	52,775	50,719
Additions: Tier 1	3,074	4,980	5,453	5,979	8,262	8,717	8,767	8,901	8,951	9,085
Additions: Tier 2	0	374	674	973	973	1,123	1,487	1,562	1,851	2,226
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	1,414	579	579	579	479	479	479	479	479	479
Existing-Certain and Net Firm Transfers	54,868	53,610	53,418	53,265	52,887	51,886	51,886	51,886	51,886	51,886
Anticipated Reserve Margin (%)	19.3%	19.6%	18.8%	18.6%	21.4%	19.2%	18.2%	16.9%	15.3%	20.2%
Prospective Reserve Margin (%)	20.8%	21.8%	21.6%	22.0%	24.8%	22.9%	22.5%	21.3%	20.2%	26.0%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Florida Peninsula Fuel Composition (MW)										
Fuel	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Coal	4,655	4,260	4,260	4,260	4,260	4,260	4,260	4,260	4,260	4,260
Petroleum	1,949	1,949	1,949	1,949	1,778	1,650	1,650	1,650	1,650	1,650
Natural Gas	42,057	43,128	43,039	42,961	44,733	43,895	43,895	43,895	43,895	43,895
Biomass	485	485	481	443	443	408	408	408	408	408
Solar	2,776	3,249	3,621	4,110	4,458	4,863	4,863	4,947	4,947	5,031
Nuclear	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,499	3,499
Other	1,108	1,443	1,443	1,443	1,500	1,550	1,600	1,650	1,700	1,750
Total MW	56,527	58,011	58,292	58,665	60,670	60,124	60,174	60,308	60,358	60,492

SERC Assessment

Highlights

- All SERC assessment areas are projected to maintain sufficient capacity to meet the reliability PRM during the assessment time frame.
- The Regional Entity continues to see the growth in natural-gas-fired generation. Natural-gas-fired generation capacity is projected to make up over 50% of the generating capacity for the first time (approximately 155,000 MW).
- SERC is proactively addressing the impacts of increased renewable resources within the SERC footprint and identifying its risks through various forums.

Planning Reserve Margins

ARMs are at or above approximately 20% in all assessment areas and do not fall below the NERC 15% target Reference Margin Level at any point during the assessment period.

The SERC Resource Adequacy Working Group is beginning to explore developing a SERC subregional reliability Reference Margin Level for use in determining resource adequacy with the change in resource mix and growth of IBRs.

SERC will continue to use the NERC target Reference Margin Level of 15%, until a new probabilistic study is completed in 2022.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

SERC is made up of many members that perform their own internal studies as well as participate in studies under the direction of the SERC Engineering Committee. Some entities have performed studies to evaluate the fuel resiliency of all generating assets in their portfolios: fuel supply, fuel delivery, inventory, and backup contingencies determine the potential impact that fuel diversity has on the PRM. The result of this study suggested that overall fuel supply position is among the most resilient in the United States due to a diverse generation portfolio, advantageous location with respect to major gas pipelines, access to multiple coal supply and transport options, and a strong and resilient program to secure nuclear fuel.

Additionally considerations in reserve margin studies include a wide range of peaking conditions, including extreme weather conditions and historical water conditions to determine individual reserve requirements. Those peaking conditions cover all off-peak period. Low water conditions and the impact that they have on the equivalent forced outage rates are also included in the studies. VERs are assigned monthly net dependable capacities based on review of historical performance and/or historical irradiance in the geographical area.

To investigate the impact of planned maintenance outages on system risk, SERC conducted a sensitivity study in the 2020 ProbA that increased the amount of planned maintenance outages on the SERC system for year 2024. This sensitivity study helps resource adequacy planners understand how planned maintenance outages can affect the distribution of loss of load risk across all times of the year. In addition, it improves the ability to plan maintenance outage schedules that minimize loss of load risk.[60]

Demand

Methods to develop total internal demand projections vary amongst the entities in each assessment area. Utilities monitor load projections, weather patterns, economic patterns, emerging technology (electric vehicles), and customer growth to determine forecast models and other factors. They also use statistical models to calculate naturally occurring trends.

Projected demand growth within the assessment areas has decreased to about .5% over the years, with the exception of the SERC-Florida Peninsula, which has a growth rate of slightly above 1%. An additional outlier is SERC-Southeast, which is forecasting a relatively flat growth rate (-.01%). Although some metro areas are experiencing higher growth rates compared to rural areas, entities report load reductions due to BTM distributed generation and appliance standards. These factors will continue suppressing the load in the future.

Demand Side Management

Entities within the SERC Regional Entity use a variety of controllable and dispatchable DR programs to reduce peak demand. Larger commercial and industrial customers may participate in incentive programs to reduce exposure to high power prices, often referred to as interruptible load. Generally, these types of programs require a minimum lead-time to implement and may, or may not, have a limited number of implementations in order to mitigate reliability impacts on the BES.

[60] See *NERC 2020 Probabilistic Assessment Risk Scenarios Report*: https://www.nerc.com/comm/RSTC/PAWG/2020%20ProbA%20Regional%20Risk%20Scenarios%20Report_final_approved.pdf

Entities may also directly control residential switches and devices, referred to as direct control load management, to reduce peak demand dispatched for up to a certain amount of hours annually. Dispatchable voltage regulation programs that reduce peak demand by optimizing distribution-level voltage are another tool at entities' disposal.

The dispatchable voltage regulation programs historically mitigate local reliability issues. However, recent pilot programs in the SERC Regional Entity aggregate multiple states' DR programs to provide sub-regional DR similar to the interruptible load programs dispatched up to a certain amount of times annually. This is to mitigate high power prices and with unlimited implementation for reliability events.

The capacity available on peak of these types of programs depends on contractual obligations and historical performance de-rates, which are largely weather dependent. Throughout the year, entities monitor and evaluate each program's operational functionality to determine effectiveness and ability to provide demand reduction.

Distributed Energy Resources

Entities continue to monitor DER penetration levels, assess the impacts from DER, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (rooftop solar, plug-in electric vehicles, etc.) are netted against load in the energy management system and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar.

To date, there are no notable reliability impacts reported to the Regional Entity. Development of a SERC-wide estimated penetration forecast is not available at this time for BTM. The SERC Variable Energy Resources Working Group continues to evaluate the appropriate methods of evaluating the growth of solar in the SERC Regional Entity.

Generation

SERC entities have sufficient generation to meet demand over the period. New resources are expected, which include a combination of capacity purchases, new nuclear, natural gas, and combined-cycle units. Natural gas (50.2%), coal (24.1%), and nuclear (13.2%) generation are the dominant fuel types within the assessment areas. Hydro, renewables, and other fuel types (12%) are minimal. Entities within SERC will add approximately 13,000 MW of natural gas generation over the period. Natural gas continues to grow in the SERC Regional Entity; natural gas now makes up over half of the fuel source supply, leading the SERC-Florida Peninsula with almost 75% of all generation served. SERC-Southeast will have an additional 2,200 MW of nuclear additions available to meet demand by 2023. SERC-East will be retiring 702 MW of nuclear and 2,228 MW of coal during the period. Overall, the assessment areas will undergo 13,147 MW of net additions and retirements within the next 10 years. Approximately 25 GW of utility-scale transmission BES-connected solar projects are expected in the interconnection queue over the next five years and are largely developing in SERC-East and SERC-Florida Peninsula. No reliability issues are expected within the assessment areas, but entities are continuing to monitor the impacts of solar generators as they are added to the interconnection queue. Entities are studying winter season impact of additional solar to the resource mix and load forecast. As more BTM solar generation is added, some entities anticipate becoming winter-peaking systems, providing additional motivation to enforce winter reserve margins.

Energy Storage

Entities in SERC are starting to see an increase in the number of energy storage system requests in their queues. In SERC-Central, there are firm plans to build a 20 MW battery energy storage system with an operational date of December 2023. Additionally, entities have reported they have contracted four solar plus battery storage projects, providing 180 MW (four hour duration) of additional battery storage, planned to be online between October of 2022 and September of 2023. Those batteries will be charged exclusively by the attached solar site and will be used to ensure that energy is reliable during periods of peak demand.

Entities in SERC-East have reported approximately 343 MW of potential electricity storage directly tied to the grid or to solar facilities in the next 5 years and an additional potential 850 MW in the next 10 years. Energy storage solutions (particularly batteries) continue to be viewed as an increasing necessity for the support of grid services, including frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e., solar and wind). Additionally, these battery resources can be used for providing capacity to defer new generation needs. For IRP purposes, the megawatts listed above provide capacity deferral and energy shifting benefits.

Many entities noted that energy storage is not integrated currently as a reduction to demand, meaning it is not treated as a DR program. Rather, utility-scale storage is charged from the system or from paired solar generation and is discharged onto the system to meet customer demand. In that respect, it acts as both a load and a generator, and the energy required to charge the battery is greater than the energy actually discharged by the battery onto the system since energy storage is not 100% efficient.

In SERC-Southeast, approximately 200 MW of electric storage resources are committed to come on-line in the next 5 years based on selections made in a request for proposal solicitations by an entity. The entity will pair both storage resources with solar as short-term capacity resources, one for smoothing and the other for day-ahead firming. Additional entities have reported that electric storage requests are awaiting study in their interconnection queues or are being evaluated as part of their integrated planning process.

In SERC-Florida Peninsula, electricity storage is still a growing capacity contributor. Over the next 10 years, approximately 500 MW of electricity storage generation is projected to come in-service and is included in the utilities' 10-year site plans. SERC-Florida Peninsula utilities have attributed a capacity contribution factor at time of peak that is unique to the structure of their units, adding to their reserve margin calculations. The first major installation of an energy storage unit is expected in Summer 2021, so no operating challenges have been identified yet. However, both the Florida Reliability Coordinating Council and the individual entities continue to monitor the situation to address any potential concerns.

Capacity Transfers

SERC members participate in the committee and study group structure to perform first contingency incremental transfer capability studies for the Regional Entity. These studies include evaluating transfer limitations between all assessment areas within the Regional Entity for the existing or planned system configuration and with normal (precontingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Annually, the SERC Long-Term Working Group performs a study to evaluate transfer capability for a summer peak condition in the planning period that covers year one through five. In addition, the SERC Near-Term Working Group performs two studies annually, prior to each upcoming seasonal peak (summer and winter). For a SERC study, SERC and regional member staffs apply a selection of transfers in pairs of varying magnitudes and directions non-simultaneously to a model with expected base transfers. The study's objective is to identify transmission system weaknesses, not necessarily to evaluate whether the transfer itself could actually happen. The model is coordinated through the SERC and Multi-regional Modeling Working Group model building processes and includes projections for generation dispatch, transmission system topology, system demand, and approved transmission uses. For each transfer, N-1 events for the entity and its neighbors are evaluated and monitored.

Transmission

Across the SERC Regional Entity, registered entities continue to build transmission, especially in the first five years of the assessment period, to ensure a reliable interconnected power system. SERC entities are expecting a total of 795 miles (i.e., 535 miles of >100 kV and 260 miles of >200 kV) of transmission additions over the period. Many of these projects are in the design/construction phase and are projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers (i.e., 345/138 kV and 161/500 kV), reconductoring existing transmission lines, and other system reconfigurations/additions to support transmission system reliability.

Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability. However, some localized constraints exist under certain contingency situations in SERC-East and SERC-Central, where existing operating guides are coordinated to mitigate the potential overload and remain reliable.

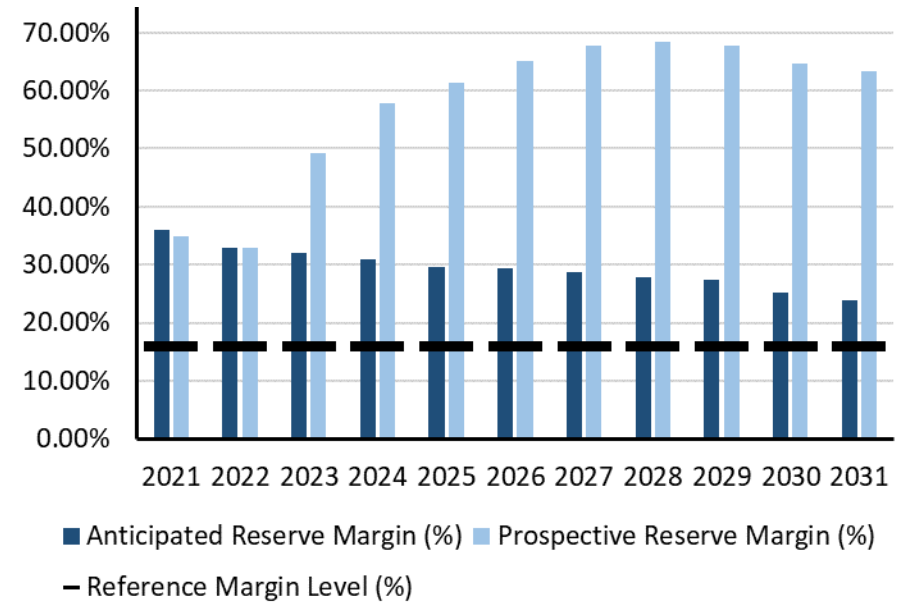
Transmission and operational limitations exist near multiple generation sites in SERC-Central due to line loading and transfers on the 161 kV transmission system. To maintain reliability and mitigate around these constraints, must run units will operate during specific load levels or redispatching generation to reduce line loading and transfer issues.

Reliability Issues

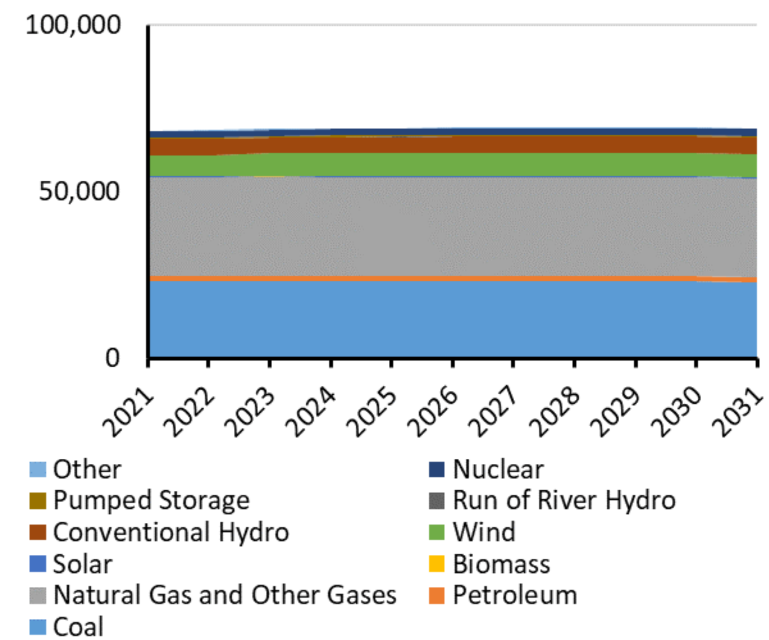
SERC entities have not identified any other emerging reliability issues that do not have existing operating guides. However, entities continue to monitor the possible impacts on the long-term reliability of the BES from the changing resource mix, extreme weather, and the higher penetration of VERs.

Entities in SERC-Central have studied a peak summer demand/low hydro scenario to reflect drought weather conditions. Planning has identified projects to address the more severe reliability concerns.

Demand, Resources, and Reserve Margins (MW)										
Quantity	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Internal Demand	51,911	52,817	53,335	53,978	54,299	54,602	54,947	55,208	56,166	56,437
Demand Response	729	838	870	920	994	1,009	1,021	1,027	1,033	1,026
Net Internal Demand	51,181	51,979	52,465	53,058	53,306	53,593	53,926	54,182	55,133	55,411
Additions: Tier 1	85	560	685	685	873	873	873	873	873	873
Additions: Tier 2	573	9,499	14,611	17,426	19,512	21,461	22,379	22,379	22,379	22,379
Additions: Tier 3	0	145	202	202	202	202	202	202	202	202
Net Firm Capacity Transfers	-329	-252	-252	-207	-188	-246	-241	-241	-242	-242
Existing-Certain and Net Firm Transfers	67,968	68,060	68,022	68,089	68,141	68,088	68,122	68,136	68,135	67,795
Anticipated Reserve Margin (%)	32.96%	32.02%	30.96%	29.62%	29.47%	28.67%	27.94%	27.37%	25.17%	23.92%
Prospective Reserve Margin (%)	33.02%	49.24%	57.76%	61.43%	65.05%	67.70%	68.43%	67.66%	64.76%	63.32%
Reference Margin Level (%)	16.00%	16.00%	16.00%	16.00%	16.00%	16.00%	16.00%	16.00%	16.00%	16.00%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- ARMs do not fall below the Reference Margin Level for the assessment period.
- Since the *2020 LTRA*, more than 1,500 MW of nameplate capacity has been retired in SPP. New generation that has become operational over the past year has mainly been wind resources.

SPP Fuel Composition (MW)										
Fuel	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Coal	23,047	23,047	22,989	22,989	22,989	22,989	22,989	22,989	22,989	22,647
Petroleum	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672	1,672
Natural Gas	29,787	29,788	29,788	29,788	29,788	29,788	29,788	29,788	29,787	29,787
Biomass	26	26	26	26	26	26	26	26	26	26
Solar	115	183	190	190	190	190	190	190	190	190
Wind	6,419	6,825	6,928	6,928	7,116	7,116	7,116	7,116	7,116	7,116
Conventional Hydro	4,814	4,823	4,844	4,865	4,898	4,903	4,923	4,938	4,938	4,939
Run of River Hydro	15	15	15	15	15	15	15	15	15	15
Pumped Storage	440	440	440	440	440	440	444	444	444	444
Nuclear	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947	1,947
Other	283	283	283	283	283	283	283	283	283	283
Total MW	68,564	69,049	69,121	69,143	69,363	69,368	69,392	69,407	69,406	69,066

SPP Assessment

The ARMs do not fall below the Reference Margin Level of 16% (SPP coincident) for the entire 10-year assessment period. The Reference Margin Level is determined by a probabilistic LOLE study. The SPP assessment area performs a biennial LOLE study to establish PRMs. Determination of the PRM is supported by a probabilistic LOLE study, which will analyze the ability to reliably serve the SPP BA area's 50/50 forecasted peak demand by utilizing a security-constrained economic dispatch. SPP, with input from the stakeholders, develops the inputs and assumptions used for the LOLE study. SPP will study the PRM such that the LOLE for the applicable planning year (two- and five-year study) does not exceed one day in ten years, or 0.1 day per year. At a minimum, the PRM will be determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand through the application of load uncertainty to ensure the LOLE does not exceed 0.1 day per year.

SPP load peaks during the summer season; the 2021 load forecast is projected to peak at 50,986 MW, which is projected to decrease compared to the previous year's LTRA forecast for the 2020 summer season. The coincident peak for the SPP assessment area is projected to decrease based on the member-submitted peak forecast being lower than the previous year along with approximately 250 MW of load transferring to ERCOT. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment time frame. The current annual growth rate is approximately 0.1%.

SPP's EE and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area.

SPP currently has approximately 250 MW of installed solar generating facilities. The SPP Model Development, Economic Studies, and the Supply Adequacy working groups are currently developing policies and procedures around DERs. The SPP Resource Adequacy Working Group implemented policies for DERs in 2020 that require certain testing, reporting, and documents for resources and programs not registered in the SPP integrated market.

Since the *2020 LTRA*, more than 1,500 MW of nameplate capacity has been retired in SPP. The generation that has been retired over the past year has mainly been replaced with wind resources. The impact of retirements to resource adequacy is assessed in the LOLE study. Currently, SPP is not expecting any long-term reliability impacts resulting from generating plant retirements, but will evaluate these impacts in the 2021 LOLE study.

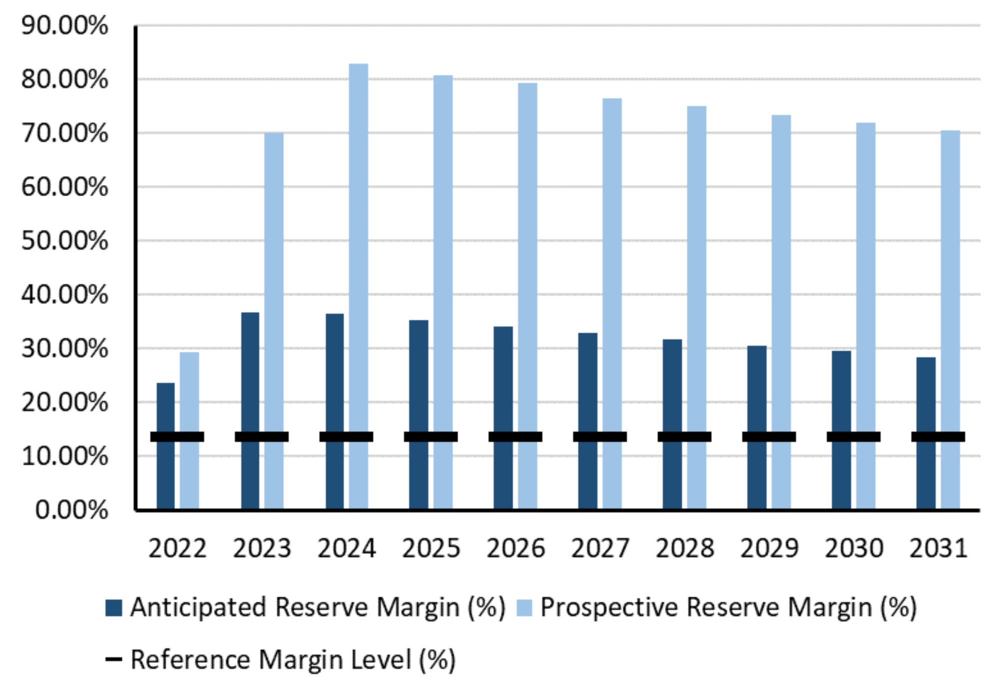
The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis during the model build season, SPP staff coordinates the modeling of transfers between PC footprints. The modeled transactions are fed into the models created for the SPP planning process.

During April 2019, SPP and ERCOT executed a coordination plan that superseded the prior coordination agreement. The coordination plan addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers, and switchable generation resources. Under the terms of the coordination plan, SPP has priority to recall the capacity of any switchable generation resources that have been committed to satisfy the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff.

