NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2023 Long-Term Reliability Assessment

December 2023

[Infographic] | [Video]

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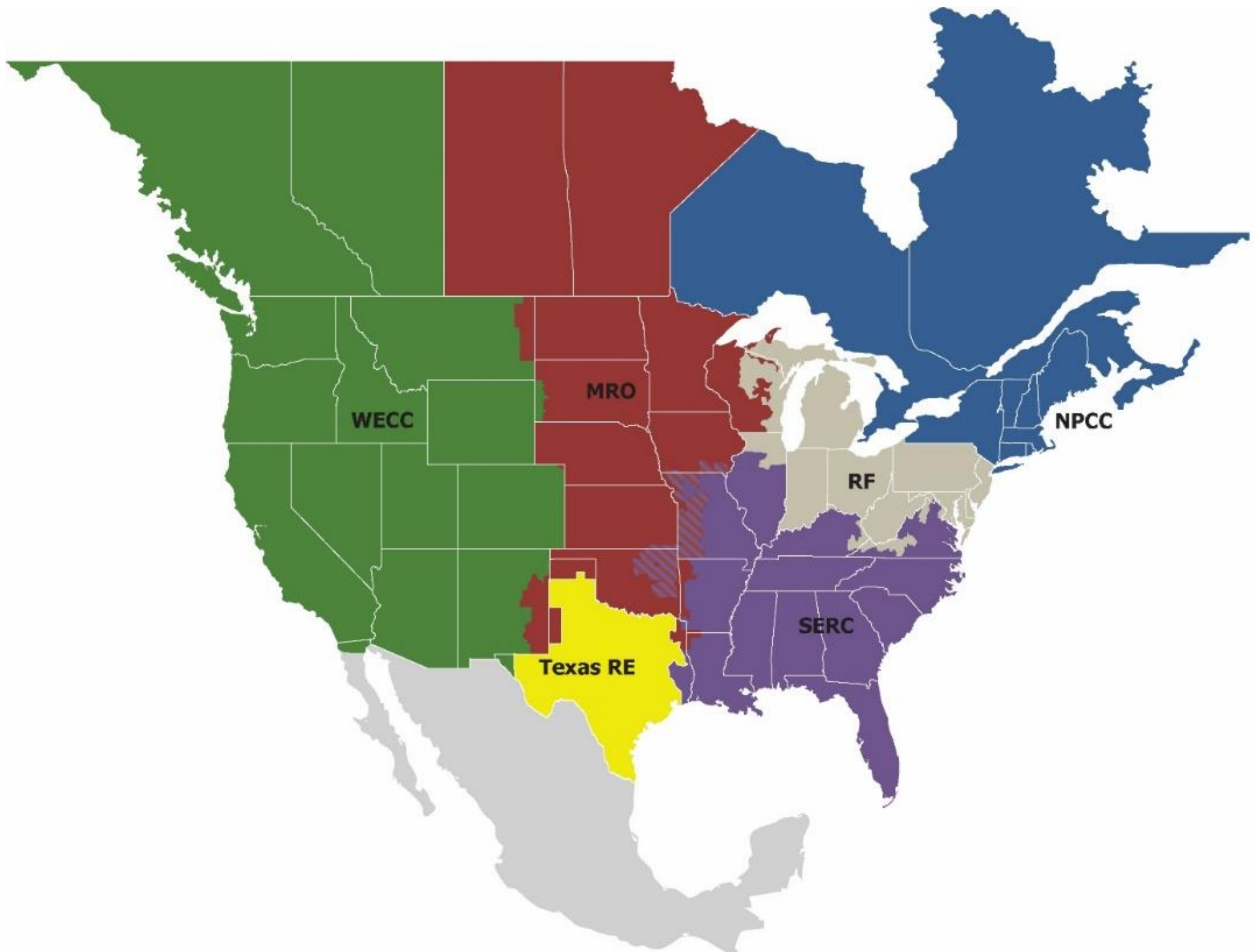
Preface

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 NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

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

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



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

About this Assessment

NERC is a not-for-profit international regulatory authority with the mission 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 North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides 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 NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate 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, Reliability Assessment Subcommittee 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 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] this is 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 2023 about known system changes with updates incorporated prior to publication. This *2023 LTRA* assessment period includes projections for 2024–2033; however, some figures and tables examine data and information for the 2023 year. This 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 the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical 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 NERC's 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 electric 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 from each Regional Entity is 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, 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 Regional Entity, 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** section 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

Assumptions

In this *2023 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 2023. 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 Regional Entity's self-assessment.
- Generation 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.

Reading this Report

This report is compiled into two major parts:

- A reliability assessment of the North American BPS with the following goals:
  - 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
- A regional reliability assessment that contains the following:
  - 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).

Executive Summary

The North American BPS is on the cusp of large-scale growth, bringing reliability challenges and opportunities to a grid that was already amid unprecedented change.[7] Key measures of transmission development and future electricity peak demand and energy needs, which NERC tracks and reports annually in the LTRA, are rising faster than at any time in the past five or more years. New resource projects continue to enter the interconnection planning process at a faster rate than existing projects are concluded; this increases the backlog of resource additions and prompts some Regional Transmission Organizations (RTO) and Independent System Operators (ISO) to adapt their processes to manage expansion. Industry faces mounting pressures to keep pace with accelerating electricity demand, energy needs, and transmission system adequacy as the resource mix transitions.

This *2023 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 year; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal as well as extreme conditions; it is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. NERC's assessment makes use of the latest demand forecasts, resource levels, and area transfer commitments along with collected information on expected generator retirements, resource additions, and demand-side resources.

This assessment provides clear evidence of growing resource adequacy concerns over the next 10 years (**Figure 1**). Capacity deficits are projected in areas where future generator retirements are expected before enough replacement resources are in service to meet rising demand forecasts. Energy risks are projected in areas where the future resource mix could fail to deliver the necessary supply of electricity under energy-constrained conditions. For example, subfreezing temperatures can create energy-limiting conditions by disrupting the natural gas fuel supplies to generators, leading to fuel-related derates or outages and potentially insufficient electricity supply. Furthermore, disruptions in electricity supplies can further exacerbate the availability of natural gas, which is dependent on the delivery of this electrical energy. Periods of low wind are another example of potentially energy-constrained conditions if the resource mix is not sufficiently balanced with dispatchable resources to prevent electricity shortfalls. While the outlook is improving for some assessment areas where resource additions and delayed generator retirements are alleviating previously identified near-term supply shortfalls, a growing number of areas in North American face resource capacity or energy risks over this assessment period. See **Risk Categories** for a general overview of each of the three categories.

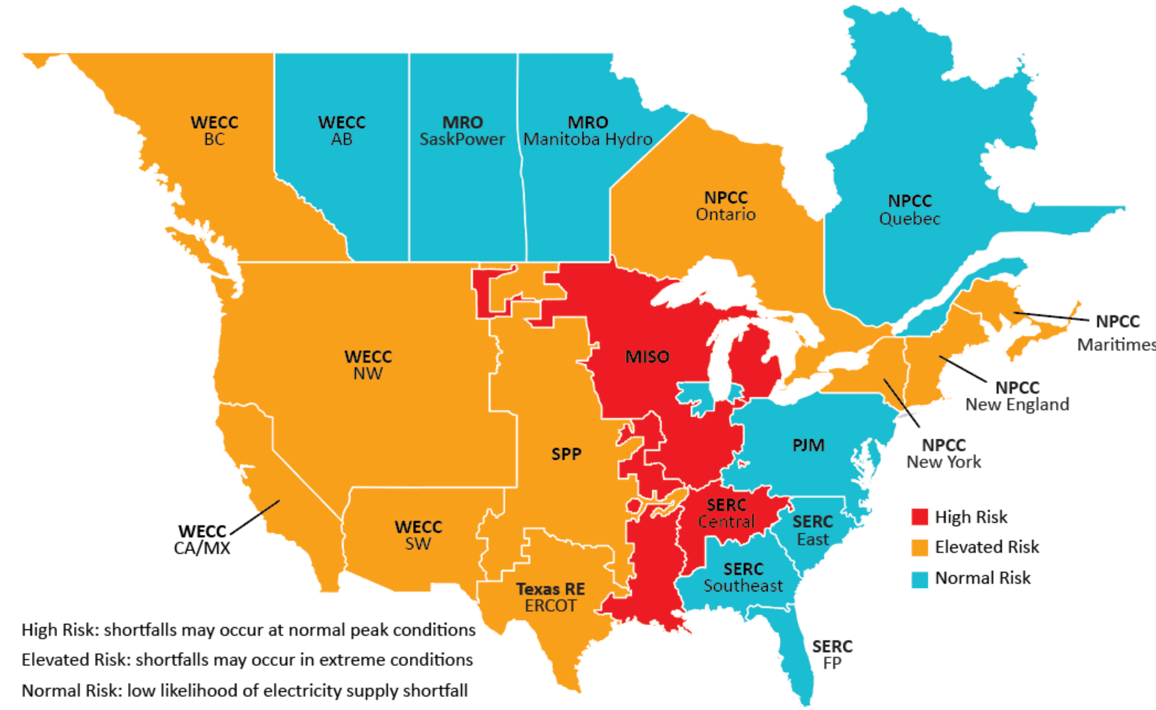


Figure 1: Risk Area Summary 2024–2028[8]

The following pages will provide overviews of each of the risk areas (i.e., high, elevated, and normal).

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[7] As discussed throughout this report and in other NERC reliability assessments and reports, the North American BPS is undergoing a rapidly changing resource mix and the introduction of new technologies affecting how the system is planned and operated. NERC reliability assessments and the ERO Reliability Risk Priorities Report can be found at these locations: Reliability Assessments and Reliability Issues Steering Committee

[8] The Capacity and Energy Risk Assessment is focused on the first five years of the assessment period. Capacity, demand, and reserve margin information covering the entire assessment period can be found in the **Regional Assessments Dashboards** pages.

High Risk Areas[9]

Most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather; however, areas that are red (high risk) in Figure 1 do not meet resource adequacy criteria, such as the 1-day-in-10-year load-loss metric during periods of this assessment period. This indicates that the supply of electricity for these areas is more likely to be insufficient in the forecast period and that more firm resources are needed. See **High Risk Area Details** for additional information. The following are details on the two high risk areas:

- **Midcontinent Independent System Operator (MISO):** Market responses to higher capacity prices in 2022 and new resource additions have overcome the planning reserve deficits that were projected to occur in 2023 and reported in the *2022 LTRA*. In this *2023 LTRA*, MISO's summer anticipated reserve margin (ARM) is projected to be above Reference Margin Levels (RML) established by MISO for reliability through the 2027 summer. However, beginning in 2028, MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur despite the addition of new resources that total over 12 GW. See **MISO** dashboard pages for more information.

- **SERC-Central:** There is a potential shortfall in planned reserves over the 2025–2027 period as demand forecasts increase faster than the transitioning resource mix grows. This assessment area will add over 7 GW of natural gas generation and retire over 5 GW of coal generation over the period. Nearly 4 GW of Bulk Electric System (BES)-connected solar projects are expected in the next 10 years. The period of projected shortfall is occurring in a mid-point of the assessment period from generator retirements that are currently slated to take place before new resources are added. SERC-Central was not identified as a risk area in the *2022 LTRA*. See **SERC-Central** dashboard pages for more information.

Elevated Risk Areas[10]

Extreme temperatures and prolonged severe weather conditions are increasingly impacting the BPS. Extreme heat and subfreezing temperatures can impact the BPS by increasing electricity demand and threatening electricity supplies by forcing vulnerable generation offline and simultaneously disrupting the flow of the natural gas fuel supply to generators. While a given area (see **Figure 1**) may have sufficient capacity to meet resource adequacy requirements, it may not have sufficient availability and energy from resources during extreme and prolonged weather events and abnormal atmospheric conditions (i.e., smoke, smog, and wind extremes that affect output from solar and wind resources). Therefore, long-duration extreme weather events increase the risk of electricity supply shortfalls. See **Elevated Risk Area Details** for additional information.

As forecasted peak electricity demand rises across the BPS, many areas are also experiencing increasing complexity in load models that adds to operating risk. Extreme heat and cold temperatures and irregular weather patterns can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar photovoltaic (PV) distributed energy resources (DER) add to the load forecast uncertainty. Underestimating electricity demand prior to the arrival of extreme temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice; this can expose Balancing Authorities (BA) to potential resource shortfalls. Electrification and DER trends can be expected to further contribute to demand growth and sensitivity to weather patterns.

Electricity supplies can decline in extreme weather for many reasons:

- Generators that are not designed or prepared for severe cold or heat can be forced off-line in increasing amounts.
- Wide area weather events can also impact multiple balancing and transmission operations simultaneously that limit the availability of transfers.