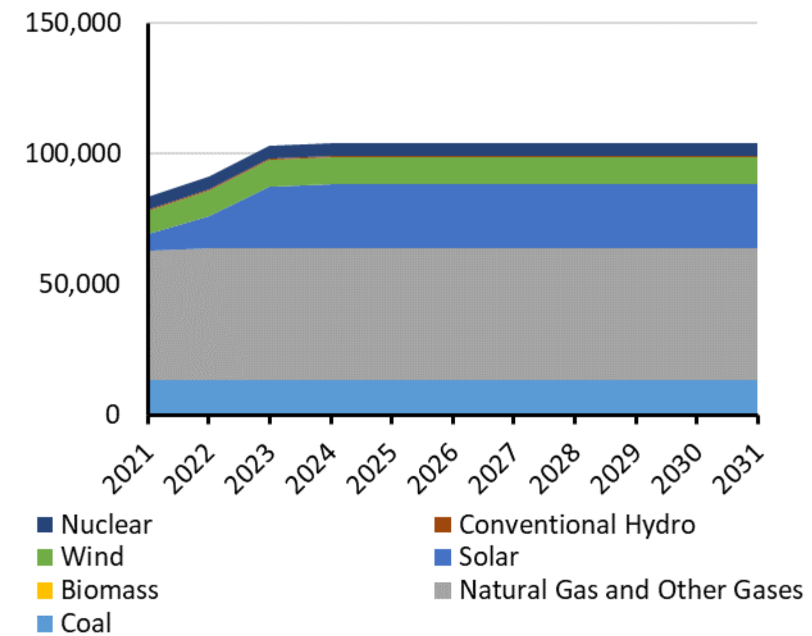
Annually, SPP and ERCOT update the coordination plan based on the latest discussions and business decisions.

The SPP board of directors approved the *2020 Integrated Transmission Plan Assessment* and the *2020 SPP Transmission Expansion Plan Report*. Both reports provide details for proposed transmission projects needed to maintain reliability while also providing economic benefit to the end users.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	78,665	80,000	80,907	81,632	82,354	83,076	83,782	84,481	85,179	85,861
Demand Response	2,033	2,033	2,033	2,033	2,033	2,033	2,033	2,033	2,033	2,033
Net Internal Demand	76,633	77,968	78,875	79,599	80,322	81,043	81,749	82,449	83,146	83,828
Additions: Tier 1	12,075	23,927	25,031	25,031	25,031	25,031	25,031	25,031	25,031	25,031
Additions: Tier 2	4,696	26,420	37,041	37,503	37,666	37,666	37,666	37,666	37,666	37,666
Additions: Tier 3	4,378	15,856	25,005	29,021	29,141	29,141	29,141	29,141	29,141	29,141
Net Firm Capacity Transfers	210	210	210	210	210	210	210	210	210	210
Existing-Certain and Net Firm Transfers	82,764	82,719	82,672	82,675	82,678	82,681	82,679	82,682	82,685	82,688
Anticipated Reserve Margin (%)	23.76%	36.78%	36.55%	35.31%	34.10%	32.91%	31.76%	30.64%	29.55%	28.50%
Prospective Reserve Margin (%)	29.38%	70.17%	83.02%	80.86%	79.44%	76.52%	74.99%	73.51%	72.06%	70.66%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Texas RE-ERCOT’s ARM is above the Reference Margin Level (13.75%) throughout the assessment period. The ARM increases significantly for the summers of 2022 and 2023 due to the expected addition of nearly 20,000 MW of new capacity, most of which is solar generation.
- The continuing penetration of wind and solar is increasing the risk of tight operating reserves during hours other than the daily peak load hour. This issue is most acute for the summer season, but the spring can also be impacted since this is the peak unit maintenance season when planned outages are at their highest for the year.
- In the wake of the February 2021 cold weather event, new state legislation institutes grid and institutional reforms to address extreme weather events. Additionally, ERCOT and its market participants are managing corrective actions that cover inter-industry coordination, emergency preparedness/communications, market design, weatherization, identification of critical natural gas facilities, and generator performance, among others.

Texas RE-ERCOT Fuel Composition (MW)										
Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568
Natural Gas	50,198	50,198	50,198	50,198	50,198	50,198	50,198	50,198	50,198	50,198
Biomass	163	163	163	163	163	163	163	163	163	163
Solar	12,533	23,397	24,501	24,501	24,501	24,501	24,501	24,501	24,501	24,501
Wind	9,462	10,451	10,451	10,451	10,451	10,451	10,451	10,451	10,451	10,451
Conventional Hydro	474	474	474	474	474	474	474	474	474	474
Nuclear	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973
Total MW	91,371	103,223	104,327	104,327	104,327	104,327	104,327	104,327	104,327	104,327

Texas RE-ERCOT Assessment

Planning Reserve Margins

The summer ARM is above the Reference Margin Level (13.75%) for the first five years of the assessment period (2021–2025). The ARM increases significantly for the summers of 2022 and 2023 due to the expected addition of 19,579 MW of Tier 1 capacity additions, most of which is solar.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

The continuing penetration of wind and solar is increasing the risk of tight operating reserves during hours other than the daily peak load hour. This issue is most acute for the summer season, but the spring can also be impacted since this is the peak unit maintenance season when planned outages are at their highest for the year. To examine this risk more closely, there were evaluations of the seasonal occurrences of low levels of frequency-responsive operating reserves for each hour. This retrospective analysis was intended to supplement the summer 2021 probabilistic loss of load study conducted for the *NERC 2021 Summer Reliability Assessment*. The study indicated that the hour endings 3:00–6:00 p.m. local time had the highest summer operating reserves risk for the last several years. These findings help refine the scope of energy assurance risk assessment and associated analysis tools.

Finally, ERCOT continues to refine the probabilistic version of its seasonal assessment of resource adequacy report, which calculates the risk of insufficient "capacity available for operating reserves" for a range of hours on the expected summer peak load day.

Demand

Forecasted compound annual growth rate for summer peak demand for 2021–2030 is 1.2%. This is lower than the previous forecast that included a 1.6% compound annual growth rate for 2020–2029. This reduction is not surprising due to the lingering impacts of COVID-19 on the Texas economy. Summer peak demand for the western-most weather zone (which encompasses the metropolitan area of Odessa and Midland) is projected to increase by 3.1% over the same time period. This increase reflects continued robust oil and natural gas exploration activity in this area (though this growth is less than last year, which was 3.9%). The peak demand for the North weather zone, which includes the cities of Lubbock and Wichita Falls, is projected to only marginally increase. This area appears to be lagging in economic growth compared to the rest of Texas RE-ERCOT.

Demand Side Management

Most of the demand-side resources available are dispatchable in the form of "non-controllable load resources providing responsive reserve service" and procured and deployable emergency resources, referred to in this section as ERCOT ERS. Responsive reserves is an ancillary service for controlling system frequency. It is provided by industrial loads and is procured on an hourly basis in the day-ahead market. Reserves are dispatched by automatic trip based on under-frequency relay settings (59.7 Hz) or manual dispatch instruction within 10 minutes. ERCOT ERS consists of 10-minute and 30-minute ramp DR and distributed generation designed to be deployed in the late stages of a grid emergency prior to shedding involuntary firm load. It is procured for three four-month periods per year. ERCOT ERS may be deployed at any time once an energy emergency alert is declared. The remaining dispatchable DR available is from the transmission and distribution service provider's load management programs. These programs provide price incentives for voluntary load reductions from commercial, industrial (and most recently) residential loads during energy emergency alert events. These programs are available for the months of June through September from 1:00–7:00 p.m. local time weekdays (except holidays) and are deployed concurrently with ERCOT ERS via instruction pursuant to agreements between ERCOT and the transmission and distribution service providers.

Distributed Energy Resources

The formal definition of distributed generation is as follows: an electrical generating facility located at a Customer's point of delivery (point of common coupling) 10 MW or less and connected at a voltage less than or equal to 60 kV that may be connected in parallel operation to the utility system. Distributed generators include energy storage resources as well. Over the last few years, ERCOT has instituted a new generation resource taxonomy. Distributed generators are now distinguished by whether they are transmission or distribution-connected, whether they fully participate in the ERCOT market or just get paid for exported energy (settlement-only generators), and whether they are registered or not registered with ERCOT. Distributed generators that register are modelled and dispatched in transmission planning studies similarly to transmission-connected resources. For DERs not participating in those markets, ERCOT relies on member transmissions/distribution service providers to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one- to six-year time frame.

Currently in use is a logistic (or "S-curve") technology penetration model for forecasting the growth of rooftop solar capacity. The actual year-end quantity of rooftop solar PV reported for 2020 matched the moderate growth scenario projection, so that curve was used for the 5- and 10-year growth projections reported in the LTRA. For the moderate scenario, the installed capacity by 2030 is 5,861 MW. To estimate the capacity contribution of rooftop PV during summer and winter peak load hours, ERCOT used hourly output profiles for years 2017–2020 developed by a contractor for urban/rural rooftop PV sites throughout Texas RE-ERCOT.

Generation

Capacity growth is expected to be dominated by solar for at least the next two to three years, and as solar installed capacity increases, there will be larger solar ramps due to diurnal solar patterns and climatological variations, leading to more instances where regulation service is exhausted. In anticipation of this growth in the solar fleet beginning June 1, 2021, ERCOT incorporated an intra-hour solar forecast into the dispatch process to obtain non-wind, non-solar resources in anticipation of solar ramps. This change will take the burden off regulation service to cover the five-minute gain or loss of generation resulting from variations in solar irradiance. This change will also aid in reducing frequency recovery duration following events that occur during times with significant solar up and down ramps. ERCOT incorporated a similar intra-hour wind forecast into the dispatch process in December 2018.

ERCOT is currently conducting several transmission planning studies directly related to increasing renewable penetration on the system. The ongoing South Texas Stability Assessment is evaluating the stability-related needs for the Lower Rio Grande Valley area, which is subject to both import constraints under peak load conditions and export constraints under high IBR output conditions. The ongoing Long-Term West Texas Export Special Study is evaluating potential transmission improvements to increase transfer capability from renewable-rich areas in West Texas to urban demand centers further east. Transfers from West Texas are currently limited by both voltage and dynamic stability constraints as well as thermal constraints closer to demand centers.

Energy Storage

There are currently 552 MW of installed energy storage resources that are modeled in ERCOT systems. This number includes 295 MW that are synchronized to the grid but not yet approved for commercial operations by ERCOT. The majority of the installed energy storage projects have limited duration energy capability. The amount of battery energy storage capacity is expected to increase dramatically over the next several years. A large portion of these energy storage resources are expected to participate in the ancillary services market, specifically to provide responsive reserve service, which is a frequency response type of ancillary service. ERCOT is in the process of hiring a vendor to conduct studies to investigate and determine if there are reliability reasons that require them to establish limits on the amount of responsive reserve service that can be provided by a single resource or a group of resources of a technology type.

Capacity Transfers

ERCOT coordinates with neighboring grids through coordination plans, last updated in 2019, that cover dc tie emergency operations, procedures for generators that can switch between grids, and block load transfers (groups of loads that are transferred to a neighboring grid for service on a temporary basis).

The most noteworthy development was the October 2020 retirement of the Oklaunion coal-fired plant. This plant served firm contracts in SPP via the ERCOT North dc tie. Since all the firm contracts associated with the plant have terminated, ERCOT is now able to curtail the tie exports to zero MW in an emergency condition instead of having to honor exports associated with firm transactions. Otherwise, tie flows with SPP have not been materially impacted by the Oklaunion retirement.

Transmission

The recently updated ERCOT Transmission Project and Information Tracking List (March 2021) includes the addition or upgrade of 2,147 circuit miles of 138-kV and 345-kV transmission circuits and 13,807 MVA of 345/138 kV transformer capacity that are planned between 2021 and 2026.

The Delaware Basin comprises an eight-county area in West Texas and is experiencing much of the aforementioned load growth. In 2019, a five-stage roadmap for potential 345 kV transmission improvements that may be needed to support continued load growth in the Delaware Basin was completed. Forecasted peak demand for the Delaware Basin will surpass the level identified for the first stage of improvements identified in the Delaware Basin Load Integration Study by Summer 2023. A second 345 kV circuit from Bakersfield Station to Big Hill Station with connections at Cedar Canyon Station, Noelke Station, and Schneeman Draw Station is recommended, currently under review, and projected to be in-service prior to the 2023 summer peak.

The Freeport area, south of Houston and adjacent to the Gulf of Mexico, is highly industrialized. Several industrial load additions, including the Freeport LNG export facility, are either under construction or have been proposed. Transmission projects, totaling $117 million, have already been completed in 2016 and 2017. In December 2017, the Freeport Master Plan project was approved. Among other improvements, the project will add a 48-mile 345 kV double-circuit transmission line from Bailey to Jones Creek, which is expected to be in-service by the end of 2021.

There are over 1,000 MW of expected industrial load additions under construction in the Corpus Christi North Shore area. In June 2020, the Corpus Christi North Shore Transmission Improvement Project was approved to meet reliability needs resulting from these load additions. Planned improvements include a new 345-kV Angstrom substation looped into the 345 kV transmission line from Whitepoint to STP, a new 345/138 kV Naismith substation, two new 345/138 kV transformers at Naismith, an additional 345/138 kV transformer at Whitepoint, approximately 36 total miles of new

345 kV transmission lines from Angstrom to Grissom and from Angstrom to Naismith, and approximately 28 circuit miles of 138 kV transmission line additions and upgrades. All these upgrades are expected to be in-service prior to the 2024 summer peak.

Reliability Issues

The Texas Panhandle area is continuing to experience significantly more interest from wind and solar generation developers than what was initially planned for the area. Stability challenges and weak system strength are expected to continue to be significant constraints for Panhandle export. The additional export circuit associated with the integration of Lubbock Power & Light into ERCOT is expected to alleviate some of the congestion.

West Texas has experienced rapid growth in IBRs. Voltage and dynamic stability constraints associated with large-scale power transfers from West Texas to urban demand centers further east are expected to continue. ERCOT has implemented a generic transmission constraint to manage stability limits in operations and is conducting a Long-Term West Texas Export Special Study to evaluate potential transmission improvements to cost-effectively mitigate the constraints.

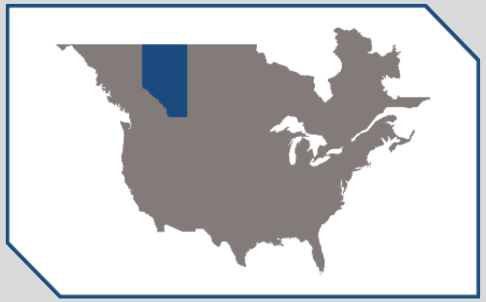
South Texas, including the Lower Rio Grande Valley, has also experienced substantial wind and solar generation development activity. Transmission reliability studies have identified multiple stability constraints within the South Texas area. Generic transmission constraints are used to manage stability limits in operations. As generation development continues in the area, ERCOT will perform system reliability analysis, evaluate tools to manage the constraints, and evaluate transmission projects to cost-effectively mitigate the constraints.

Winter Storm Uri

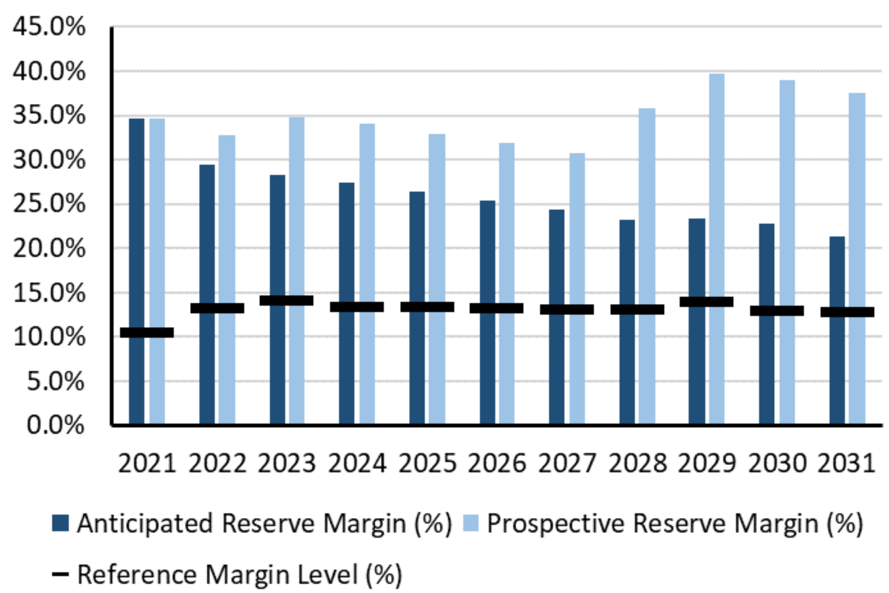
There was a historic loss of generation during winter storm Uri (February 14–20, 2021). The causes and time line for the loss of generation are documented in a public report.[61]

In addition to new legislation recently signed into Texas law that institutes grid and institutional reforms to address extreme weather events, ERCOT and its market participants are managing an "emergency actions list"[62] comprised of 124 action items that cover inter-industry coordination, emergency preparedness/communications, procedural reviews for operations and financial settlements, market design, weatherization, identification of critical natural gas facilities, generator performance, and many others.

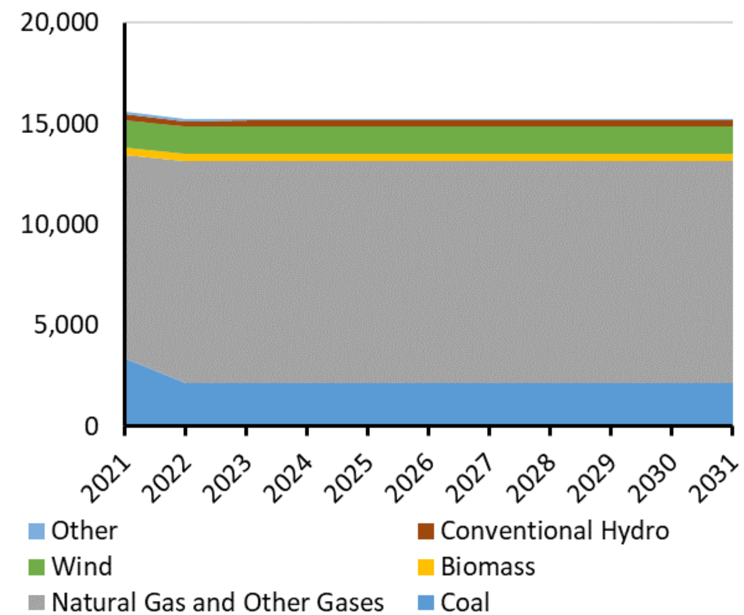
[61] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf
[62] http://www.ercot.com/content/wcm/key_documents_lists/27308/Emergency_Conditions_List_052821.xlsx



WECC-NWPP-AB Demand, Resources, and Reserve Margins (MW)										
Quantity	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Internal Demand	11,771	11,901	11,961	12,065	12,154	12,257	12,373	12,362	12,413	12,548
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,771	11,901	11,961	12,065	12,154	12,257	12,373	12,362	12,413	12,548
Additions: Tier 1	3,780	3,784	3,784	3,784	3,784	3,784	3,784	3,781	3,781	3,781
Additions: Tier 2	396	787	787	787	787	787	1,567	2,021	2,021	2,021
Additions: Tier 3	314	446	534	848	1,119	1,229	1,229	1,717	2,452	3,452
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	11,449	11,475	11,461	11,461	11,461	11,461	11,461	11,466	11,452	11,452
Anticipated Reserve Margin (%)	29.4%	28.2%	27.5%	26.4%	25.4%	24.4%	23.2%	23.3%	22.7%	21.4%
Prospective Reserve Margin (%)	32.7%	34.8%	34.0%	32.9%	31.9%	30.8%	35.9%	39.7%	39.0%	37.5%
Reference Margin Level (%)	13.2%	14.1%	13.4%	13.3%	13.2%	13.2%	13.1%	13.9%	12.9%	12.8%

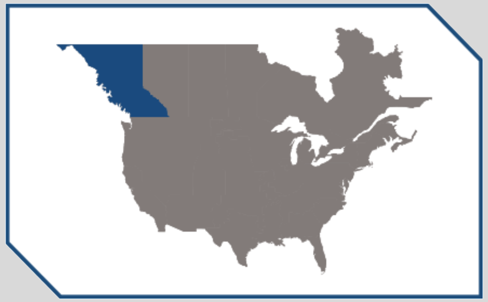


Planning Reserve Margins

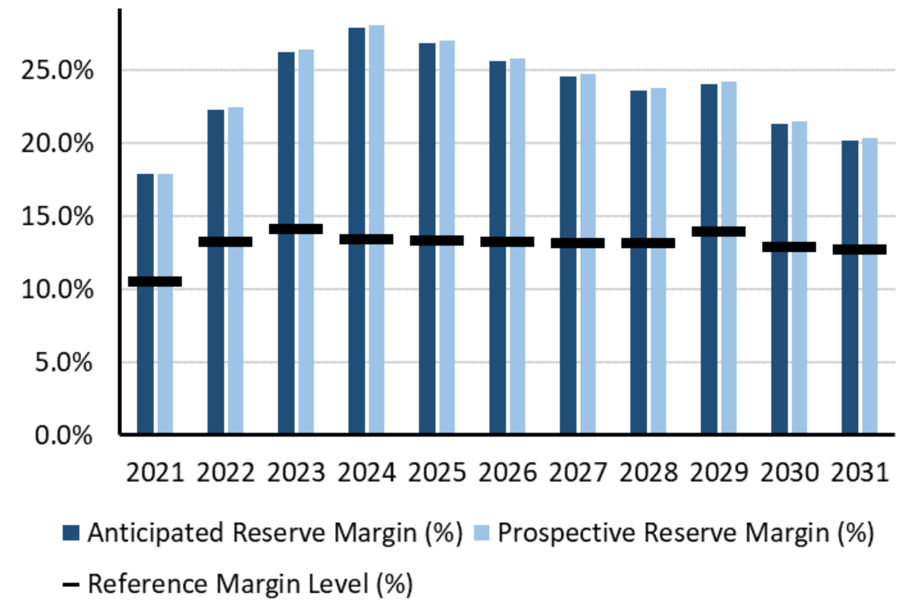


Existing and Tier 1 Resources

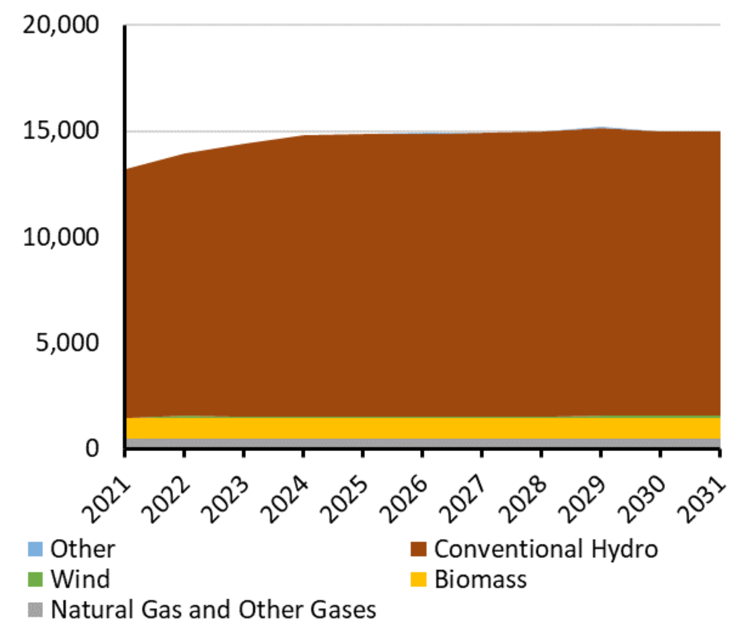
WECC-NWPP-AB Composition (MW)										
Fuel	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Coal	2,171	2,174	2,174	2,174	2,174	2,174	2,174	2,172	2,172	2,172
Natural Gas	10,978	10,991	10,991	10,991	10,991	10,991	10,991	10,982	10,982	10,982
Biomass	334	335	335	335	335	335	335	334	334	334
Wind	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361	1,361
Conventional Hydro	294	308	294	294	294	294	294	308	294	294
Other	91	91	91	91	91	91	91	91	91	91
Total MW	15,229	15,259	15,245	15,245	15,245	15,245	15,245	15,248	15,234	15,234



WECC-NWPP-BC Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	11,420	11,430	11,582	11,714	11,859	11,998	12,125	12,235	12,351	12,472
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,420	11,430	11,582	11,714	11,859	11,998	12,125	12,235	12,351	12,472
Additions: Tier 1	158	450	1,017	1,058	1,099	1,141	1,182	1,199	1,182	1,182
Additions: Tier 2	20	20	20	20	20	20	20	20	20	20
Additions: Tier 3	0	0	0	3	40	40	40	41	95	95
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	13,809	13,978	13,804	13,804	13,804	13,804	13,804	13,983	13,809	13,809
Anticipated Reserve Margin (%)	22.3%	26.2%	28.0%	26.9%	25.7%	24.6%	23.6%	24.1%	21.4%	20.2%
Prospective Reserve Margin (%)	22.5%	26.4%	28.1%	27.0%	25.8%	24.7%	23.8%	24.3%	21.5%	20.4%
Reference Margin Level (%)	13.2%	14.1%	13.4%	13.3%	13.2%	13.2%	13.1%	13.9%	12.9%	12.8%



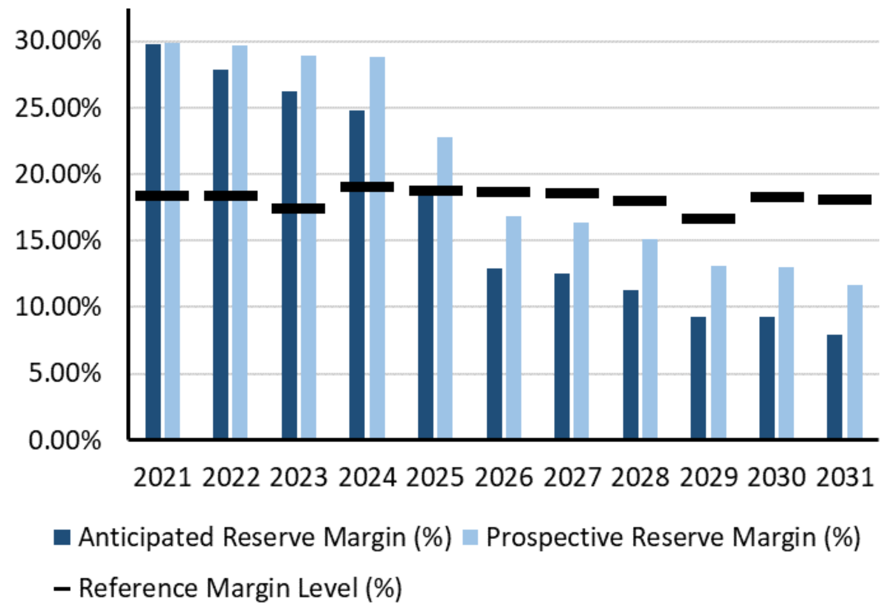
Planning Reserve Margins



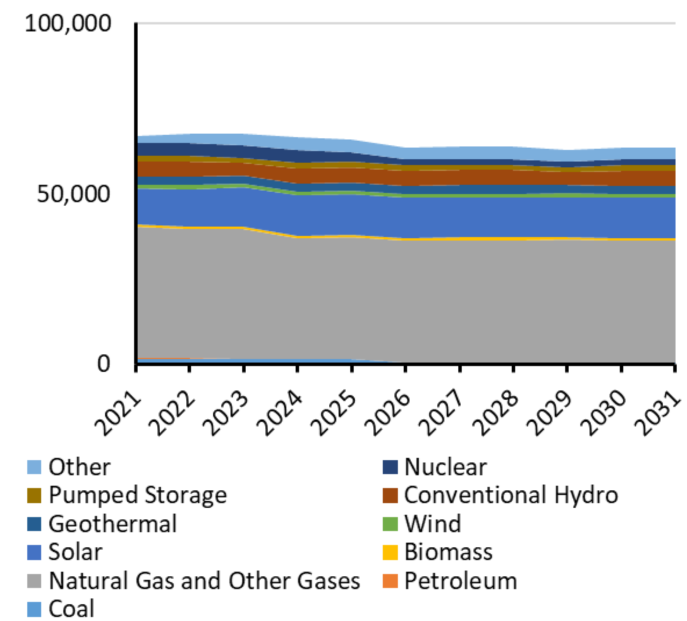
Existing and Tier 1 Resources

WECC-NWPP-BC Composition (MW)										
Fuel	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Natural Gas	450	448	448	448	448	448	448	450	450	450
Biomass	972	968	968	968	968	968	968	972	972	972
Wind	110	110	110	110	110	110	110	110	110	110
Conventional Hydro	12,413	12,880	13,272	13,313	13,354	13,395	13,437	13,628	13,437	13,437
Other	22	22	22	22	22	22	22	22	22	22
Total MW	13,967	14,428	14,821	14,862	14,903	14,944	14,986	15,182	14,991	14,991

WECC-CA/MX Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	55,790	56,186	57,123	57,693	58,278	58,591	59,115	59,271	59,833	60,405
Demand Response	928	928	928	928	928	928	928	928	928	928
Net Internal Demand	54,862	55,258	56,195	56,765	57,350	57,663	58,187	58,343	58,905	59,477
Additions: Tier 1	3,806	4,775	5,825	6,594	6,605	6,804	6,810	6,823	7,353	7,353
Additions: Tier 2	994	1,501	2,224	2,224	2,224	2,224	2,224	2,224	2,224	2,224
Additions: Tier 3	0	0	0	0	0	0	0	0	0	18,569
Net Firm Capacity Transfers	2,444	2,148	3,652	1,633	1,108	1,092	948	837	682	524
Existing-Certain and Net Firm Transfers	66,327	64,976	64,312	60,894	58,158	58,075	57,931	56,922	56,985	56,827
Anticipated Reserve Margin (%)	27.8%	26.2%	24.8%	18.9%	12.9%	12.5%	11.3%	9.3%	9.2%	7.9%
Prospective Reserve Margin (%)	29.6%	28.9%	28.8%	22.8%	16.8%	16.4%	15.1%	13.1%	13.0%	11.6%
Reference Margin Level (%)	18.4%	17.4%	19.0%	18.7%	18.6%	18.6%	18.0%	16.7%	18.2%	18.1%

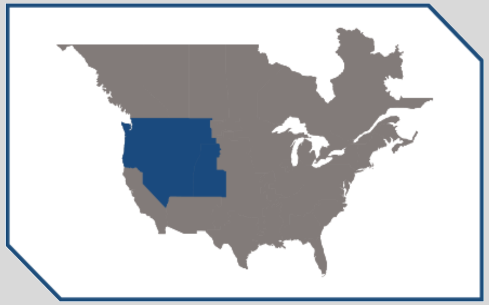


Planning Reserve Margins

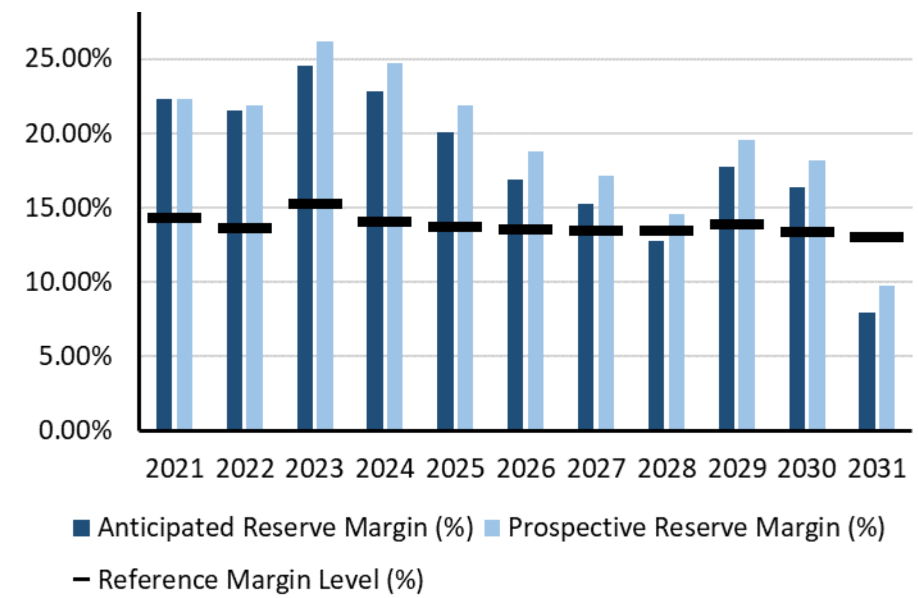


Existing and Tier 1 Resources

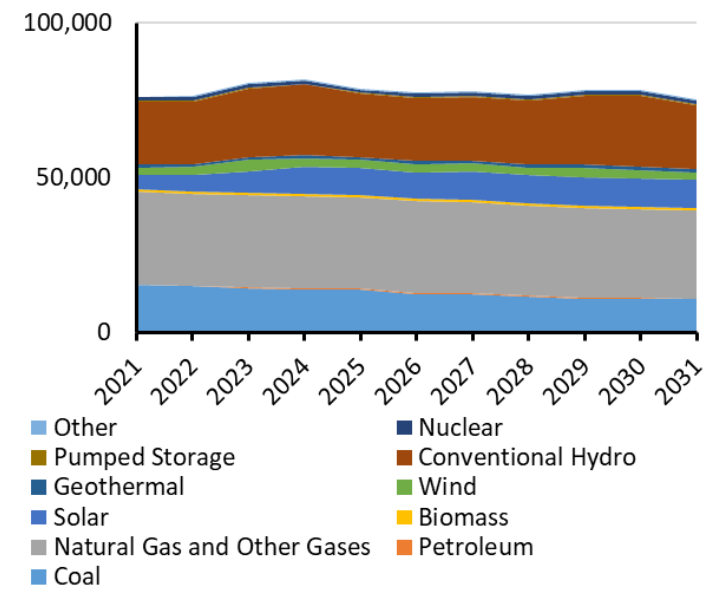
WECC-CA/MX Composition (MW)										
Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	1,646	1,592	1,592	1,592	487	487	487	487	487	487
Petroleum	80	80	80	80	80	80	80	80	80	80
Natural Gas	38,014	37,963	35,252	35,717	35,717	35,843	35,843	35,887	35,683	35,683
Biomass	729	728	728	728	728	728	728	729	729	729
Solar	10,921	11,450	11,780	11,791	11,801	11,807	11,813	11,820	11,826	11,826
Wind	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,105
Geothermal	2,441	2,439	2,439	2,439	2,439	2,439	2,439	2,443	2,443	2,443
Conventional Hydro	4,432	3,911	4,432	4,432	4,432	4,432	4,432	3,911	4,432	4,432
Pumped Storage	1,671	1,246	1,671	1,671	1,671	1,671	1,671	1,246	1,671	1,671
Nuclear	3,880	3,876	3,876	2,771	1,665	1,665	1,665	1,667	1,667	1,667
Other	2,769	3,212	3,529	3,529	3,529	3,529	3,529	3,532	3,532	3,532
Total MW	67,690	67,603	66,485	65,856	63,655	63,786	63,793	62,907	63,656	63,656



WECC-NWPP & RMRG Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	70,393	71,775	72,955	73,410	73,843	74,476	75,136	75,671	76,191	76,803
Demand Response	1,336	1,340	1,344	1,352	1,354	1,355	1,352	1,353	1,359	1,360
Net Internal Demand	69,058	70,435	71,611	72,058	72,490	73,121	73,784	74,317	74,831	75,443
Additions: Tier 1	2,335	4,531	6,095	5,992	5,993	6,636	6,700	6,844	6,873	6,698
Additions: Tier 2	254	1,177	1,350	1,324	1,324	1,324	1,324	1,345	1,349	1,325
Additions: Tier 3	180	306	2,620	2,575	2,739	2,739	2,918	3,680	5,439	5,399
Net Firm Capacity Transfers	7,556	7,008	6,096	7,655	7,317	6,425	6,447	9,180	8,701	6,280
Existing-Certain and Net Firm Transfers	81,560	83,180	81,867	80,517	78,760	77,664	76,496	80,658	80,214	74,751
Anticipated Reserve Margin (%)	21.5%	24.5%	22.8%	20.1%	16.9%	15.3%	12.8%	17.7%	16.4%	8.0%
Prospective Reserve Margin (%)	21.9%	26.2%	24.7%	21.9%	18.7%	17.1%	14.5%	19.6%	18.2%	9.7%
Reference Margin Level (%)	13.6%	15.2%	14.0%	13.7%	13.5%	13.4%	13.4%	13.8%	13.4%	13.0%

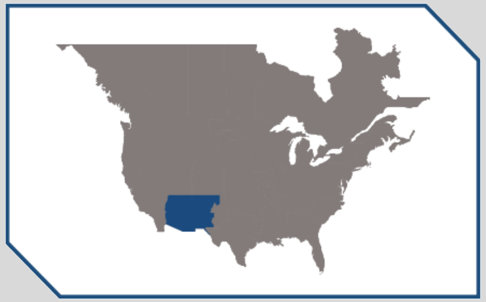


Planning Reserve Margins

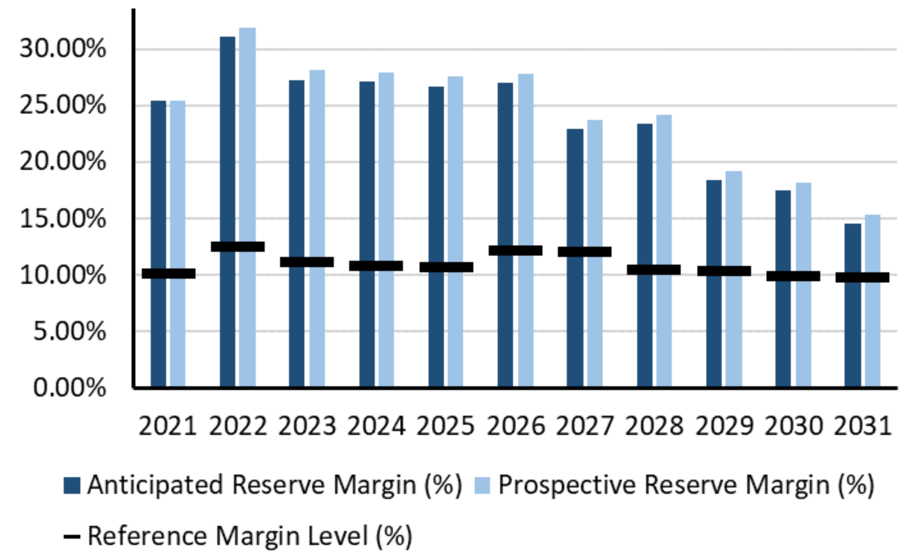


Existing and Tier 1 Resources

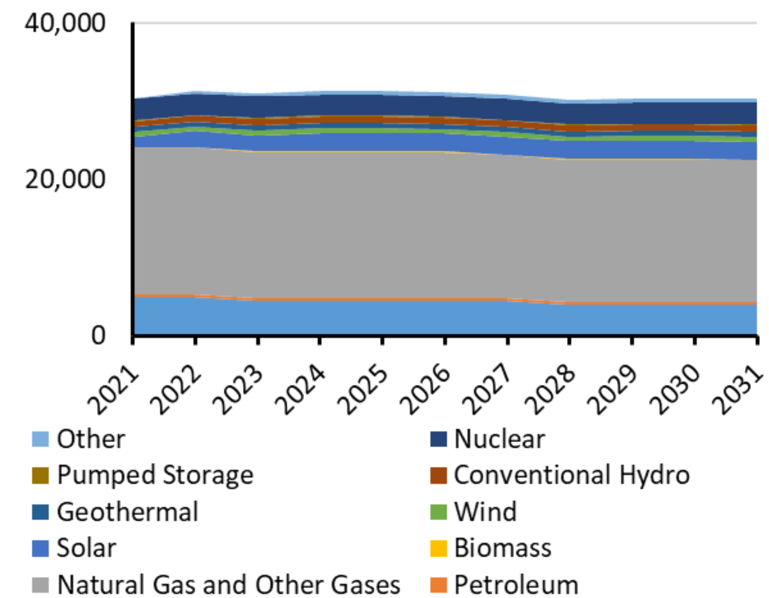
WECC-NWPP & RMRG Composition (MW)										
Fuel	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Coal	14,838	14,348	13,826	13,818	12,489	12,489	11,641	10,951	10,700	10,591
Petroleum	277	276	276	275	275	275	275	276	276	277
Natural Gas	29,751	29,799	29,791	29,646	29,557	29,353	29,011	28,981	28,710	28,483
Biomass	784	785	784	779	779	779	779	784	784	784
Solar	5,247	6,699	8,797	8,632	8,632	9,057	9,057	9,240	9,240	9,057
Wind	2,560	3,797	2,839	2,566	2,566	2,566	2,566	2,846	2,846	2,566
Geothermal	887	974	1,014	1,022	1,022	1,022	1,086	1,078	1,078	1,080
Conventional Hydro	20,383	22,275	22,777	20,402	20,403	20,622	20,622	22,420	22,992	20,605
Pumped Storage	326	347	359	326	326	326	326	345	359	326
Nuclear	1,095	1,099	1,097	1,081	1,081	1,081	1,081	1,097	1,097	1,097
Other	191	305	304	306	306	306	306	304	304	304
Total MW	76,339	80,703	81,865	78,853	77,436	77,875	76,749	78,322	78,386	75,169



WECC-SRSG Demand, Resources, and Reserve Margins (MW)										
Quantity	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Internal Demand	25,203	25,445	25,742	26,113	26,690	27,155	27,512	27,920	28,340	28,684
Demand Response	392	395	388	407	317	365	368	361	347	317
Net Internal Demand	24,811	25,050	25,354	25,706	26,373	26,790	27,144	27,559	27,993	28,367
Additions: Tier 1	1,471	1,858	2,156	2,156	2,131	2,131	2,115	2,156	2,156	2,156
Additions: Tier 2	214	215	215	215	214	214	210	215	215	215
Additions: Tier 3	201	1,977	2,562	3,159	3,560	3,865	4,213	4,866	5,301	5,967
Net Firm Capacity Transfers	1,128	800	857	1,201	2,289	2,101	3,261	2,259	2,501	2,194
Existing-Certain and Net Firm Transfers	31,039	30,015	30,066	30,410	31,363	30,784	31,375	30,481	30,716	30,324
Anticipated Reserve Margin (%)	31.0%	27.2%	27.1%	26.7%	27.0%	22.9%	23.4%	18.4%	17.4%	14.5%
Prospective Reserve Margin (%)	31.9%	28.1%	27.9%	27.5%	27.8%	23.7%	24.2%	19.2%	18.2%	15.3%
Reference Margin Level (%)	12.4%	11.1%	10.8%	10.7%	12.2%	12.0%	10.4%	10.3%	9.8%	9.7%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-SRSG Composition (MW)										
Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	5,023	4,428	4,428	4,428	4,422	4,422	3,926	3,925	3,925	3,925
Petroleum	319	318	318	318	318	318	319	319	319	319
Natural Gas	18,729	18,774	18,774	18,774	18,748	18,358	18,289	18,276	18,276	18,193
Biomass	81	81	81	81	81	81	81	81	81	81
Solar	2,022	2,068	2,322	2,322	2,311	2,311	2,252	2,322	2,322	2,320
Wind	559	601	601	601	559	559	584	601	601	601
Geothermal	686	684	684	684	685	685	686	686	686	686
Conventional Hydro	747	831	823	823	747	747	754	831	823	823
Pumped Storage	107	107	108	108	107	107	107	107	108	108
Nuclear	2,724	2,714	2,714	2,714	2,712	2,712	2,716	2,717	2,717	2,717
Other	385	469	513	513	514	514	515	514	514	514
Total MW	31,382	31,073	31,365	31,365	31,204	30,814	30,229	30,378	30,372	30,287

WECC Assessment

Highlights

- Declining reserve margins in WECC CA/MX are due in part to the peak demand hour occurring later in the day when solar PV resource output is lower and with the planned retirement of the Diablo Canyon Power Plant nuclear generators in 2025. Probabilistic energy analysis indicates 10 potential hours of load loss in 2022. Flexible resources that can be dispatched to counter solar PV behavior and be relied upon in extreme conditions are needed to reduce the load-loss risk and serve energy in all seasons and time periods.
- The U.S. Northwest and Southwest part of WECC (NWPP-US & RMRG and SRSG) have increasingly variable demand and resource profiles, raising the risk of energy shortfalls. Energy analysis indicates the potential for 23 load-loss hours in the Northwest in 2022. The Southwest faces potential load-loss hours in 2024. As resource planners in parts of the Western Interconnection turn increasingly to external transfers for resource adequacy, the need for regional coordination and planning is growing.
- ARMs in the Canadian assessment areas of WECC are above RMLs throughout the assessment period.