[9] An assessment area is deemed to be "high risk" when it fails to meet the established resource adequacy target or requirement. The established resource adequacy target is not established by NERC, but instead by the prevailing regulatory authority or market operator. Generally, these targets/requirements are based on a 1-day/event load-loss in a 10-year planning requirement. High risk areas have a probability of load shed greater than the requirement/target. Simply said, high risk areas do not meet resource adequacy requirements.

[10] An assessment area is deemed to be "elevated risk" when it meets the established resource adequacy target or requirement, but the resources fail to meet demand and reserve requirements under the probabilistic or deterministic scenario analysis. The established resource adequacy target is not established by NERC, but instead the prevailing regulatory authority or market operator. Simply put, elevated risk areas meet resource adequacy requirements, but they may face challenges meeting load under extreme conditions.

- Fuel production or transportation disruptions could limit the amount of natural gas or other fuels available for electricity generation.
- Wind, solar, and other variable energy resource (VER) generators are dependent on the weather.

Areas in orange (elevated risk) in **Figure 1** meet resource adequacy criteria and have sufficient energy and capacity for normal forecasted conditions, but they are at risk of shortfall in extreme conditions:

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  NPCC-Maritimes: Since the *2022 LTRA*, winter peak demand forecasts for this assessment area have risen. As a result, ARMs are currently projected to fall below the RML of 20% beginning in 2026. The small projected shortfall in planning reserves (120 MW or less over the five-year period) can be managed through supply procurements to reach resource adequacy targets. However, supply shortfalls are more likely to occur in the Maritimes province during wide-area heat events and extreme winter storms; this stresses demand and internal resources and puts external transfer assistance at risk of curtailment. NPCC-Maritimes was not identified as a risk area in the *2022 LTRA*. See the **NPCC-Maritimes** dashboard pages for more information.
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  NPCC-New England: As reported in prior LTRAs and Winter Reliability Assessments (WRA), a persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell, or a series of cold spells, given the existing resource mix and regional fuel delivery infrastructure. ISO-New England's (ISO-NE) latest projections for winter peak demand show the highest growth rates in North America (3.46% compound-annual growth rate (CAGR) over this assessment period), heightening concerns for potential winter supply shortfalls toward the later part of this assessment period. Electrification of the transportation and heating sectors are primary drivers of the increase in demand forecast. New resources in ISO-NE's interconnection request queue do not generally offer the same reliability benefits in winter as the generation resources that are retiring (e.g., dispatchability, stored fuels). See the **NPCC-New England** dashboard pages for more information.
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  NPCC New York: Reliability studies performed by the New York Independent System Operator (NYISO) have identified potential shortfalls starting in 2025 in New York City, prompting NYISO to solicit for market-based and regulated backstop solutions (i.e., generation, DR, or transmission, or combinations). The need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation types in New York City that are affected by a state law to reduce nitrogen oxide emissions. The deficiency could be significantly greater during a summer heatwave. NPCC New York was not identified as a risk area in the *2022 LTRA*. See the **NPCC-New York** dashboard pages for more information.
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  NPCC-Ontario: Planned and contracted resource additions have improved the resource adequacy outlook since the *2022 LTRA.* At that time, NERC projected that shortfalls could occur beginning in 2025. In this *2023 LTRA*, reserve margins are projected to remain above Ontario's RMLs throughout the first five years. The improved outlook is the result of 1,600 MW of upgrades and expansions to natural-gas-fired generators and new BESS projects as well as a recent memorandum of understanding with Québec for 600 MW of firm summer capacity beginning in 2025. NPCC-Ontario meets resource adequacy criteria but with as little as 300 MW of surplus summer capacity starting in summer 2028. Extreme conditions that cause peak demand to exceed forecasts or above normal outages to occur could expose the area to risks of capacity shortfall. Additional capacity from the Independent Electricity System Operator's (IESO) future annual capacity auctions and ongoing procurements will continue to reduce these risks. See the **NPCC-Ontario** dashboard pages for more information.
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  Southwest Power Pool (SPP): Since the *2022 LTRA*, projected reserve margins for the assessment period have declined while the RML of reserves needed for maintaining reliability has risen at the same time. Consequently, SPP's surplus capacity over the next five years will fall sharply. Lower reserve margins are driven by generation retirements (1,500 MW since the *2022 LTRA)* and rising peak demand forecasts. SPP raised the RML from 16% to 19% in 2023, LSEs in the RTO area to procure more resource capacity for the same amount of load. Energy shortfalls can occur in SPP when high demand coincides with low wind or above-normal generator outages. See the **SPP** dashboard pages for more information.

- **Texas RE-ERCOT:** Generation resources, primarily solar PV, continue to be added to the grid in large quantities, increasing ARM but also elevating concerns of energy risks. With demand forecast to rise steadily, the future resource mix is likely to have the lowest reserve levels during off-peak periods when solar PV resource output is diminished. These include hot summer evenings as well as fall and spring months when dispatchable thermal generation is performing scheduled maintenance. Extreme winter weather, such as Winter Storm Uri in February 2021, remains a serious concern that warrants continued efforts to ensure that generators and fuel supplies are available and capable of performing in severe conditions. Without provisions for electric grid reliability, new and proposed Environmental Protection Agency (EPA) rules could heighten the risk of thermal unit retirements before solutions to resource adequacy and system planning issues are in place. See the **Texas RE-ERCOT** dashboard pages for more information.

- **British Columbia (WECC-BC):** Forecasted peak demand growth is causing a decline in reserve margins and reduced surplus capacity for managing periods of above-normal demand. Energy shortfall risks in the WECC-BC assessment area are associated with extreme weather conditions that cause periods of above-normal demand to coincide with lower-than-normal resource output. Probabilistic assessment (ProbA) results show little energy risk in 2024; however, load-loss and unserved energy risks increase in 2026 as forecasted demand increases and natural-gas-fired generation retires. WECC-BC was not identified as a risk area in the *2022 LTRA*. See the **WECC-BC** dashboard pages for more information.

- **WECC U.S. Assessment Areas:** Throughout this area, both demand and resource variability are projected to continue increasing as the resource mix transitions and more DERs connect to the distribution system. In normal conditions, the expected demand and resource variability is balanced across the area as excess supply from one part of the system is delivered through the transmission network to places in need. However, more extreme summer temperatures that stress large portions of the Interconnection reduce the availability of excess supply for transfer while also reducing the transmission network's transfer capability:

  - **California/Mexico (WECC-CA/MX):** Resource additions, generator uprating, and service extensions have helped alleviate near-term capacity risks and lower the area's reliance on imports to meet high demand. Since the *2022 LTRA*, WECC's probabilistic analysis indicates that risks of unserved energy and load loss in 2024 have fallen to negligible levels. However, loss-of-load and unserved energy risks emerge in 2026 concentrated in the July–September period and are primarily associated with extreme weather conditions. ARMs continue to rise from levels reported in NERC's previous LTRAs as new resources are added, primarily solar PV, hybrid-solar PV, and BESS resources. See the **WECC-CA/MX** dashboard pages for more information.