WECC-NWPP-AB

New this year when compared to last year's LTRA is that the Alberta assessment area has confirmed the retirements of many of their coal resources. This causes the existing certain reserve margin to be short of the Reference Margin Level in all seasons starting in 2022. However, plans have been in place to replace and/or convert these resources with natural gas resources. With Tier 1 and 2 resources, the assessment area is well above the calculated Reference Margin Level needed to maintain a 1-day-in-10-year level of reliability for the given hour represented in each season of this assessment. Alberta is expected to continue being a winter-peaking area. With the majority of their portfolio being baseload resources, natural gas resources in particular, WECC is not concerned with any risk due to variability of demand or variable resources.

WECC-NWPP-BC

The British Columbia assessment area shows little change from last year's LTRA. This area continues to be a winter-peaking demand area that is served mainly by conventional storage-capable hydro resources. Relying on existing resources only, the assessment area is expected to be short of the calculated reserve margin beginning the winter of 2030; however, plans are in place to increase the hydro capacity by then, and this will be sufficient to meet any demand growth they are expecting. With the storage capable technology, WECC is not concerned with this area's ability to meet variability in demand and or resources. The only potential issue would be on the continuing drought conditions experienced lately, causing less fuel availability for the hydro resources; however, this has not had a significant impact to date. WECC will continue monitoring the drought conditions for fuel availability.

WECC-CA/MX

Planning Reserve Margins

The CA/MX assessment area is significantly short of the calculated reserve margin needed to maintain a 1-day-in-10-year level of reliability beginning in 2026 and extending through the remainder of the assessment period. One contributing factor in this shortfall is the apparent change in peak demand hour to later in the afternoon, as discussed in the following section, and the lower output of solar resources that corresponds with this later peak period.

With existing resources, the area falls sort of the Reference Margin Level for the peak hour beginning in the summer of 2024. With new resources planned to be on-line by then, the shortfall from the Reference Margin Level is pushed out to the summer of 2026. There may be more transfers available from all areas to mitigate this shortfall when all areas are incorporating their prospective resources as well. However, due to reporting form constraints, WECC is only reflecting the results from the model run with Tier 1 and 2 resources for import capabilities.

WECC is planning discussions with the balancing areas in the CA/MX subregion to mitigate this risk in 2026. The shift in peak demand hours highlights the importance of representing all hours in a reliability assessment. WECC will continue to use the probabilistic assessment results to work with the areas to highlight all risks.

Demand

CA/MX experienced a shift in the expected peak hour demand. In previous LTRAs, the peak hour for demand was expected to occur at hour beginning 3:00 p.m. local time. This year's LTRA represents the peak hour for demand one hour later at hour beginning 4:00 p.m. local time. This is significant as it has an impact on the expected solar availability when viewing 3:00 p.m. vs. 4:00 p.m. local time.

Historical analysis shows continuing penetrations of BTM solar generation is shifting the demand profile. WECC uses historical profiles to shape forecasted demand into hourly expectations. Given this shift in profiles, it is no longer prudent to use any historical profile older than a few years. WECC continues using the last year as the profile for hourly demand. This is more accurate but causes more variability year on year as a longer period average would smooth out the variance in year to year profiles.

Since the pandemic caused demand profiles to shift, WECC determined some of the impact will continue and some demand will return closer to pre-pandemic patterns. Therefore, WECC used 2019 and 2020 load profiles for this assessment. The expected peak demand hour shift from 3:00 p.m. to 4:00 p.m. local time is consistent across all summer seasons.

Generation–Solar Availability

The following table represents expected solar availability by hour for the summer peak demand day. Availability of solar resources is **74%** for **3:00 p.m.** local time, which is unchanged from last year's LTRA. However, with the peak demand hour shifting to **4:00 p.m.** local time, only **56%** of the solar capacity is expected to show a significant drop from last year's LTRA.

Expected Output of Solar Resources by Hour in CA/MX Area			
Hour Beginning	**Solar Availability**	**Hour Beginning**	**Solar Availability**
12:00–5:00 a.m.	0%	1:00 p.m.	85%
6:00 a.m.	1%	2:00 p.m.	81%
7:00 a.m.	18%	**3:00 p.m.**	**74%**
8:00 a.m.	47%	**4:00 p.m.**	**56%**
9:00 a.m.	68%	5:00 p.m.	29%
10:00 a.m.	77%	6:00 p.m.	7%
11:00 a.m.	85%	7:00–11:00 p.m.	0%
12:00 p.m.	86%		

Note, it is not that the portfolio has significantly changed from one LTRA to the next, but rather the hour for peak demand that is being shown in the LTRA has shifted; this puts the LTRA closer to the hours of risk that have been highlighted in the ProbA assessments. The ProbA assessment considers all hours of each year. The shift from one hour to the next was already reflected in the ProbA assessment results. This also begins to reconcile where the LTRA shows healthy CA/MX margins, but the ProbA assessment shows high levels of load-loss risk and expected unserved energy potential. As the peak demand hour continues to shift toward later in the evening, the LTRA results will continue to highlight more of the risk the ProbA assessment has shown.

WECC-NWPP & RMRG

The NWPP & RMRG assessment area has experienced a change in the hour of peak demand, just as has occurred in the CA/MX assessment area. However, in the case of NWPP & RMRG, the peak demand hour has shifted back to 3:00 p.m. from 4:00 p.m. The change in demand hour has the opposite impact on the solar output compared to the CA/MX assessment area: solar availability in NWPP & RMRG has increased compared to last year's LTRA, while at the same time, hydro resources have decreased slightly due to the time shift. With only existing resources, this area is expected to be short of the Reference Margin Level calculated to meet a 1-day-in-10-year level of reliability beginning in the summer of 2026. However, with Tier 1 and 2 resources, this shortfall is delayed until the summer of 2031, the last season of this assessment. With prospective resources, NWPP & RMRG meets its Reference Margin Level in all years of the assessment.

WECC-SRSG

The SRSG assessment area has seen little change from last year's LTRA. Demand is slightly decreased while resources have slightly increased leading to better reserve margins compared to the calculated Reference Margin Level needed to maintain a 1-day-in-10-year level of reliability. With existing resources, this area falls below the Reference Margin Level beginning the summer of 2030; however, with Tier 1 and 2 resources expected to be in-service by this period, this shortfall is mitigated. Although SRSG is highly reliant on baseload resources, in particular natural gas resources, the level of solar penetration is beginning to become a significant portion of the portfolio. Given the variability of solar resources and the volatility from one hour to the next (especially in the evening as the sun sets), WECC will continue to monitor this area to proactively mitigate any resource adequacy risk.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[63] for the summer and winter of each year.[64] Projected total internal demand is based on normal weather (50/50 distribution)[65] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area

Assessment Area	Peak Season	Coincident / Noncoincident[66]	Load Forecasting Entity
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
NPCC-Maritimes	Winter	Noncoincident	Maritimes Subareas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
SPP	Summer	Noncoincident	SPP LSEs
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AB	Winter	Noncoincident	WECC BAs, aggregated by WECC

[63] Glossary of Terms Used in NERC Reliability Standards.
[64] The summer season represents June–September and the winter season represents December–February.
[65] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.
[66] 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.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident**[66]	**Load Forecasting Entity**
WECC-NWPP-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-NWPP-US	Summer	Noncoincident	
WECC-NWPP-RMRG	Summer	Noncoincident	
WECC-SRSG	Summer	Noncoincident	

Resource Categories
NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. 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 generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct. • Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements • Firm capacity transfers (Imports minus Exports): transfers with firm contracts • Less confirmed retirements[67]
Prospective Resources: Includes all "anticipated resources" plus the following: • Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons. • Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements • Expected (nonfirm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation. • Less unconfirmed retirements.[68]

[67] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.
[68] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories
Generating Unit Status: Status at time of reporting: • **Existing:** It is in commercial operation. • **Retired:** It is permanently removed from commercial operation. • **Mothballed**: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain." • **Cancelled**: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue. • **Tier 1**: A unit that meets <u>at least one</u> of the following guidelines (with consideration for an area's planning processes):[69] ▪ Construction complete (not in commercial operation) ▪ Under construction ▪ Signed/approved Interconnection Service Agreement (ISA) ▪ Signed/approved Power Purchase Agreement (PPA) has been approved ▪ Signed/approved Interconnection Construction Service Agreement (CSA) ▪ Signed/approved Wholesale Market Participant Agreement (WMPA) ▪ Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities) • **Tier 2**: A unit that meets <u>at least one</u> of the following guidelines (with consideration for an area's planning processes):[70] ▪ Signed/approved Completion of a feasibility study ▪ Signed/approved Completion of a system impact study ▪ Signed/approved Completion of a facilities study ▪ Requested Interconnection Service Agreement ▪ Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs) • **Tier 3**: A units in an interconnection queue that do not meet the Tier 2 requirement.

[69] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[70] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin: The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin: The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
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 increased 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/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of the assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2022 Summer Reliability Assessment

May 2022

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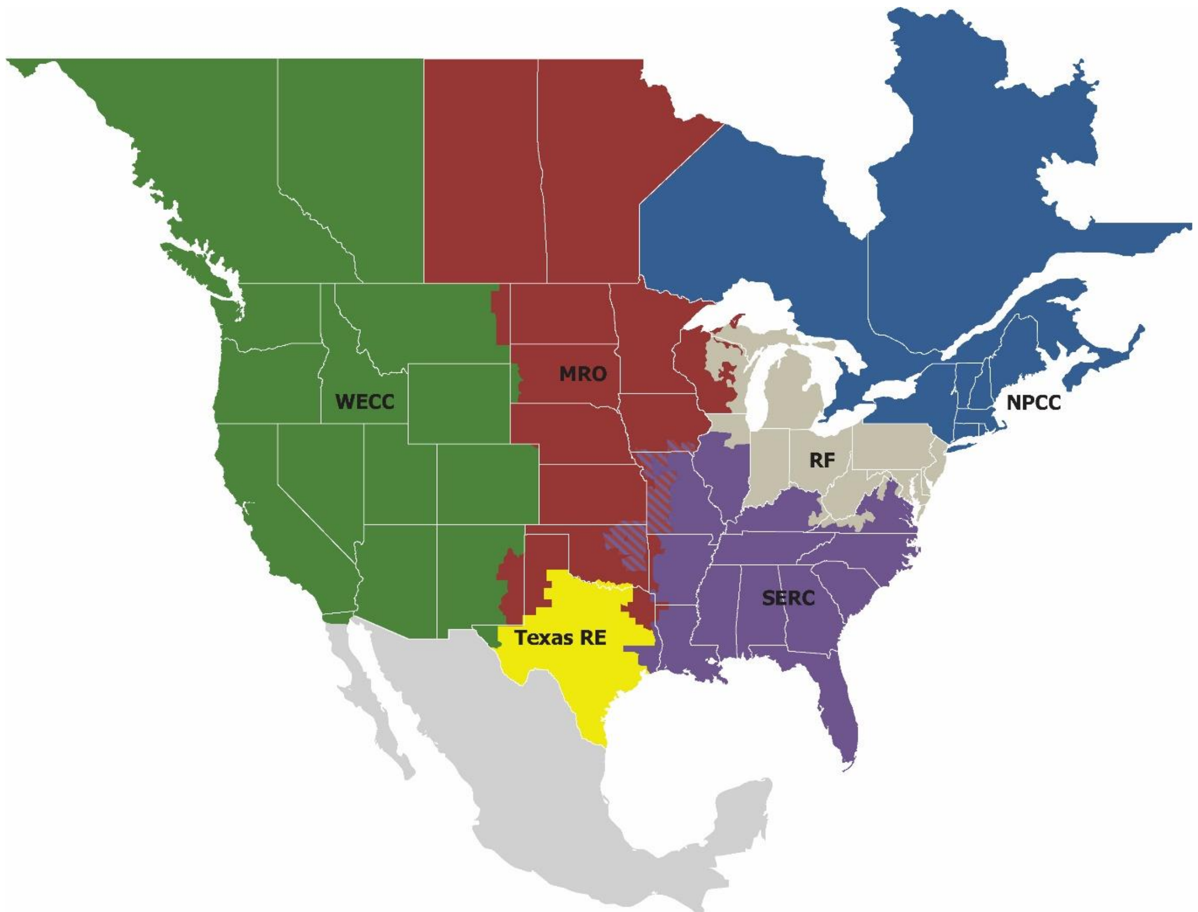
Preface

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

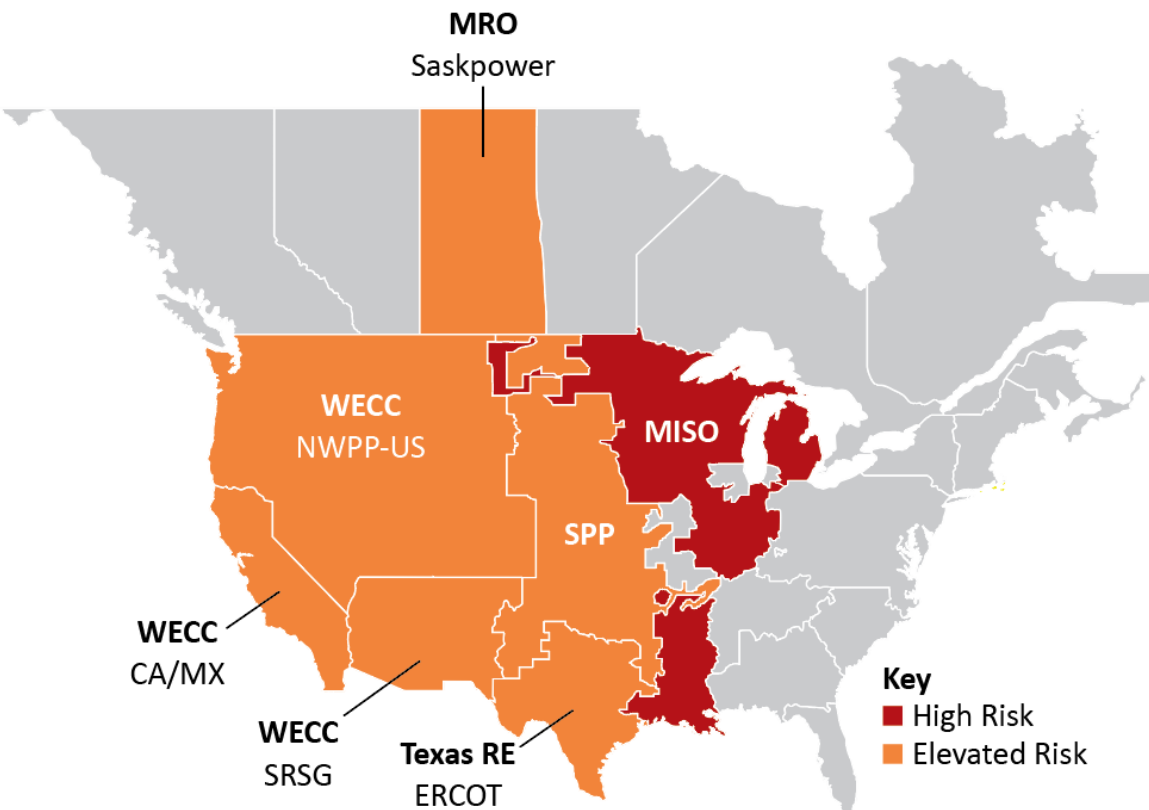


Figure 1: Summer Reliability Risk Area Summary

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.

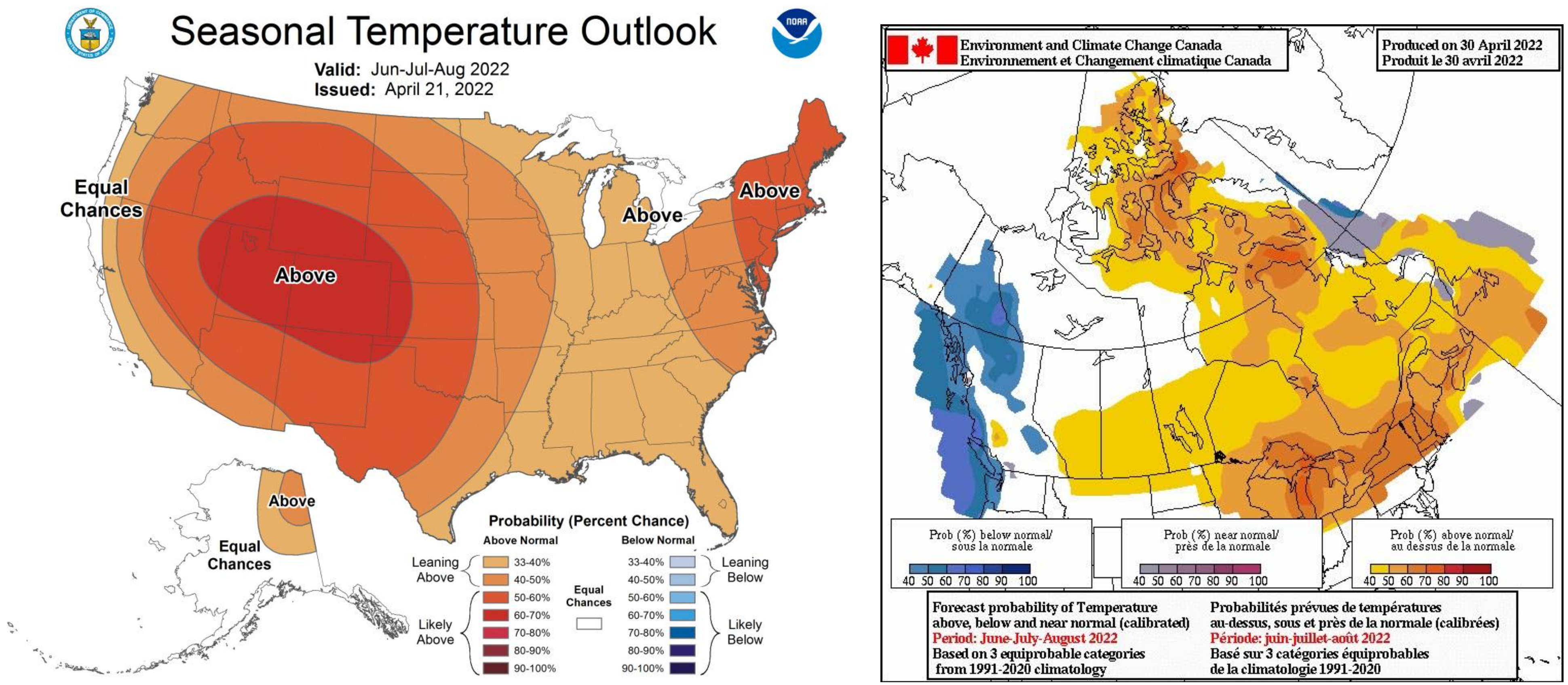


Figure 2: United States and Canada Summer Temperature Outlook[2]

[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.

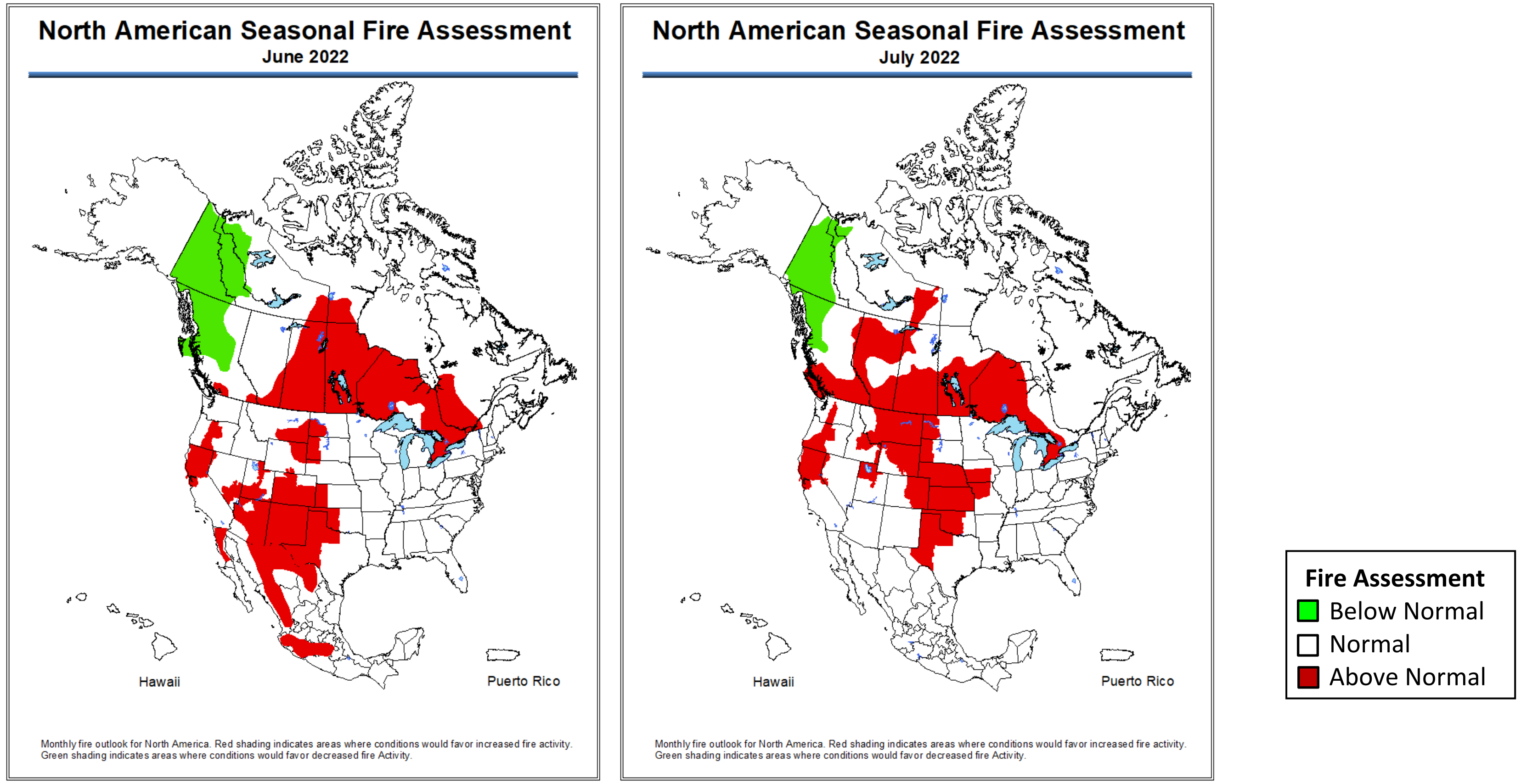


Figure 3: North American Seasonal Fire Assessment for June and July 2022[3]

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.