  - **Northwest (WECC-NW)** and **Southwest (WECC-SW):** Like WECC-CA/MX, WECC-NW and WECC-SW are projected to be at risk of resource shortfalls during extreme summer weather conditions after 2024. Although the assessment areas are projected to have sufficient capacity to meet forecasted peak demand throughout this assessment period, dispatchable generation declines as generators retire starting in 2026. The resulting resource mix is more variable and has a risk of supply shortfalls during extreme summer conditions emerge in WECC's probabilistic analysis. See the **WECC-NW** and **WECC-SW** dashboard pages for more information.

Normal Risk Areas

Normal risk areas are shown in blue (see **Figure 1**). In these areas, resource adequacy criteria are met, and it is unlikely for electricity supply shortfalls to occur even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). See **Normal Risk Area Details** for additional information.

Changing Resource Mix and Reliability Implications

Wind, solar PV, and hybrid generation are projected to be the primary additions to the resource mix over the 10-year assessment period; this leads the continued energy transition as older thermal generators retire. Maintaining a reliable BPS throughout the transition requires unwavering attention to ensure the resource mix satisfies capacity, energy, and essential reliability service (ERS) needs under designed conditions. It will also require significant planning and development of the interconnected transmission system to have a deliverable electricity supply from new resources to changing types of loads and the ability to withstand system contingencies.

In this LTRA, NERC accounted for over 83 GW of fossil-fired and nuclear generator retirements that are currently anticipated through 2033. An additional 30 GW of fossil-fired generators have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. These additional retirements can exacerbate energy, capacity, or ERS issues in high risk (red) and elevate risk (orange) areas and potentially affect the projected sufficiency of resources in normal risk (blue) areas (**Figure 1**). Environmental regulations and energy policies that are overly rigid and lack provisions for electric grid reliability have the potential to influence generators to seek deactivation despite a projected resource adequacy or operating reliability risk; this can potentially jeopardizing the orderly transition of the resource mix.[11] For this reason, regulators and policymakers need to consider effects on the electric grid in their rules and policies and design provisions that safeguard grid reliability.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period are higher than at any point in the past decade. Electrification and projections for growth in electric vehicles (EV) over this assessment period are a component of the demand and energy estimates provided by each assessment area. Since the *2022 LTRA*, peak season CAGR has risen in nearly all assessment areas, contributing to an overall trend to lower reserve margins. Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as heating system and transportation electrification influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, requiring resource and system planners to shift the focus of adequacy planning. Concentrated growth and the emergence of new types of loads are occurring in many areas. These growth trends bring additional challenges for resource and transmission adequacy. Planners and operators can prepare by considering robust demand and energy scenarios, carefully monitoring and refining demand forecasts, and developing operational tools for peak load management.

Transmission Trends

The amount of BPS transmission projects reported to NERC as under construction or in planning for construction over the next 10 years has increased, indicating an overall increase in transmission development. New transmission projects are being driven to support new generation and enhance reliability. Siting and permitting challenges continue to inflict delays in transmission expansion planning. Regional transmission planning processes are adapting to manage the energy transition, but impediments to transmission development remain.

Conclusions and Recommendations

The energy and capacity risks identified in this *2023 LTRA* underscore the need for reliability to be a top priority for energy policymakers, regulators, and industry. Growing the reliable BPS will involve doing the following four things, numbered only for identification:

1. **Add new resources with needed reliability attributes and make existing resources more dependable.** As BPS resources grow to meet rising demand and the resource mix changes, IBR performance issues as well as generator and fuel vulnerabilities to extreme temperatures must be addressed to have a reliable electricity supply:
    - New wind and solar PV resources use inverters to convert their output power onto the grid, and the vast majority of resource inverters are susceptible to tripping or power disruption during normal grid fault conditions; this makes the future grid less reliable when more resources are inverter-based.
    - Natural-gas-fired generators are essential for meeting demand; they are dispatchable at any hour and provide a consistent rated output under a wide range of conditions. However, sufficient natural gas fuel supplies cannot be assured without better reliability measures and the effective coordination between the operators and planners of both electricity and natural gas infrastructures.
    - Reducing risks to electricity supplies in extreme hot and cold temperatures requires generating resources that are up to the task. However, natural-gas-fired generators, natural gas fuel supplies, and wind resources (which are becoming increasingly common)

[11] The EPA is implementing, has finalized, or has proposed six rules that impact the fossil-fired generators: Coal Combustion Residuals (being implemented), revised Effluent Limitations Guidelines (proposed), revised Mercury and Air Toxics Standards (proposed), Good Neighbor Rule (finalized), Carbon Rule (proposed), and Regional Haze (being implemented).

have proven vulnerable and unable to meet demand during winter storms over the past decade.

- Additionally, to reliably grow the BPS, generator retirements over the 10-year assessment period of this *2023 LTRA* need to be carefully evaluated. State and provincial resource adequacy stakeholders and policymakers need to ensure that resource plans account for growing electricity demand and load profiles as well as the future resource portfolio's capabilities to provide essential grid reliability services. They must have effective measures that can be implemented to prevent loss of resources that are needed for resource and energy adequacy, grid reliability, and system restoration.

2. **Expand the transmission network to deliver supplies from new resources and locations to serve changing loads.** A strong, flexible transmission system that is capable of coping with a wide variety of system conditions is key for the reliable supply and delivery of electricity. The rapidly changing resource mix requires access and deliverability of new resources—including transmission availability—to maintain reliability:
   - Transmission development is needed to connect resources to load and to adapt to a future system demand profile that will be influenced by EV charging, electrification in heating, large industrial loads and data centers, and the behavior of large flexible loads. The capability for electricity supplies to be transferred between areas may play a significant part in overall energy adequacy when the system may have highly variable electricity supply resources and more weather-sensitive demand.
   - Additionally, introducing new resource types into the system and ensuring that the planned system can be operated within reliability criteria requires engineering analysis that will be increasingly complex. Transmission planning processes are adapting to overcome challenges and the speed of development; however, backlogs remain.
3. **Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.** The addition of variable resources (primarily wind and solar PV) and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. To ensure energy shortfall risks are identified and addressed, resource contributions to serving load must be accurately represented in resource planning and operating models as well as in the design of wholesale electricity market designs:
   - Resource and system planners must have robust tools and capabilities for assessing energy needs, extreme weather scenarios, and grid stability. Planning Reserve Margins can fail to identify energy risks that stem from low VER output or generator fuel supply issues, making them unsuitable as a sole basis of resource adequacy. Resource planners and wholesale markets must use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. NERC and the industry should also use wide-area assessments capable of accurately modeling interregional transfers to improve resource adequacy and energy risk assessments.
   - Geographically diverse wind and solar resources and loads can help reduce energy risks but require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms.
   - Natural gas supply infrastructure and the BPS form an interconnected energy system that requires a high degree of coordination and integration. The operation of this interconnected energy system can be disrupted when natural gas fuel supplies are not available for electricity generation as well as when electricity is not available to operate electricity-driven compressors and other critical infrastructure components in the natural gas supply chain. The potential for extreme cold temperatures to have wider impact because of the interconnected nature of the electric and natural gas systems makes integrated planning and effective coordination imperative.
   - Explosive growth in rooftop solar PV and other resources on distribution networks add complexity to planning and operating models and market designs that require visibility and coordination across distribution and BPS jurisdictions. Large flexible loads and demand-side management programs offer reliability benefits by providing operators with another resource for managing peak loads; however, operating models and mechanisms for control must be in place.
4. **Strengthen relationships among reliability stakeholders and policymakers.** Making informed policies and decisions in matters that have the potential to affect electric grid reliability requires a high level of awareness as future electricity resource reserves shrink in the face of demand growth and the interconnected nature of the electric and natural gas systems are more pronounced:
   - Initiatives like the North American Energy Standards Board Gas Electric Harmonization Forum—which is comprised of a broad cross section of natural gas and electricity stakeholders and experts; this forum was assembled to address weaknesses identified in 2021's Winter Storm Uri and 2022's Winter Storm Elliott. The NAESB put forward several recommendations that, if implemented today, would enable BPS operators to have a more reliable and fuel-secure generation mix and be in a better position to maintain the integrity of the BPS during extreme weather events, such as Winter Storm Elliott.

Initiatives like this are essential to come up with structural solutions to risks that arise from critical interdependencies.

- The Memorandum of Understanding between the U.S. Department of Energy (DOE) and the U.S. EPA to foster interagency cooperation and consultation to support electric grid reliability is an encouraging acknowledgement of the need for environmental policies to carefully consider electric grid reliability and provides a path for flexibility provisions to be addressed.[12]
- There is a need for dialogue among a broad group of stakeholders when policies and regulations have the potential to affect future electricity supplies, demand, and the development of electricity and natural gas resources and infrastructure. Regulations that have the potential to accelerate generator retirements or restrict operations must have sufficient flexibility and provisions to support grid reliability. The need for close coordination is further reinforced by the expanding interdependencies with other critical infrastructure sectors (i.e., communications, water and wastewater, transportation, critical manufacturing, and finance).[13]

Specific and actionable recommendations are contained in the **Recommendations: Details** section of this report with the same numbers to identify them. A summary of ERO ongoing activities and resources that address applicable recommendations is included in the **ERO Actions Summary** section.

[12] DOE-EPA Electric Reliability MOU
[13] 2023 ERO Reliability Risk Priorities Report

Recommendations: Details

The following numbered recommendations are additional details for the Executive Summary Conclusions and Recommendations with the same identifying numbers.

1. **Add new resources with needed reliability attributes and make existing resources more dependable:**

   - **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for over 70% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California and similar events have occurred in new geographic areas as recently as the summer of 2023.[14] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[15] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[16] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 991, the ERO and industry should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[17,18]

   - **Improve the performance of the generating fleet in extreme weather:** The ERO and industry need to prioritize the development of Reliability Standard requirements to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[19] Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[20]

   - **Mitigate fuel-related risks to electricity generation (fuel assurance)**: In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, 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.[21]

   - **Carefully manage generator deactivations:** State and provincial regulators and ISOs/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the DOE should use its 202(c) authority in support of electric system operators.

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[14] See the ERO's extensive IBR event reporting here: NERC Major Event Reports

[15] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.

[16] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide

[17] NERC IBR Activities

[18] FERC Order No. 901 - Final Rule Reliability Standards to Address Inverter-Based Resources

[19] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*

[20] Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott

[21] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

2. **Expand the transmission network to deliver supplies from new resources and locations to serve changing loads:**
   - **Develop the transmission network:** ISOs/RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.
   - **Assess interregional transfer capabilities and their contribution to BPS reliability.** Studies of interregional transfers and transfer capability under a range of scenarios can provide insight into potential benefits of transmission development on grid reliability. It is important for NERC and the industry to complete the interregional transfer capability study directed in the Fiscal Responsibility Act of 2023 and share the results with legislators, regulators, and policymakers.[22] NERC should also incorporate insights and study approaches from the interregional transfer capability study to better account for interregional transfers in energy and capacity risk assessments.
3. **Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system:**
   - **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models.** Resource planners and wholesale market designers are developing new processes for assigning the contribution of resources to meeting demand in most areas with growing wind and solar PV resources. Earlier this year, MISO implemented seasonal resource adequacy auctions (spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. Other ISOs and RTOs are exploring similar initiatives. Some assessment areas are implementing effective load-carrying capacity (ELCC) methods that involve probabilistic study to assign the capacity contribution of resources. These ELCC methods must address the risks and shortcomings in the present modeling described in this *2023 LTRA.* Specifically, the statistical representation of capacity that has variable and uncertain fuel can be problematic when combined in a reserve margin evaluation with capacity that has firm fuel and is highly reliable. Planners and operators must continue updating processes, tools, and techniques to keep pace with the changing resource mix. Among the changes needed is the consideration of the energy contributions that each resource type is expected to provide in order to identify periods of potential energy shortfalls. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.
   - **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** Planning Reserve Margins are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Industry and research partners should focus on developing tools, models, and methods for including a wide-area view of energy transfers in resource adequacy studies. Additionally, the ERO must develop and implement analytical approaches to incorporate natural-gas fuel supply risks in NERC reliability assessments.
   - **Maintain sufficient amounts of flexible resources**: To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV 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. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators.[23]
   - **Develop tools for assessing extreme weather risks:** Planners are finding it necessary to have improved tools and methods to study wide-area, long duration extreme weather risks and other low-likelihood, extreme events. Scenario planning is needed to ensure appropriate evaluation of likelihood, consequence, and potential mitigations to enhance reliability and resilience of the BPS. Traditional resource adequacy models and approaches rooted in a loss-of-load expectation (LOLE) of 1 day-in-10-years do not account for the essential role that electricity plays in modern society, and normal demand

[22] Fiscal Responsibility Act of 2023
[23] NERC ERS Measure 6 Forward Tech Brief

distributions appear to be ill-suited for describing the extremes of changing weather patterns. NERC, industry, and research partners should collaborate to develop models and approaches for studying the risks to electricity supplies, including natural gas fuel availability, from wide-area and long-duration extreme weather conditions. Such capabilities for rigorously studying the impact of extreme weather will enable a more accurate assessment of the risks and provide for the development of effective measures for resilience.