[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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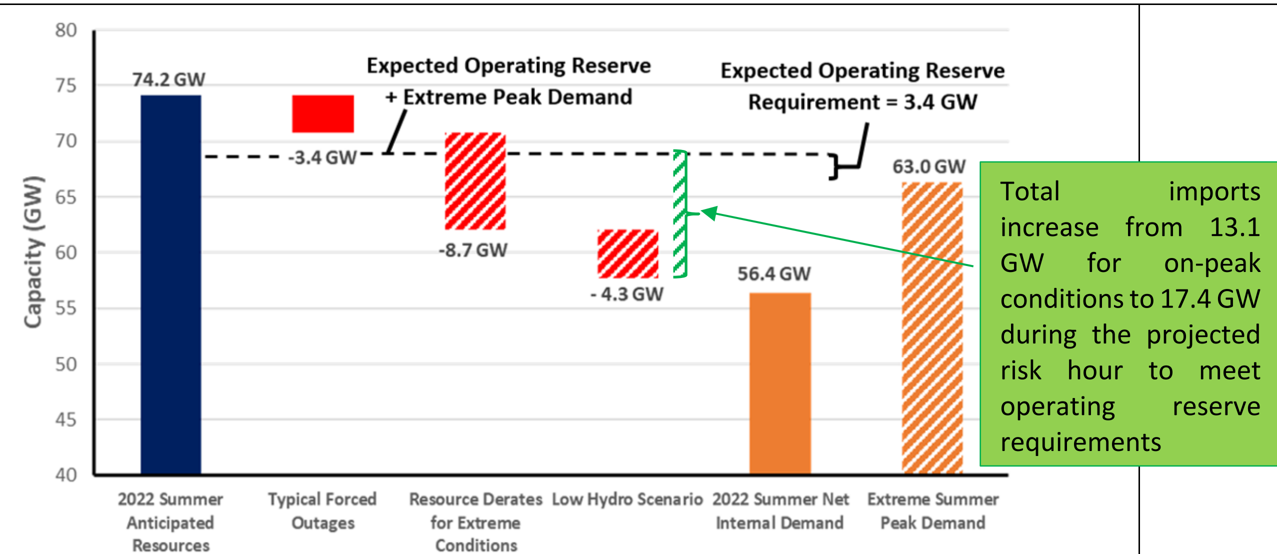
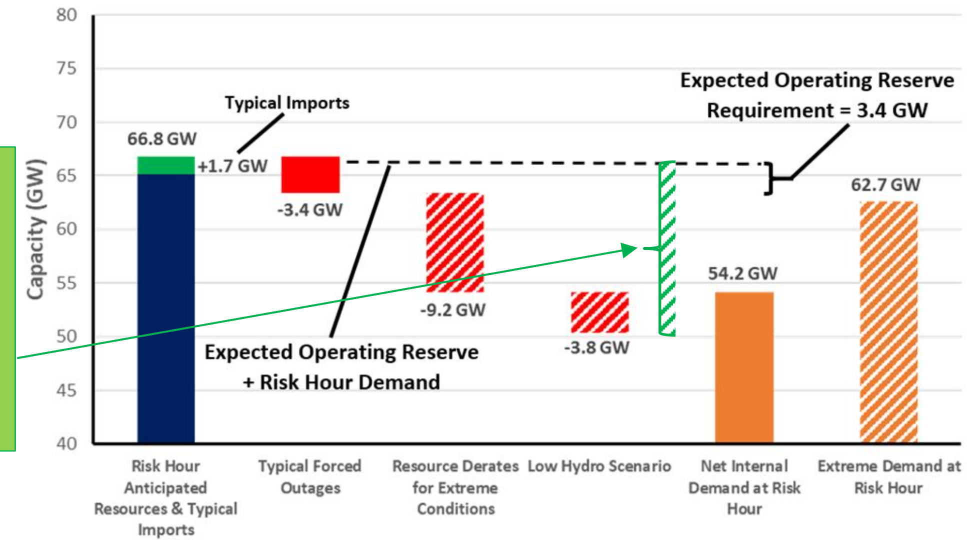
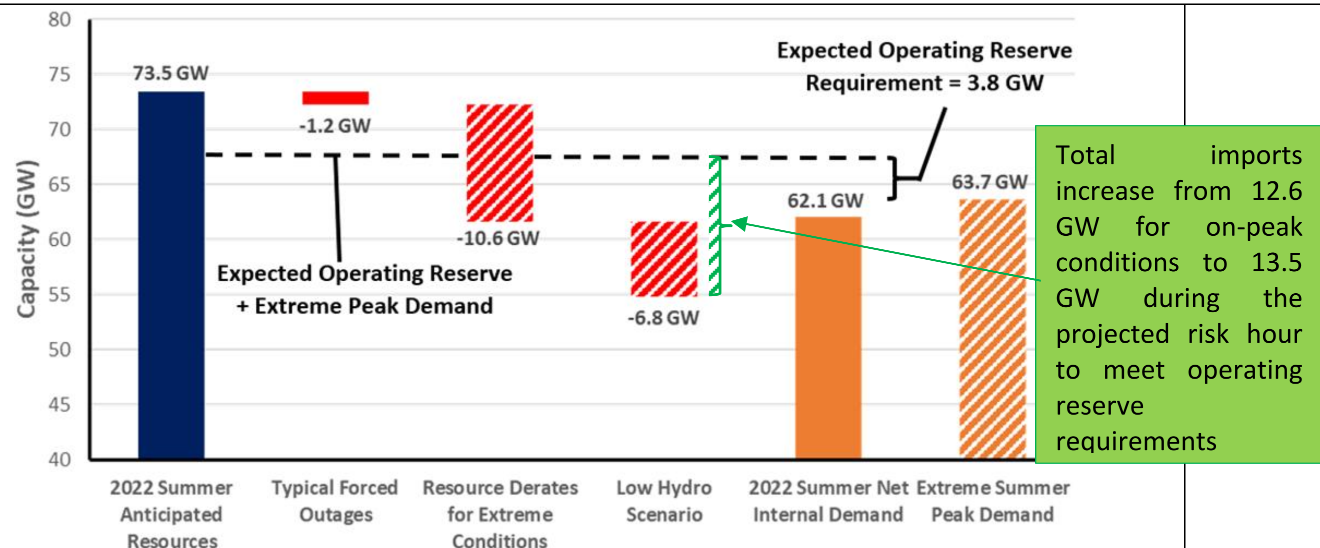
[5] WECC August Heat Wave Event information: WECC's *August Heat Wave Analysis* Presentation



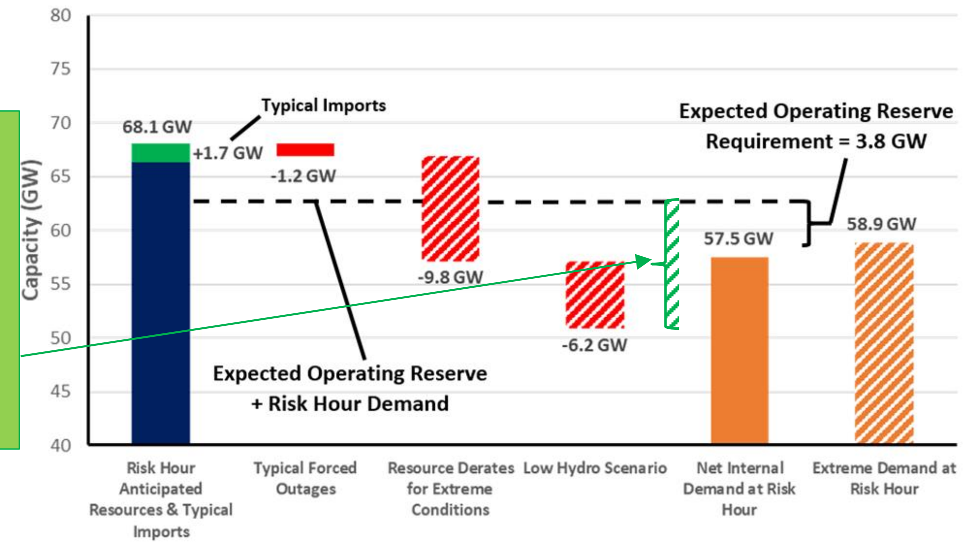
WECC-CA/MX On-Peak



WECC-CA/MX Risk Hour (8:00 p.m. local)

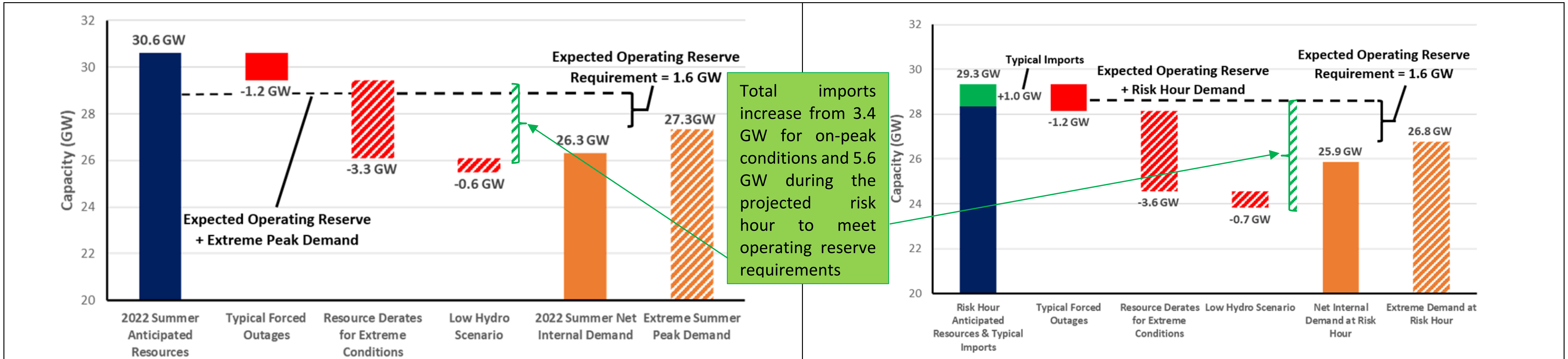


WECC-NWPP-US On-Peak



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

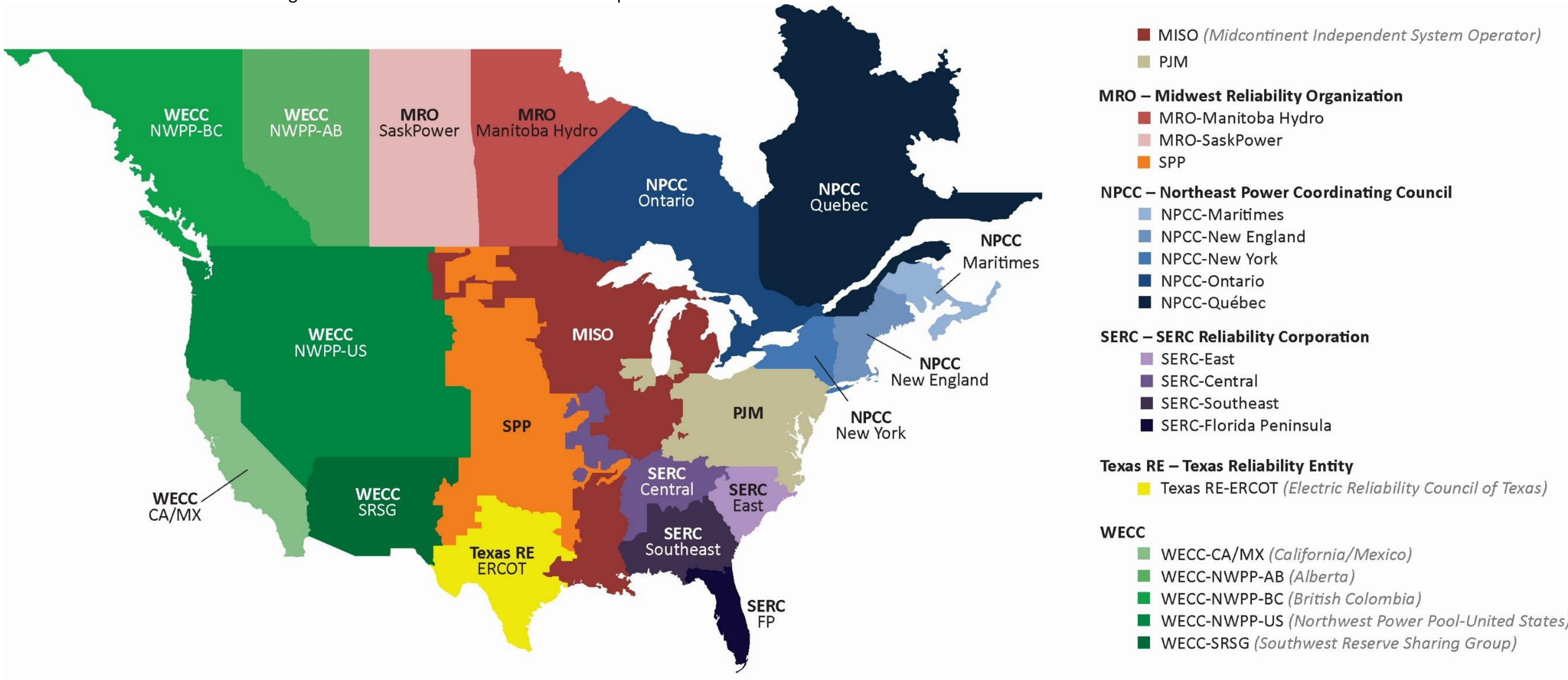
When above-normal temperatures extend over a wide area, resources can be strained in multiple assessment areas simultaneously, increasing the risk of shortfalls. Some assessment areas expect imports from other areas to be available to meet periods of peak demand and have contracted for firm transfer 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.

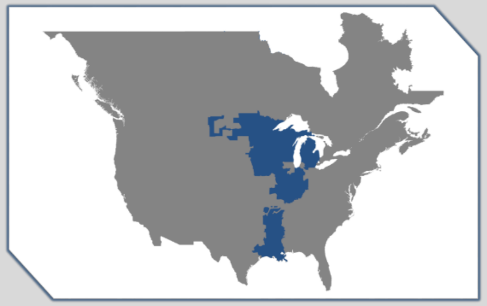
Table 3: 2021 and 2022 On-Peak Net Firm Transfers

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.

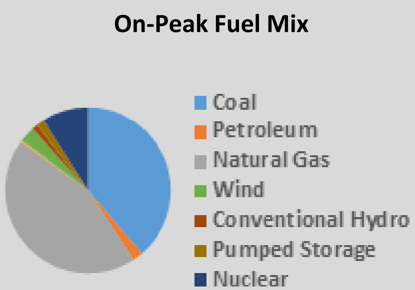




MISO

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.

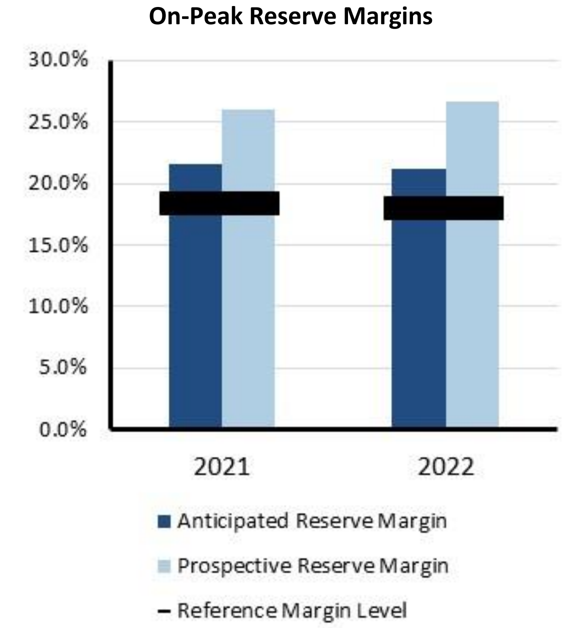


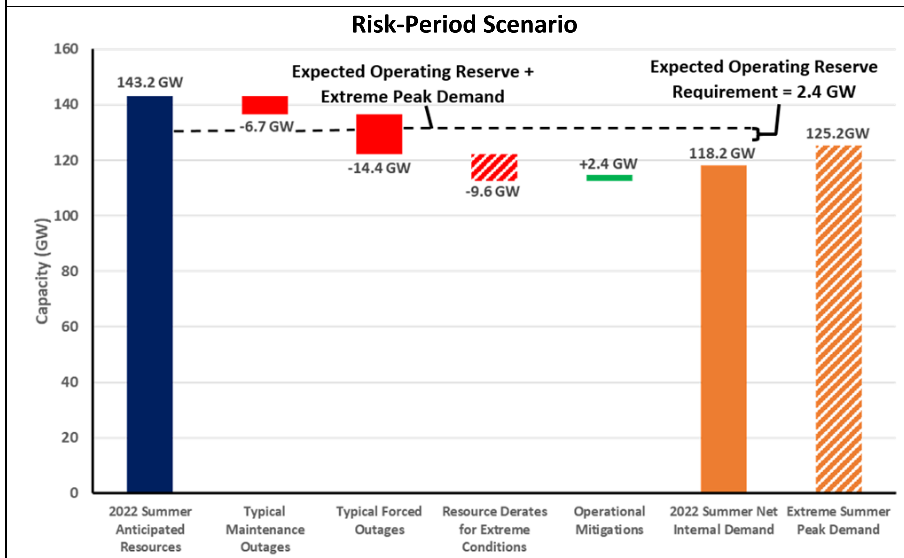
Highlights

- 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.





Scenario Description (See Data Concepts and Assumptions)

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

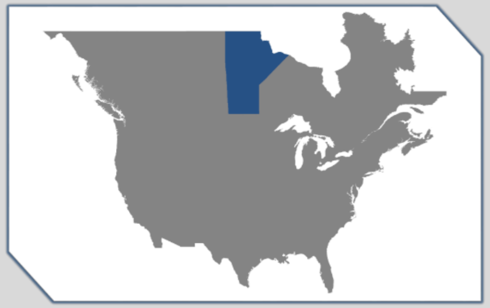
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

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

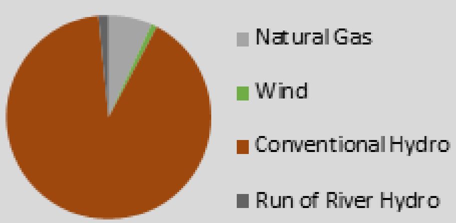


MRO-Manitoba Hydro

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

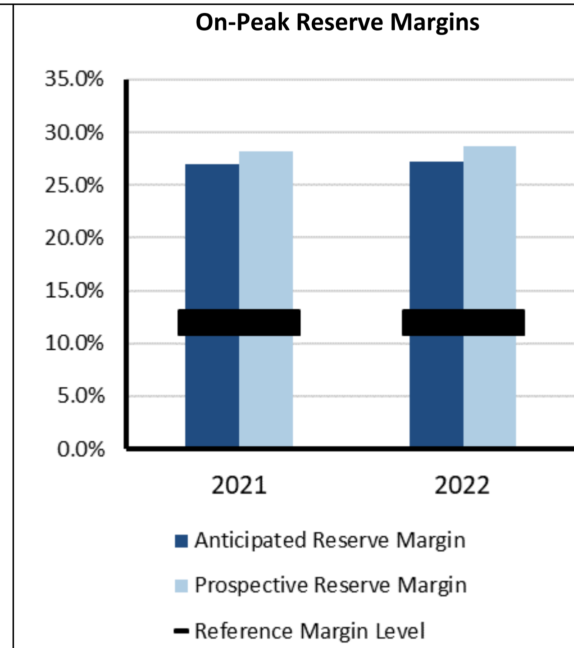


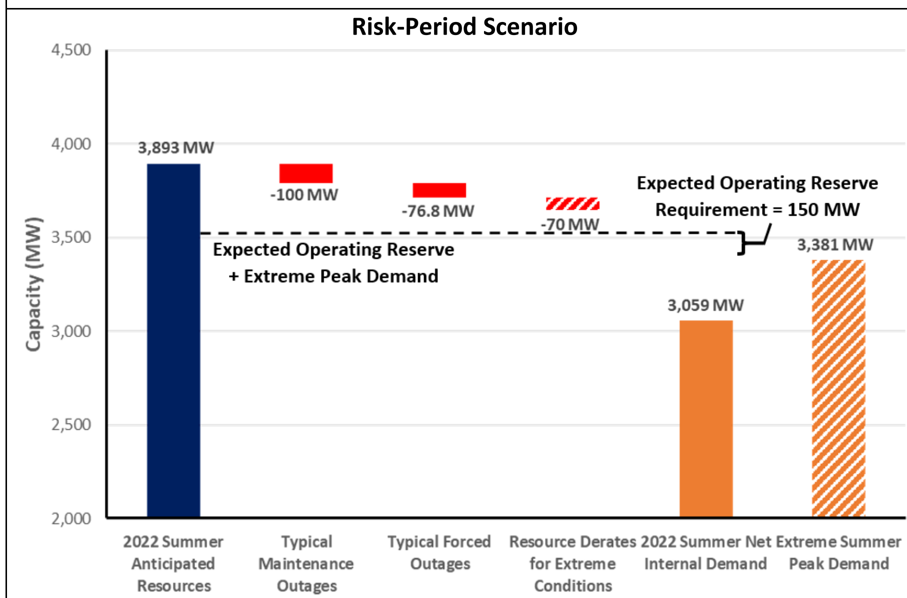
Highlights

- 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.