- **Include extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system.

- **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distribution resources must also be a priority in many areas. Growth of DERs promise both opportunities and risks for reliability. Increased DER penetrations can improve local resilience at the cost of reduced operator visibility into loads and resource availability. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISOs/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.[24]

4. Strengthen relationships among reliability stakeholders and policymakers:

- **The ERO and industry partners need to expand strategic engagements with federal, state, and provincial regulators and policymakers:** These officials have jurisdictional authority to make key decisions that affect reliability, resource adequacy, and infrastructure development.

- **The ERO, regulators, and industry partners need to work together:** Special emphasis needs to be placed on mechanisms to ensure the reliable delivery of natural gas fuel supplies for electricity generation as well as to act on the recommendations in *The FERC-NERC-Regional Entity Staff Report: Inquiry into Bulk Power System Operations December 2022 Winter Storm Elliott*.

[24] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

Capacity and Energy Assessment

Conditions for tighter resource adequacy—characterized by less surplus capacity relative to forecasted demand—have emerged generally across the BPS over the past decade. **Figure 2** shows summer peak resource capacity (top) and forecasted peak demand (bottom) aggregated for all NERC assessment areas at the beginning and the end of the 2012–2032 period. While summer forecasted peak demand increased by 3% since 2012, current on-peak BPS resource capacity decreased by 4%. Furthermore, summer peak demand is forecast to increase another 10% by 2032 while resources are expected to grow modestly by 4%. Lower reserves by this broad and retrospective measure are a coarse indicator that signals a need for stakeholders to pay careful attention to more specific and granular resource adequacy measures and input assumptions.

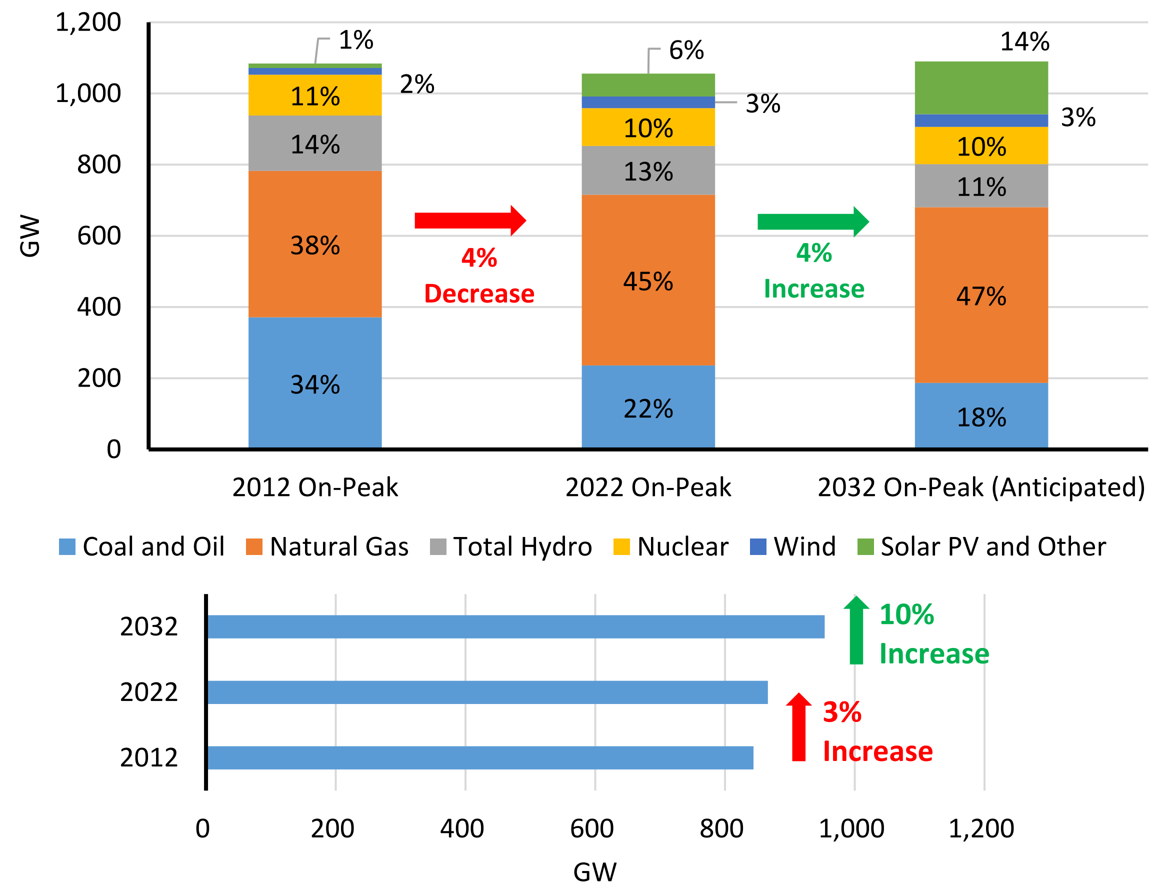


Figure 2: Change in Summer Peak Capacity and Demand Forecast 2012–2032

Assessment Approach

NERC is using two approaches in this *LTRA* to assess future resource capacity and energy risk; both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development:

- Comparing the margin between projected resources and peak net demand, or reserve margin, to an RML that represents the accepted level of risk based on a probability-based loss-of-load analysis.
- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours to identify high risk periods and potential energy constraints resulting in load loss events. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's biennial ProbA are used to identify risk levels. The ProbA was completed in 2022 and published in the *2022 LTRA*. Subsequently, NERC published the *2022 Probabilistic Assessment Regional Risk Scenarios Report* to analyze more extreme area-specific reliability risks and uncertainties with probabilistic methods.[25] This *LTRA* considers both results and updated projections to determine energy risk trends.

See the **Demand Assumptions and Resource Categories** for further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Finding: This *2023 LTRA* Capacity and Energy Assessment section highlights both progress and growing resource adequacy concerns as the resource mix transition continues. Delayed generator retirements and resource additions are alleviating some previously identified near-term capacity shortfalls. However, a growing number of areas in North American face resource capacity or energy risks over the assessment period. Capacity deficits, where they are projected, are largely the result of generator retirements that have yet to be replaced. While some areas have sufficient capacity resources, energy limitations and unavailable generation during certain conditions (e.g., low wind, extreme and prolonged cold weather) can result in the inability to serve all firm demand.

[25] 2022 ProbA Regional Risk Scenarios Report

Risk Categories

An assessment area is high risk (see **Figure 1**) when established resource adequacy targets or requirements are not met during this assessment period. NERC does not establish resource adequacy targets; these are set by regulatory authorities or market operator and are typically based on a 1-day/event load-loss in a 10-year planning requirement. High risk areas have a probability of load shed greater than the requirement/target.

An assessment area is considered an elevated risk when it meets the established resource adequacy target or requirement, but the resources fail to meet demand and reserve requirements under probabilistic or deterministic analysis of conditions that are plausible but more extreme than normal seasonal peaks. More extreme conditions can include temperatures that result in above normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. Simply put, elevated risk areas meet resource adequacy requirements, but they may face challenges meeting load under extreme conditions.

NERC assesses areas as normal risk when resource adequacy criteria are met and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas categorized as Normal Risk are expected to have sufficient resources for plausible extreme conditions, they are not immune to the effects of exceedingly rare severe weather events that simultaneously affect demand and generation or other high-impact, low frequency events.

High Risk Area Details

Most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather. However, the following two areas (listed in order of appearance on the **Regional Assessments Dashboards)** do not meet resource adequacy criteria, such as the 1-day-in-10-year load-loss metric during periods of the assessment period. This indicates that the supply of electricity for these areas is more likely to be insufficient in the forecast period and that more firm resources are needed. See **High Risk Areas** in a previous section for additional information.

MISO

In 2023, MISO transitioned to its first year of seasonal capacity auctions (summer, fall, winter, spring). Market responses to higher capacity prices in 2022 and new resource additions have overcome planning reserve deficits reported in the *2022 LTRA*, and now MISO's summer ARM is projected to be above the RMLs through the 2031 summer (**Figure 3**). Beginning in 2028, MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur and over 12 GW of new resources are added.

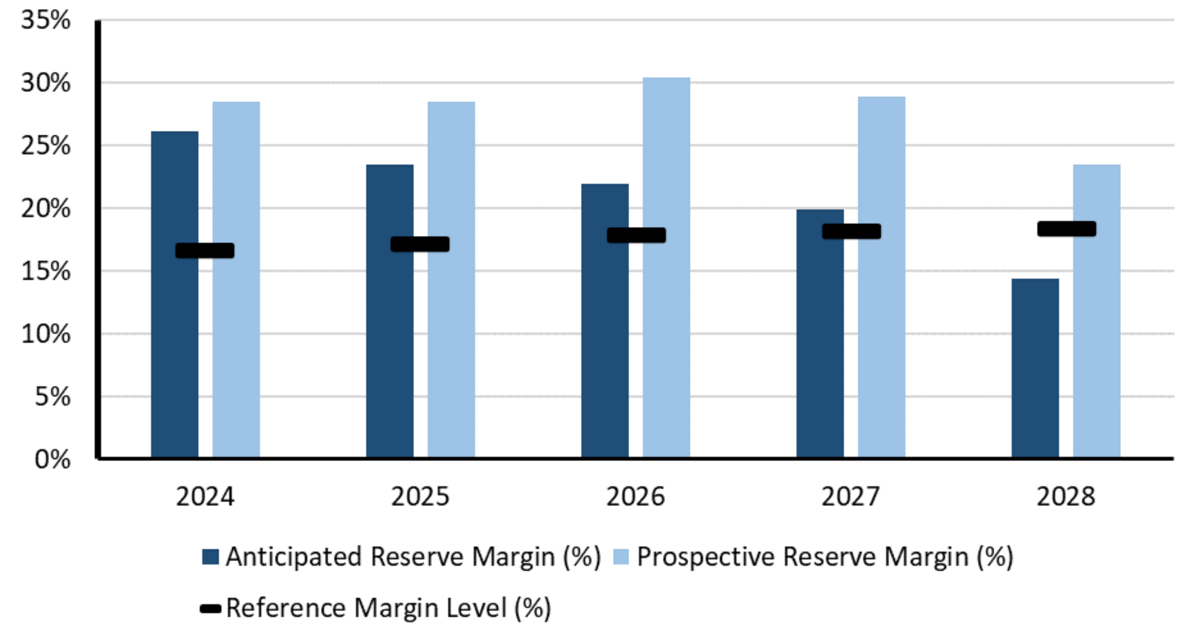


Figure 3: MISO Five-Year Planning Reserve Margin–Summer

MISO's switch to seasonal resource adequacy construct now more effectively identifies risk across the entire year as it makes use of seasonal resource accreditation and seasonal resource adequacy requirements. Resource performance in winter may differ from other seasons (e.g., seasonal wind patterns effect wind generating fleet; thermal generator outage rates vary by season; and solar resources typically have less or no output at times of highest demand in winter). Similarly, demand profiles are different by season. A seasonal RML accounts for these and other factors. Beginning in 2028, MISO's winter ARM is expected to fall below the area's winter RML (1,300 MW shortfall). **Figure 4** shows the steady decline of winter ARMs in MISO and the winter RML. The contrast between the increasing summer ARMs and declining winter ARMs is the result of the changing resource mix. Retiring generators, primarily thermal, are being replaced with solar PV (which has very small capacity contributions in winter) and some wind.