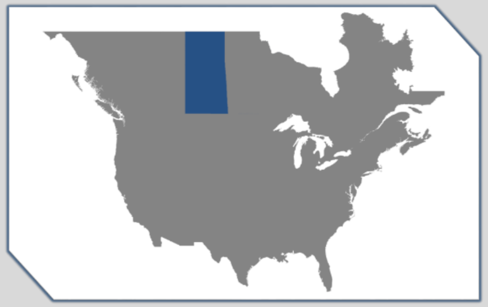
Scenario Description (See [Data Concepts and Assumptions](#))

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



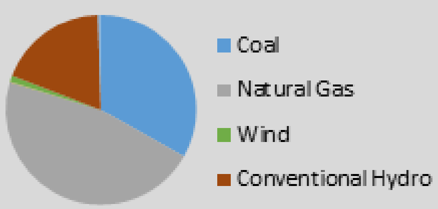
MRO-SaskPower

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



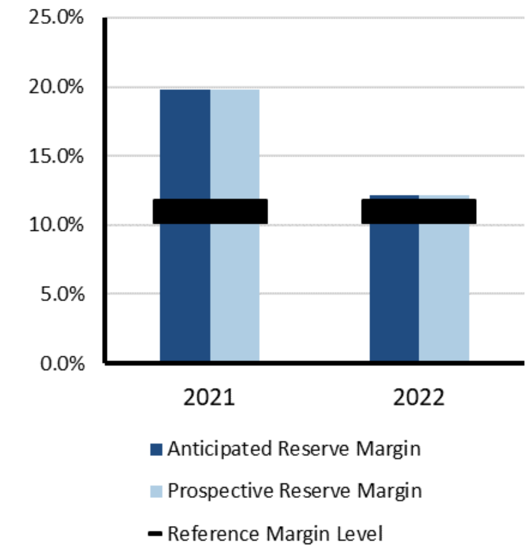
Highlights

- 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.

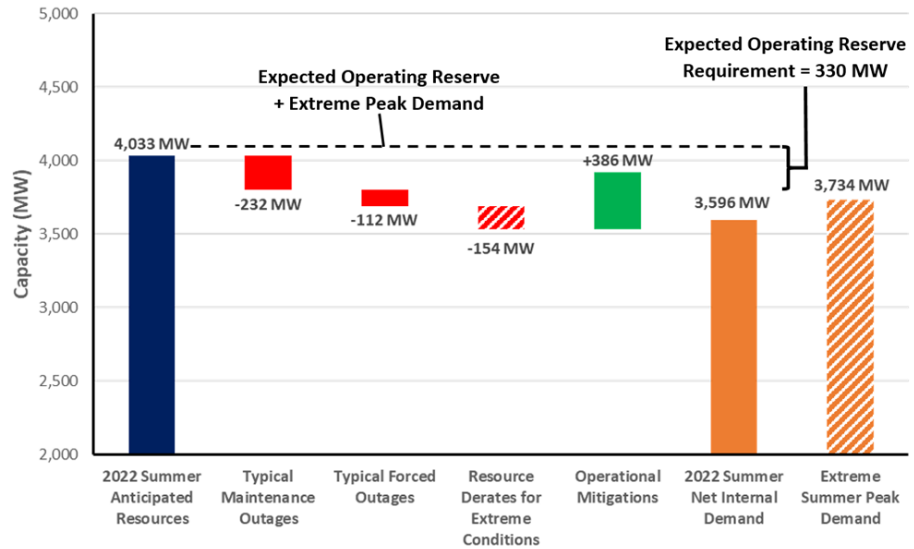
Risk Scenario Summary

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

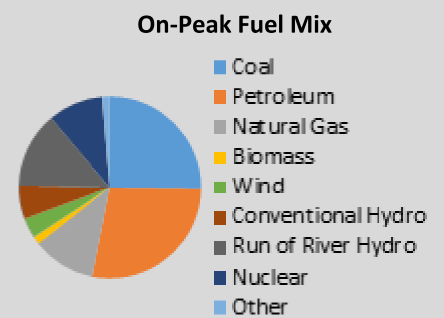
Maintenance Outages: Average of planned maintenance outages for the summer months of June–September 2021

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

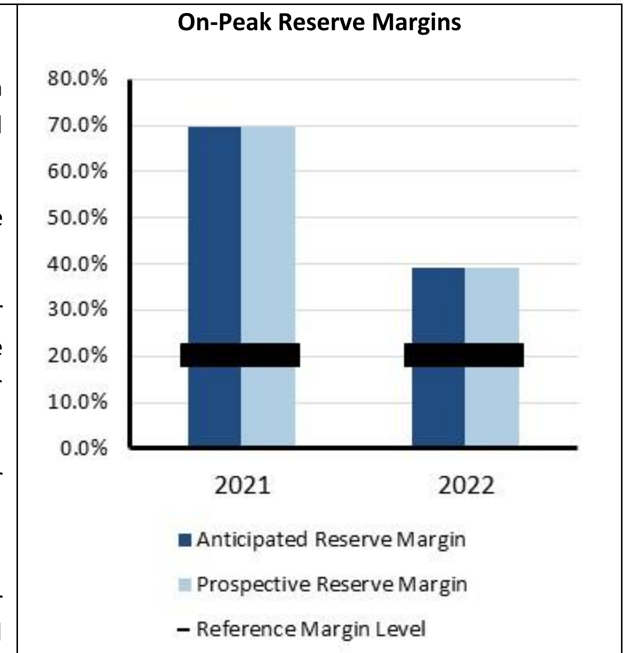
NPCC-Maritimes

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.



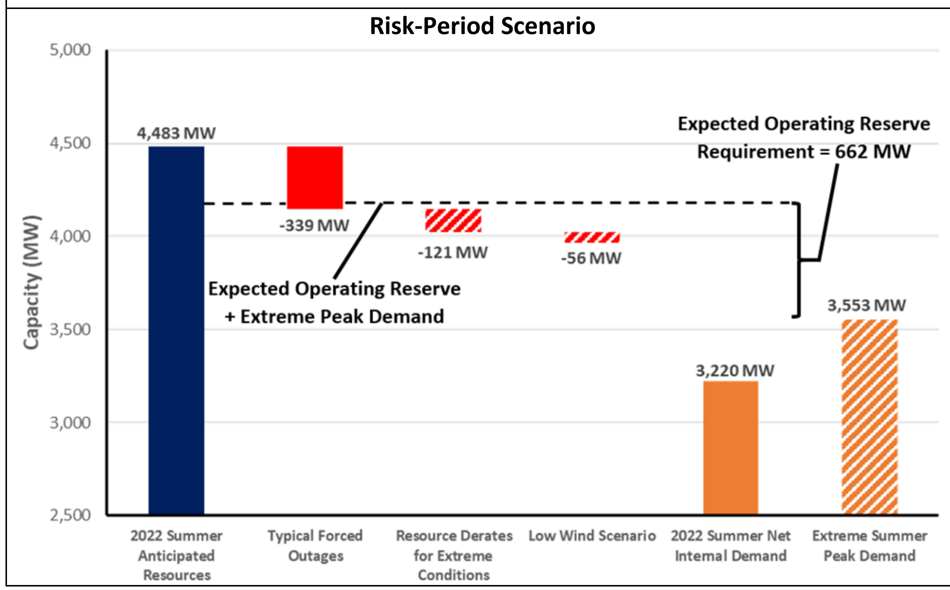
Highlights

- 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.



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

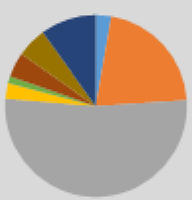
Low Wind Scenario: A low-likelihood scenario resulting in no wind resources

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

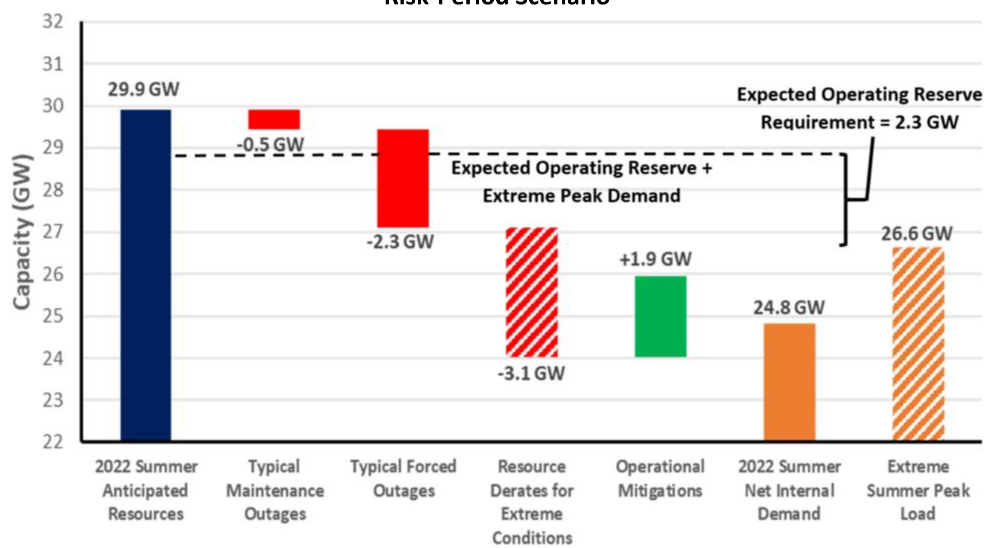
- The New England area expects to have sufficient capacity to meet the 2022 summer peak demand forecast. As of April 5, 2022, the peak summer (net internal) demand is forecast to be 24,817 MW for the week of July 24, 2022, with a projected net margin of 1,705 MW (6.9%). The 2022 summer (net internal) 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.

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.

On-Peak Reserve Margins

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

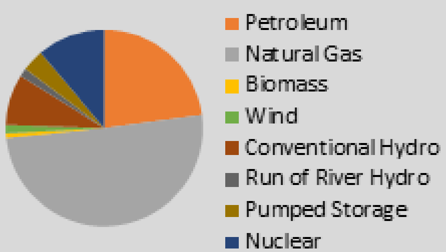
Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

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



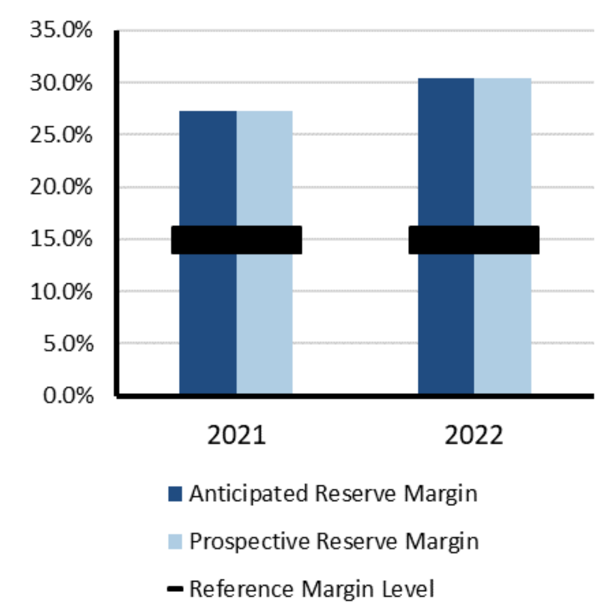
Highlights

- 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.

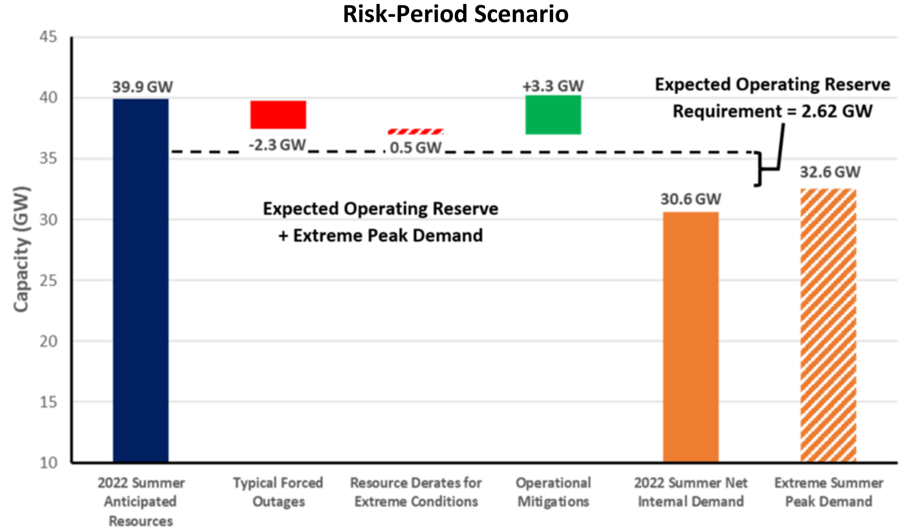
Risk Scenario Summary

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

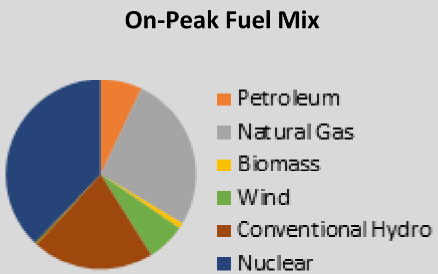
Forced Outages: Based on historical 5-year averages

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

NPCC-Ontario

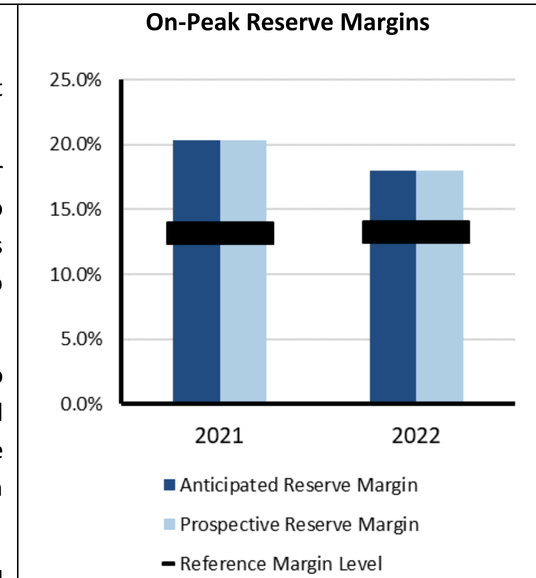
The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million.

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



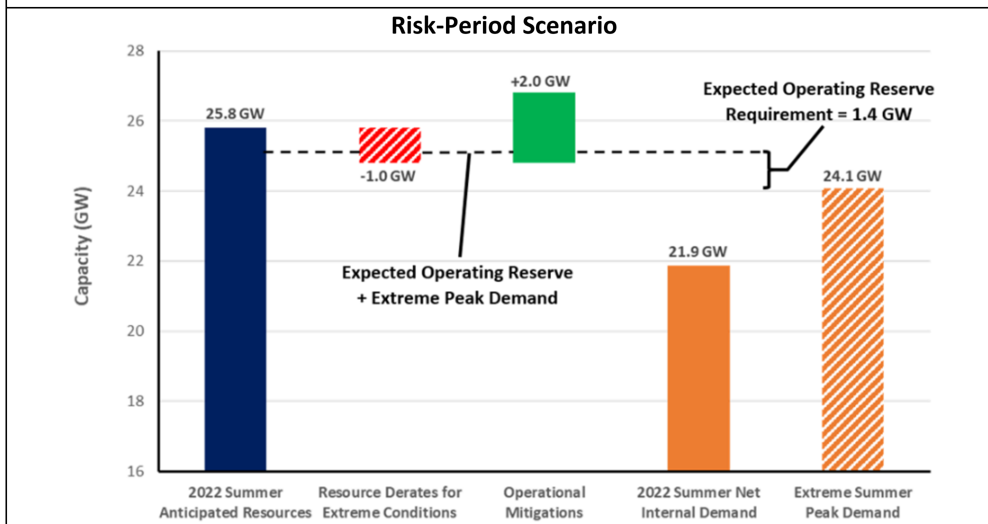
Highlights

- 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.



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

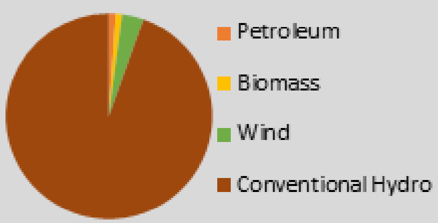
Operational Mitigations: Imports anticipated from neighbors during emergencies

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



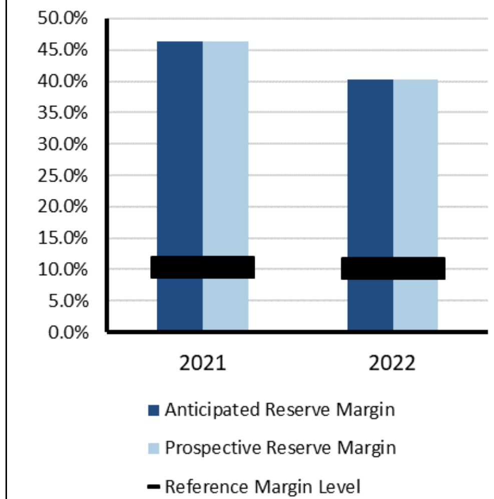
Highlights

- 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.

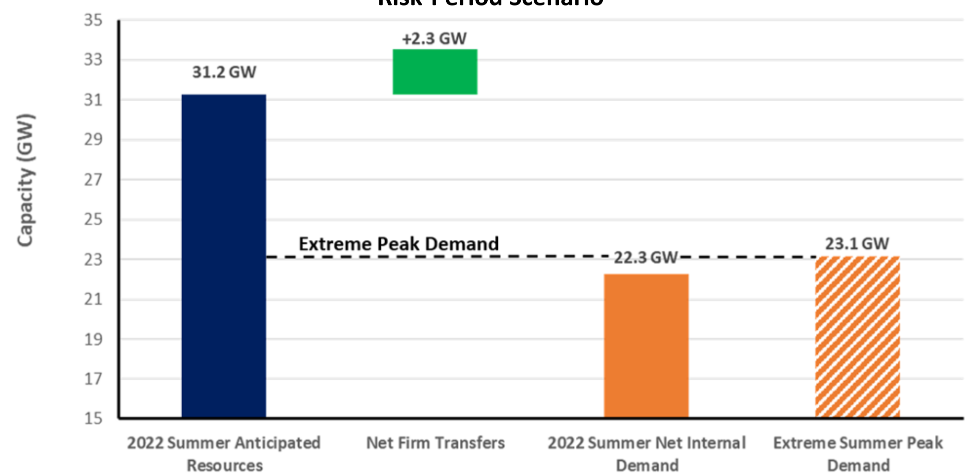
Risk Scenario Summary

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

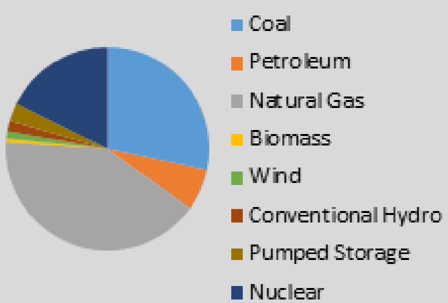
Net Firm Transfers: Imports anticipated from neighbors during emergencies

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

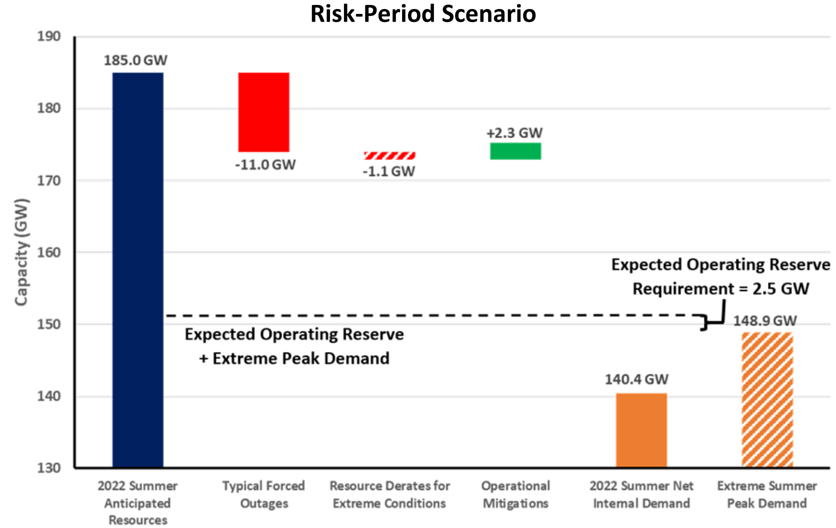
- PJM expects no resource problems over the entire 2022 summer peak season because installed capacity is over two times the reserve requirement.
- PJM continues to request fuel inventory and supply data of coal and oil resources (including dual-fuel units). This data request, sent every two weeks, started 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.

On-Peak Reserve Margins

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

Risk-Period Scenario



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

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

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

Forced Outages: 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

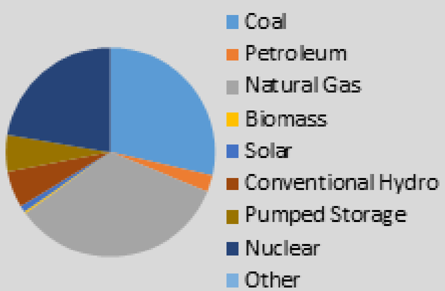
SERC-East

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



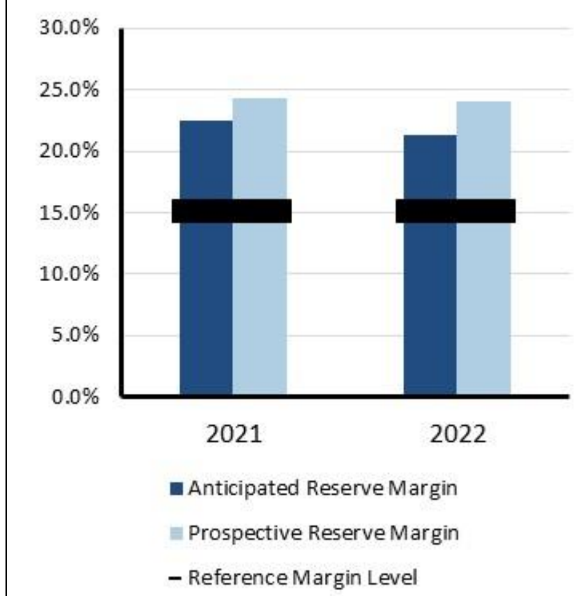
Highlights

- 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).

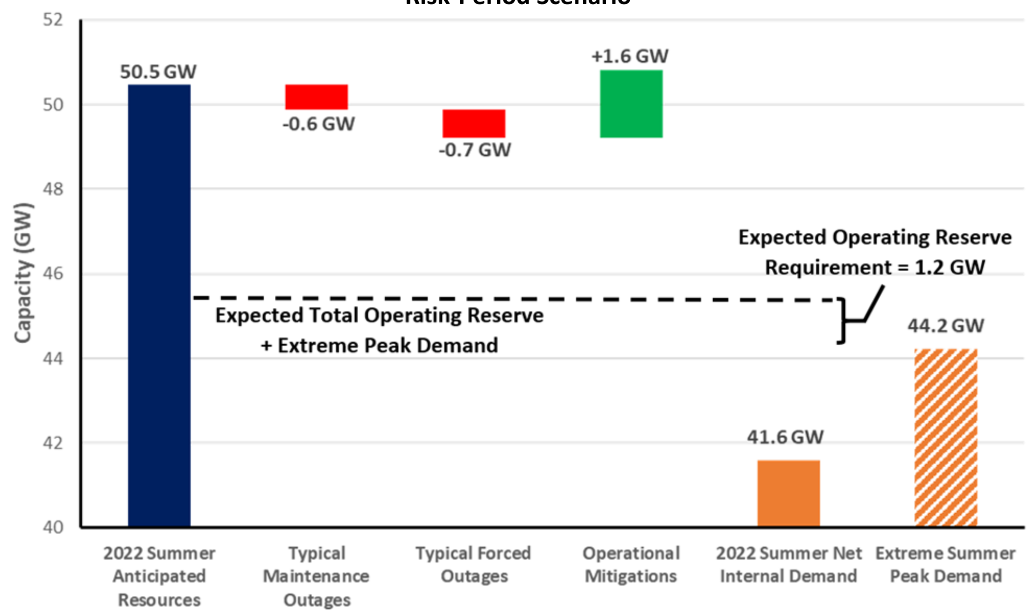
Risk Scenario Summary

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

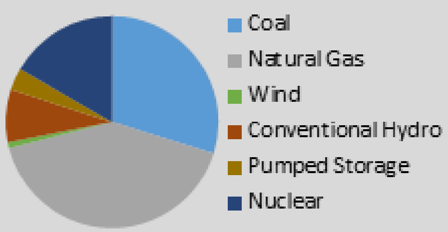
SERC-Central

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



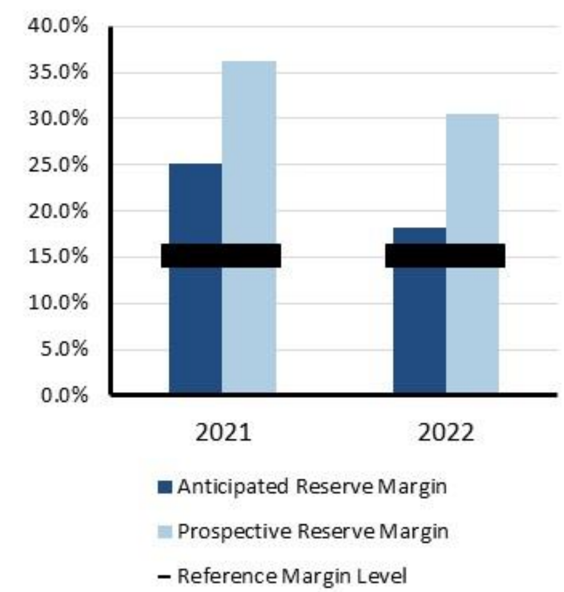
Highlights

- 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.

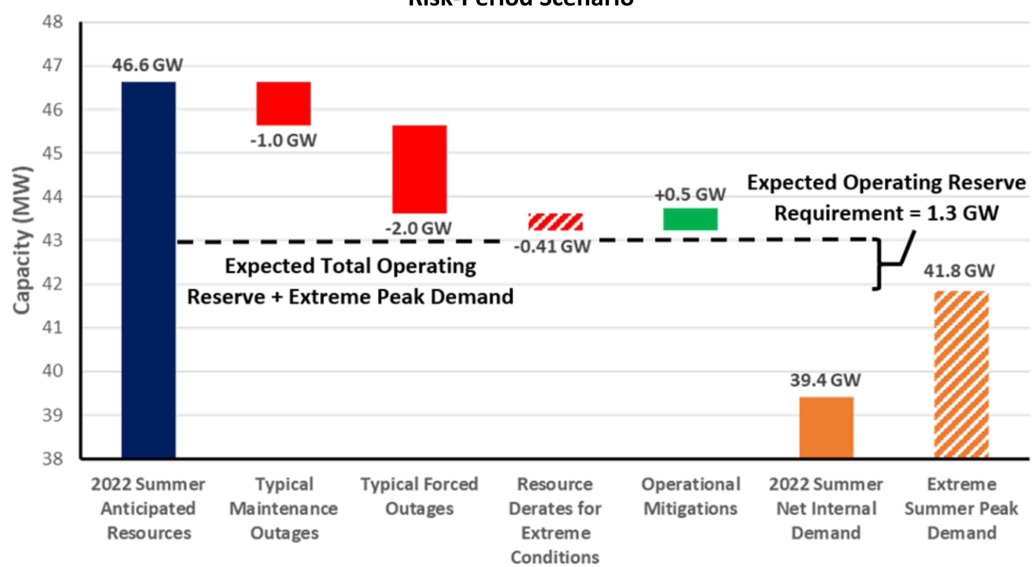
Risk Scenario Summary

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

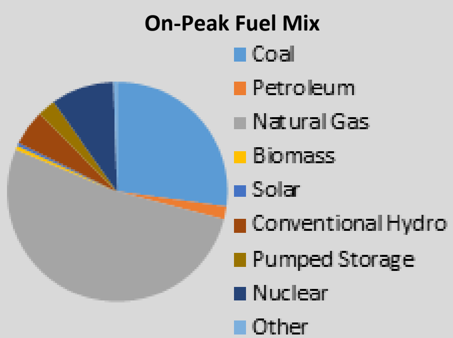
Operational Mitigations: A total of 0.5 GW based on operational/emergency procedures

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.

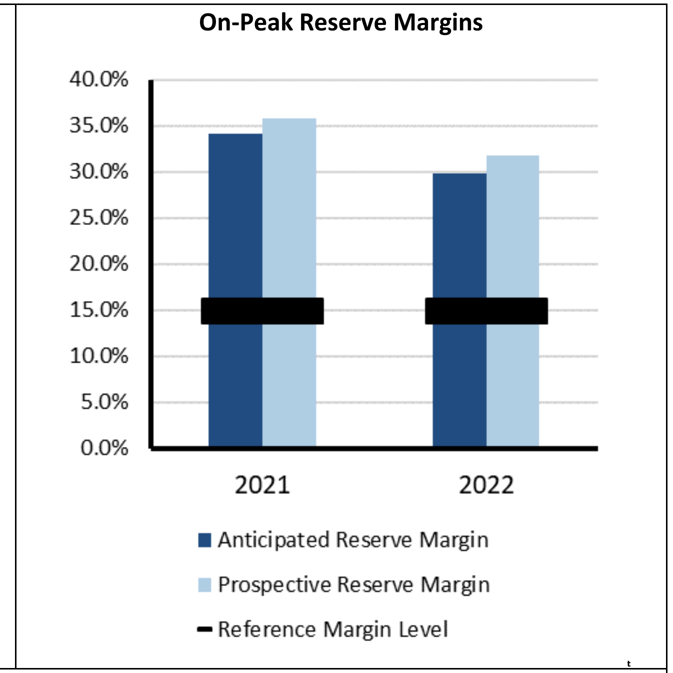


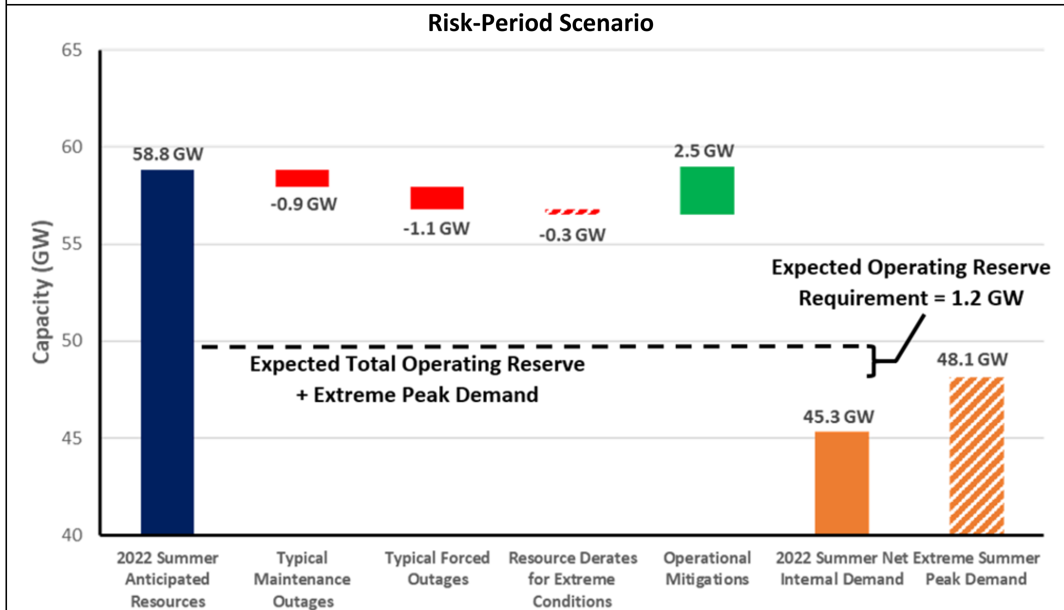
Highlights

- 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.





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

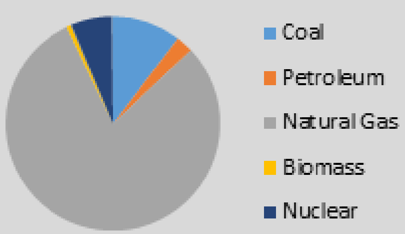
SERC-Florida Peninsula

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



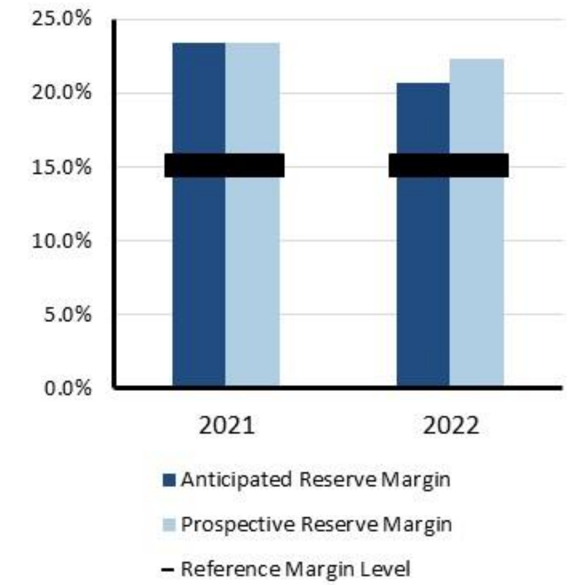
Highlights

- 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).

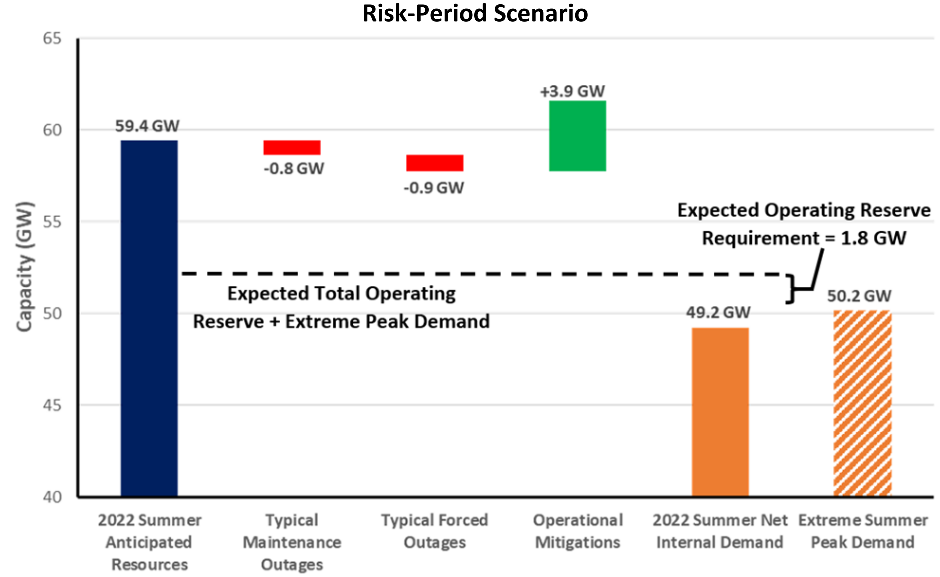
Risk Scenario Summary

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

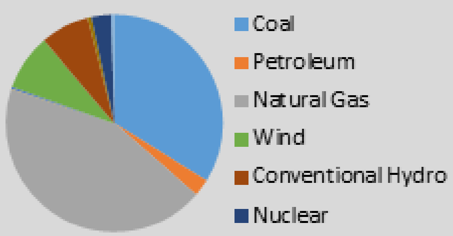
Operational Mitigations: A total of 3.9 GW based on operational/ emergency procedures

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



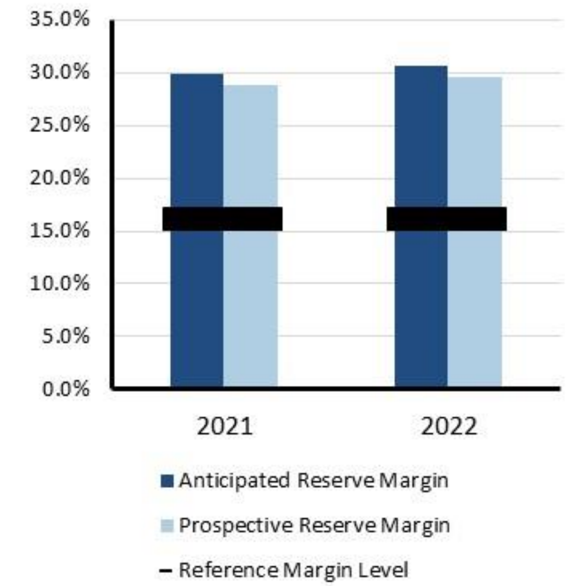
Highlights

- 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.

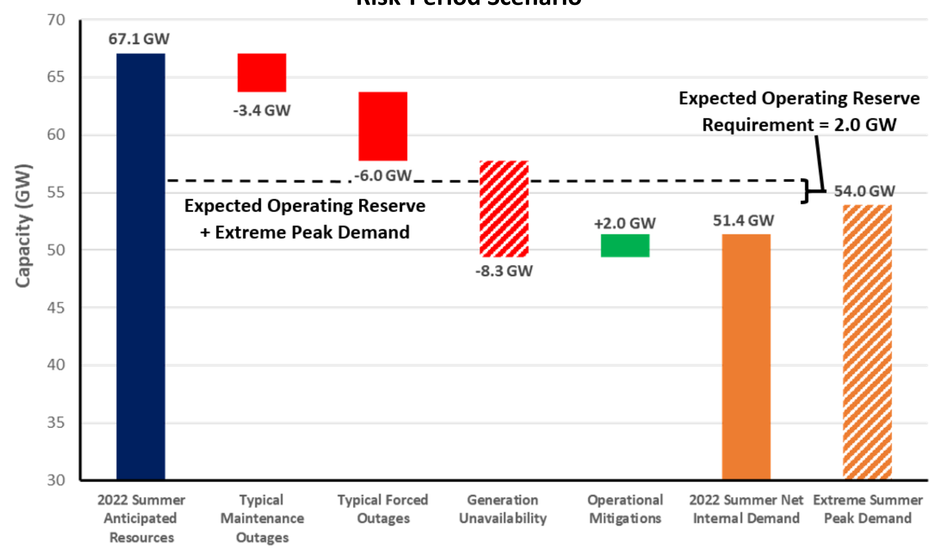
Scenario Summary

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

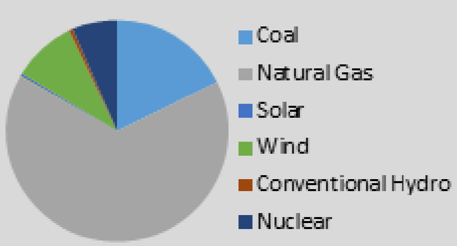
Generation Unavailability: Risk from higher outages to protect against 99.5th percentile of historical coincident generation

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



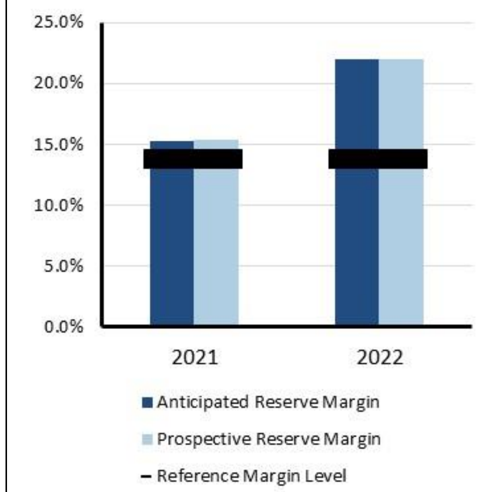
Highlights

- 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%.

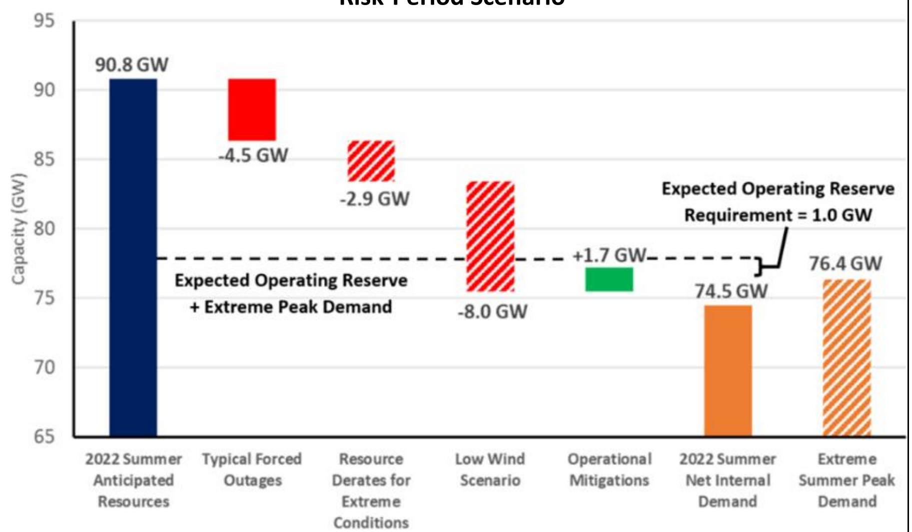
Risk Scenario Summary

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)

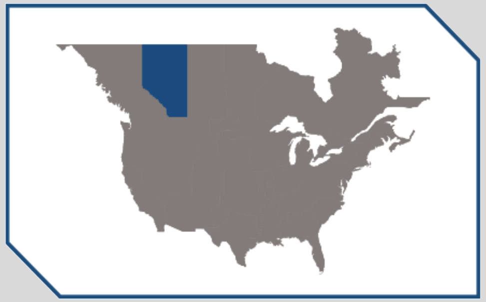
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand represents 90th 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 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

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.

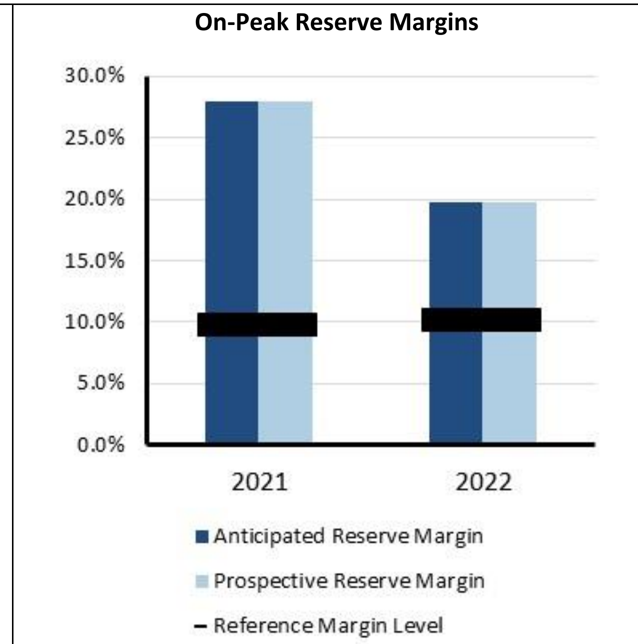
Highlights

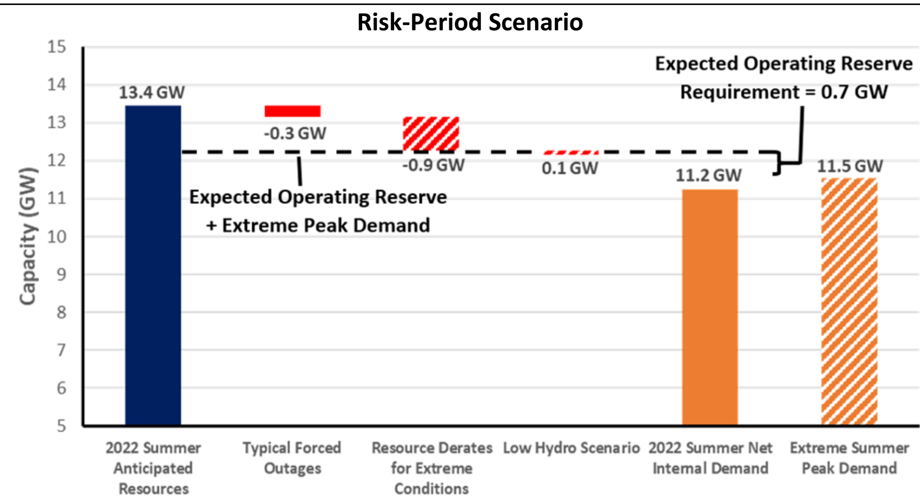
- There are potential natural gas supply-side tightening concerns.
- Reserve margins are tighter but still expected to be adequate.
- Based on a WECC probabilistic assessment, the WECC-NWPP-AB assessment area had negligible LOLH and EUE.

  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)

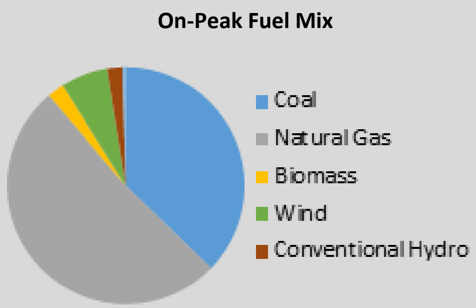
Risk Period: Highest risk for unserved energy at peak demand hour

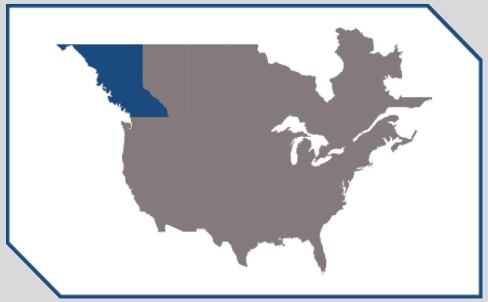
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions





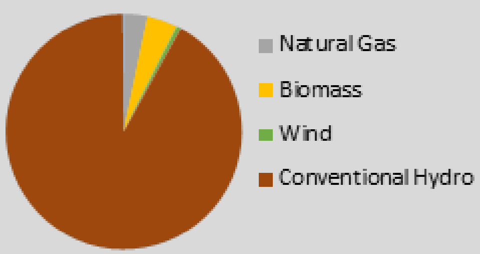
WECC-NWPP-BC

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



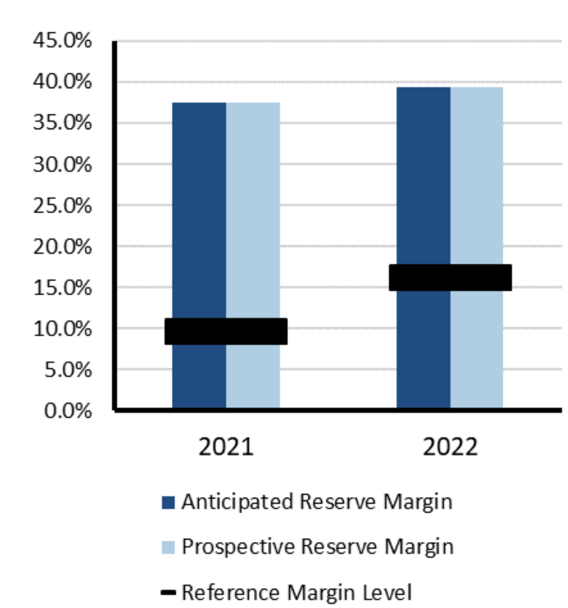
Highlights

- 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.

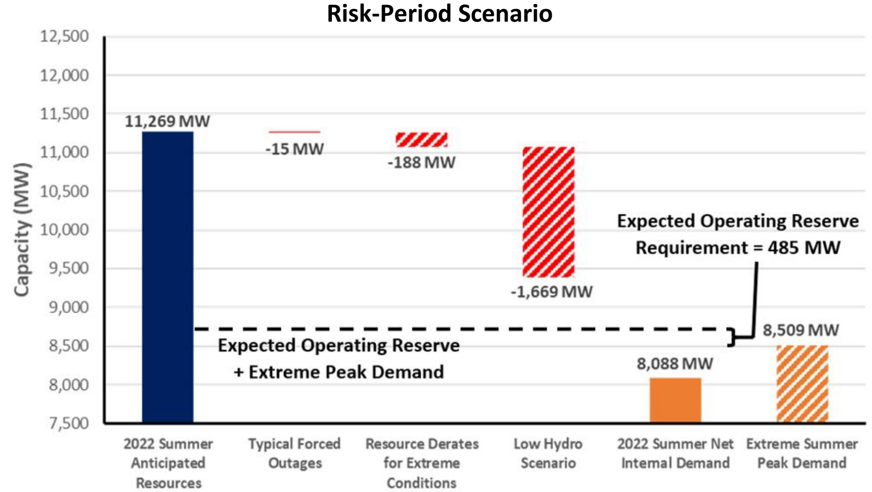
Risk Scenario Summary

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

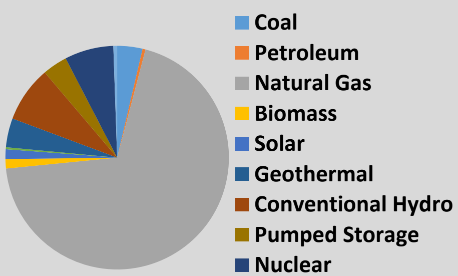
WECC-CA/MX

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



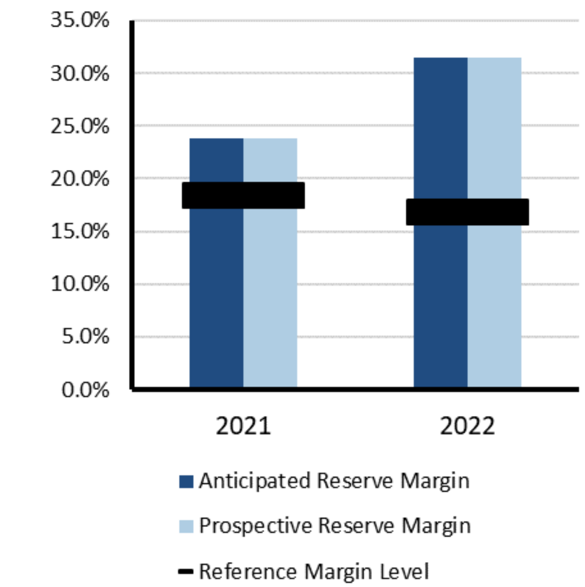
Highlights

- 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.

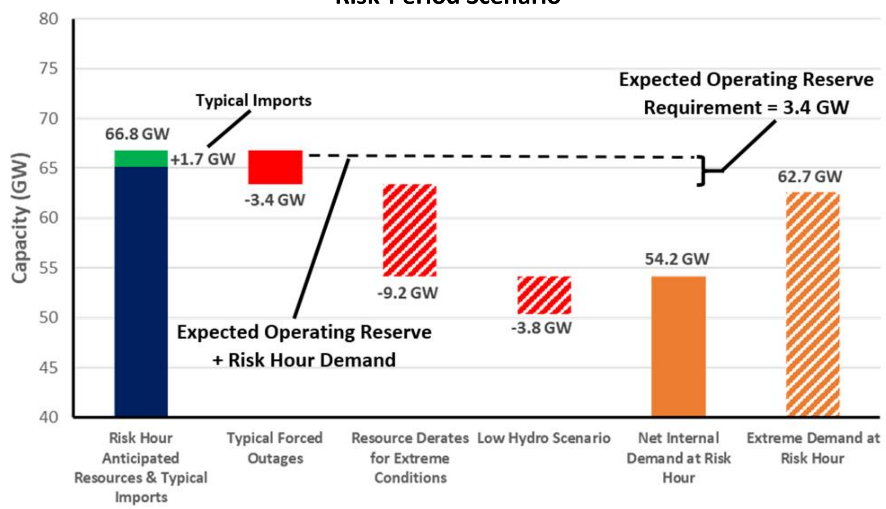
Risk Scenario Summary

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 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

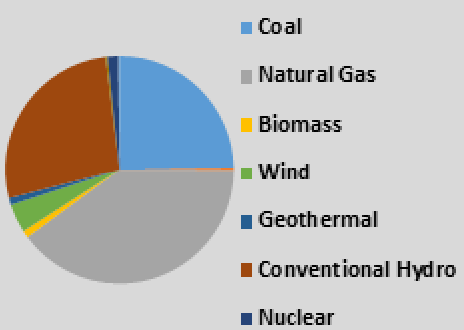
WECC-NWPP-US

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



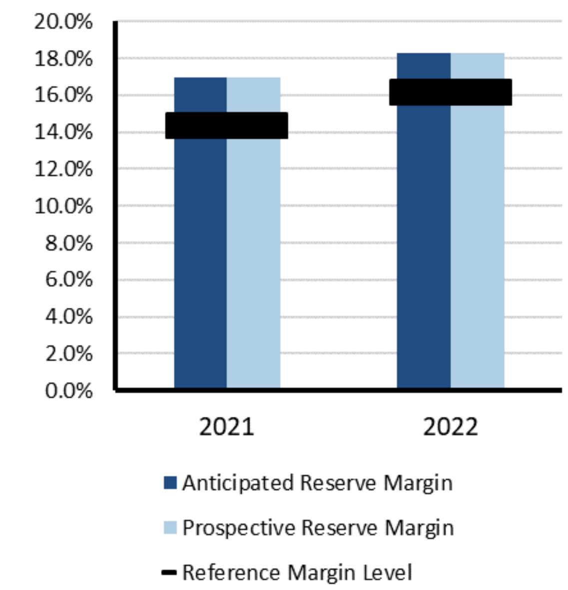
Highlights

- 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.

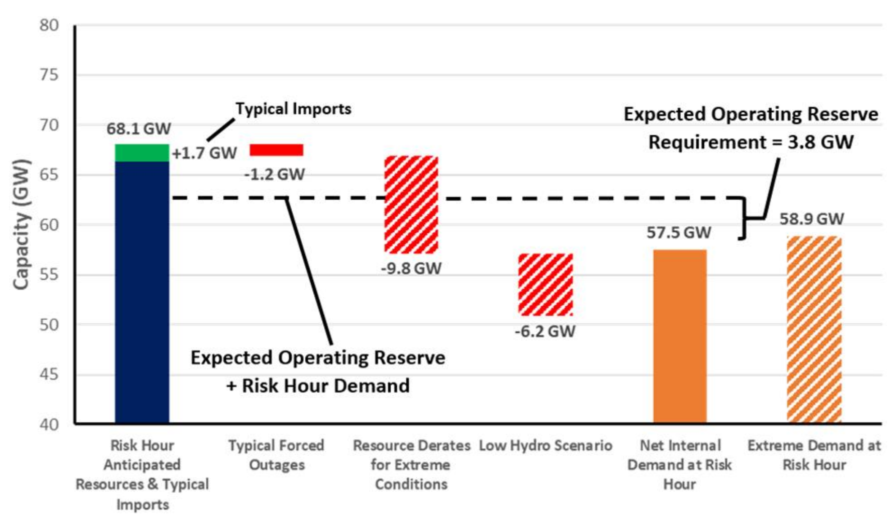
Risk Scenario Summary

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)

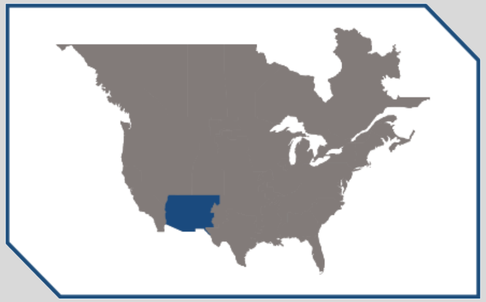
Risk Period: Highest risk for unserved energy at 7:00 p.m. local time as solar PV output is diminished and demand remains high

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



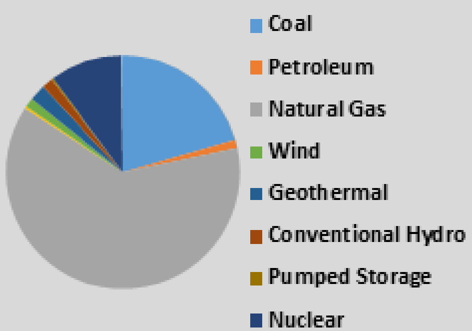
WECC-SRSG

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.

On-Peak Fuel Mix



Highlights

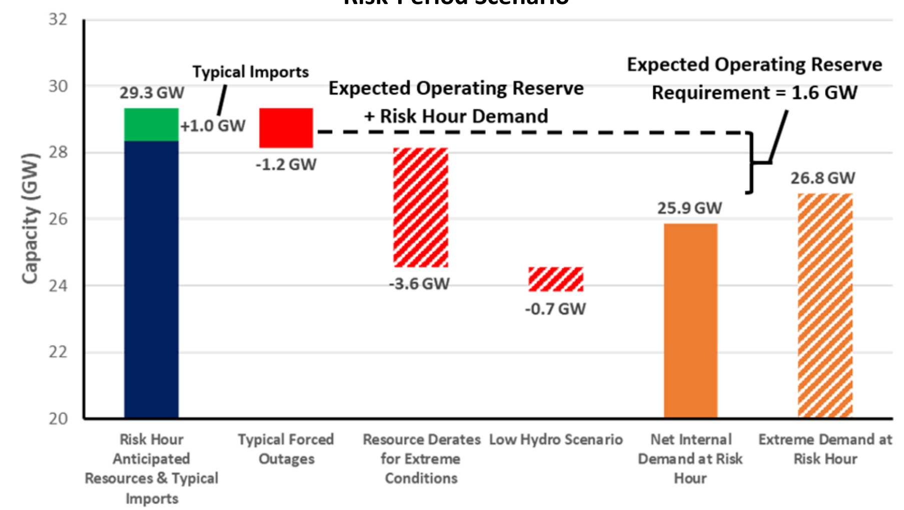
- Drought and supply chain issues are the main reliability concerns. Many solar developers are indicating to utilities that they will not be able to meet expected commission dates under executed and approved power purchase agreements, including at least 120 MW of PV planned for the 2022 summer.
- Reserve 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.

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

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**.

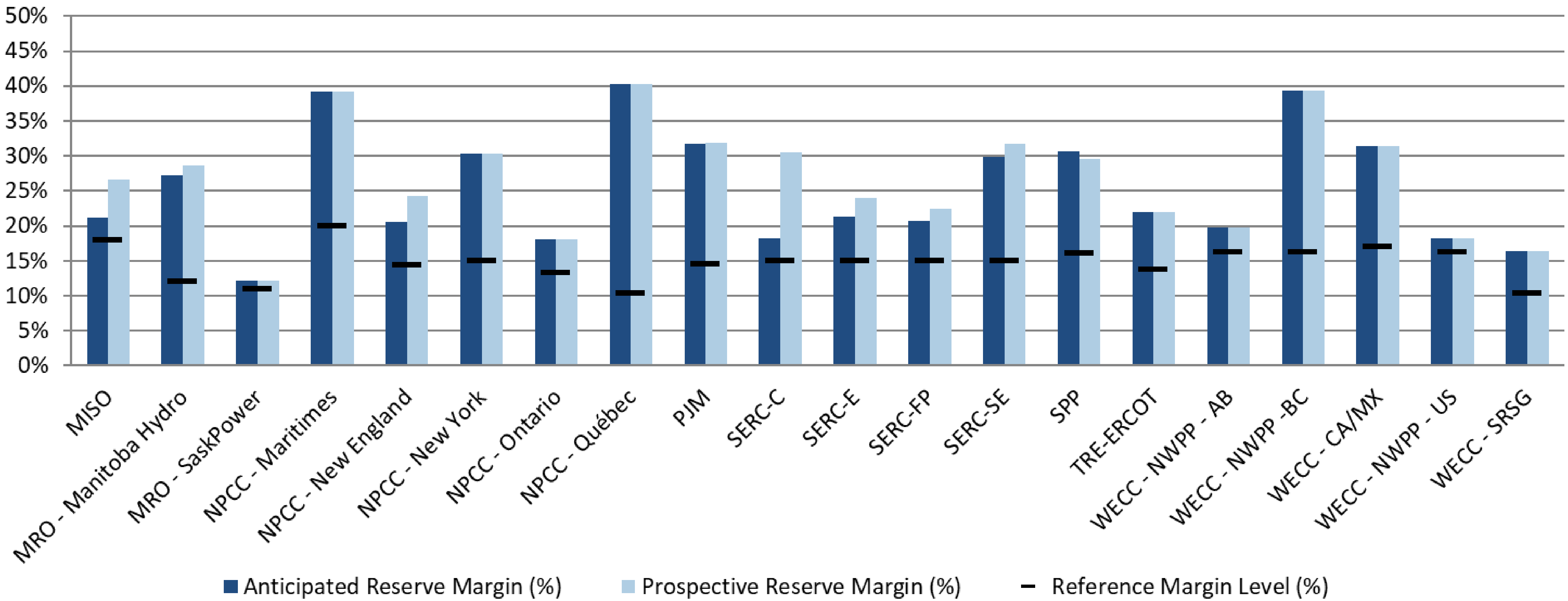
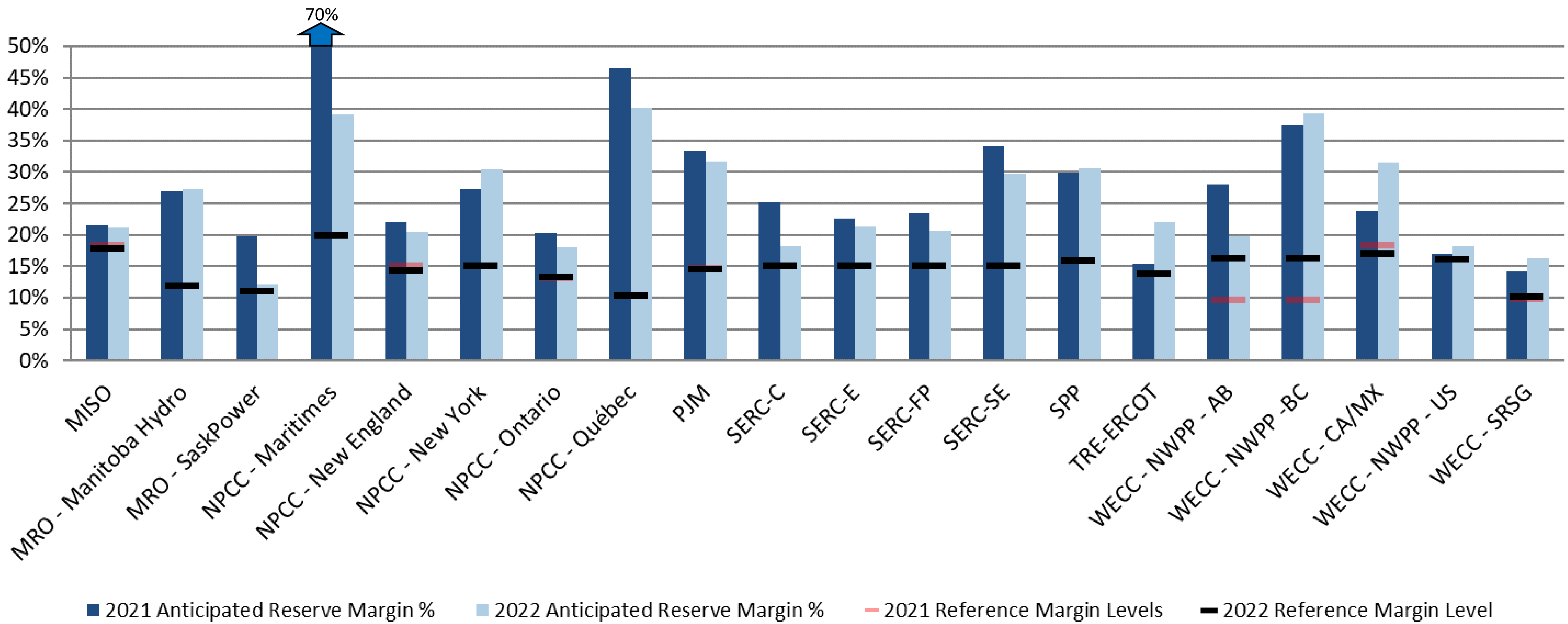


Figure 9: Summer 2022 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[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.

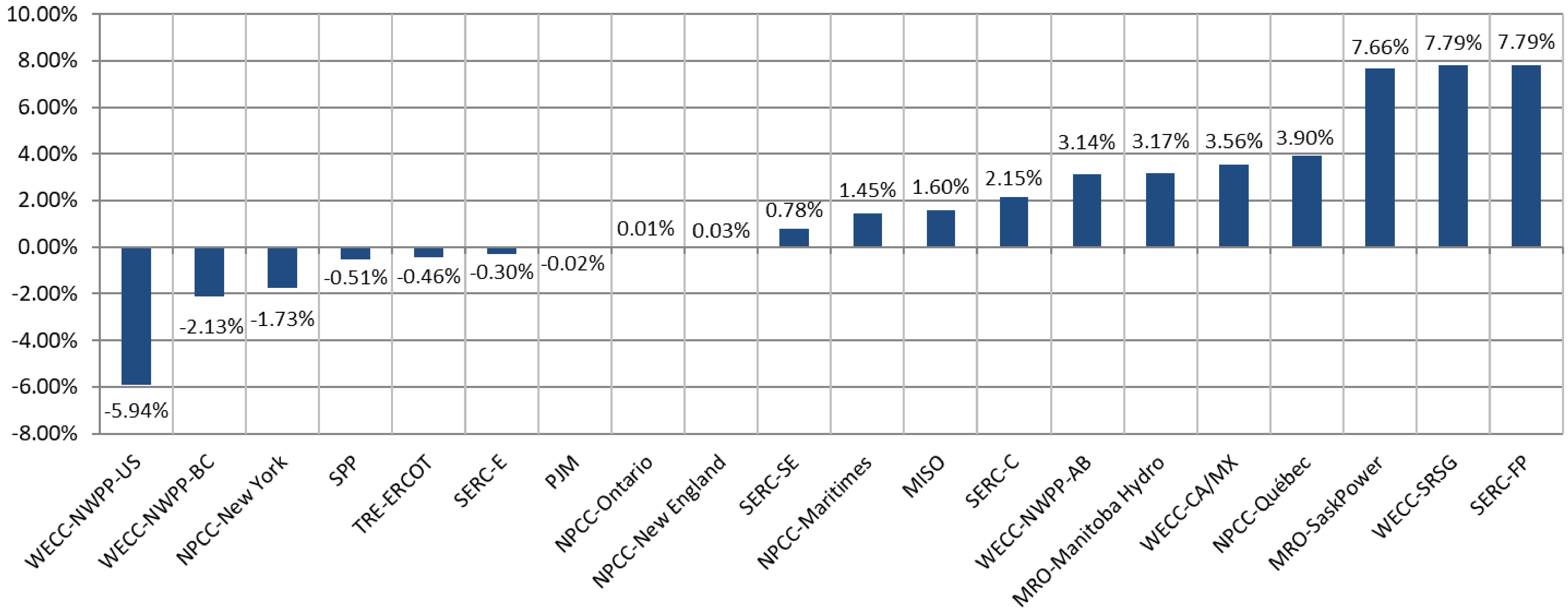


Figure 11: Change in Net Internal Demand: Summer 2021 Forecast Compared to Summer 2022 Forecast

[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%