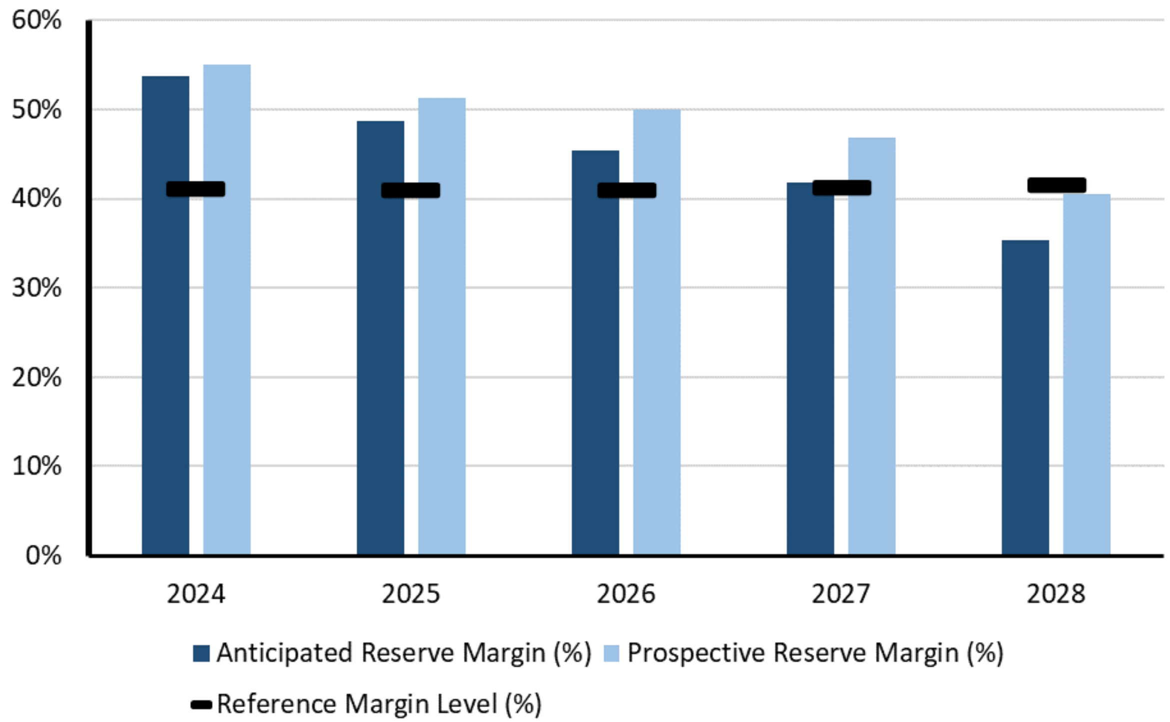


Figure 4: MISO Five-Year Planning Reserve Margin–Winter

Like MISO, other ISO/RTO areas and integrated resource planners are considering or developing seasonal resource adequacy approaches to better respond to anticipated challenges.

SERC-Central

The SERC-Central assessment area faces a potential shortfall in planned reserves over the 2025–2027 period as demand forecasts increase faster than the transitioning resource mix grows (**Figure 5**). The assessment area will add 7,251 MW of natural gas generation and retire 5,159 MW of coal generation over the period. A total of 3,937 MW of BES-connected Tier 1 solar PV projects are expected in the next 10 years. The period of projected shortfall is occurring in a mid-point of this assessment period from generator retirements that are currently slated to take place before new resources are added. Overall, there will be 2,762 MW of net additions and retirements within the next 10 years.

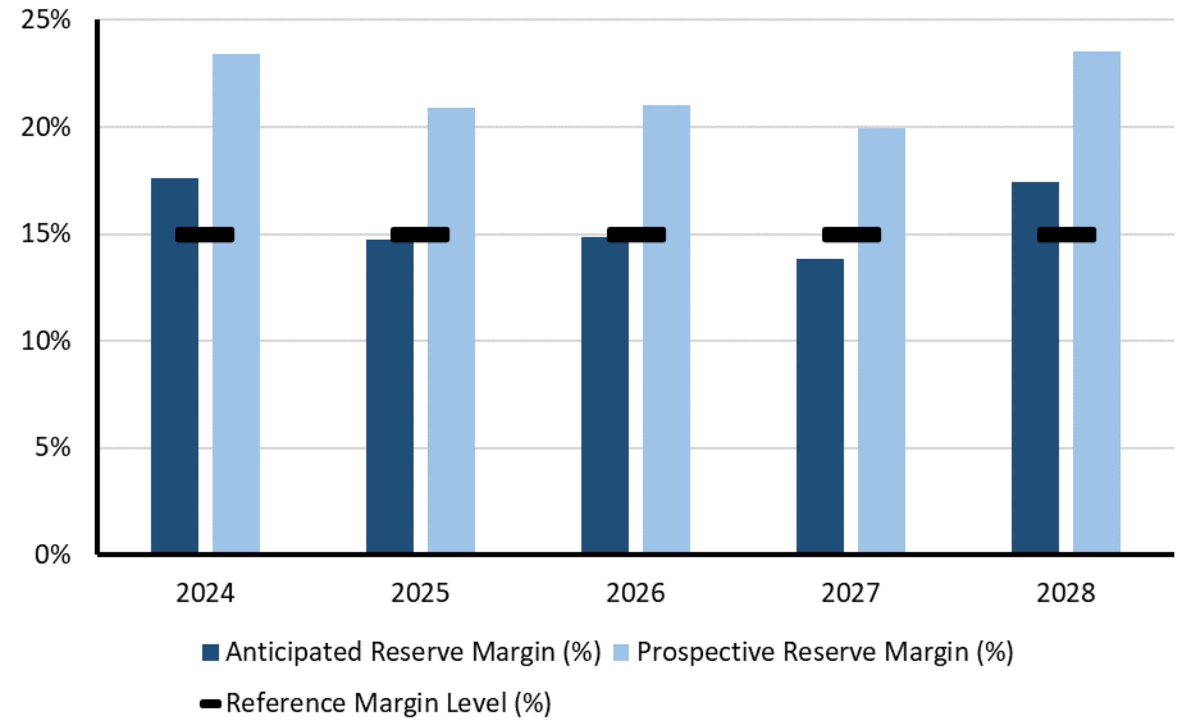


Figure 5: SERC-C Five-Year Planning Reserve Margin

NERC's 2022 ProbA revealed some LOLH (<0.1 hours/year) concentrated in winter. With rising demand projections and relatively unchanged resources, the risk is increasing over this assessment period.

Elevated Risk Area Details

The below areas are projected to meet resource adequacy criteria and have sufficient energy and capacity for normal forecasted conditions but are at risk of supply shortfall in assessed extreme conditions. Areas are listed in order of appearance on the **Regional Assessments Dashboards** section. See **Elevated Risk Areas** in a previous section for additional information.

NPCC-Maritimes

Since the *2022 LTRA*, winter peak demand forecasts for the assessment area have risen. As a result, Anticipated Reserve Margins (ARM) are currently projected to fall below the RML of 20% beginning in 2026 (**Figure 6**). The small projected shortfall in planning reserves (120 MW or less over the five-year period) can be managed through supply procurements to reach resource adequacy targets. However, supply shortfalls are more likely to occur in Maritimes during wide-area heat events and extreme winter storms transfers that stress demand and internal resources and put external transfer assistance at risk of curtailment.

NERC's 2022 ProbA revealed some LOLH (<0.1 hours/year) concentrated in winter. With rising demand projections and relatively unchanged resources, the risk is increasing over this assessment period.

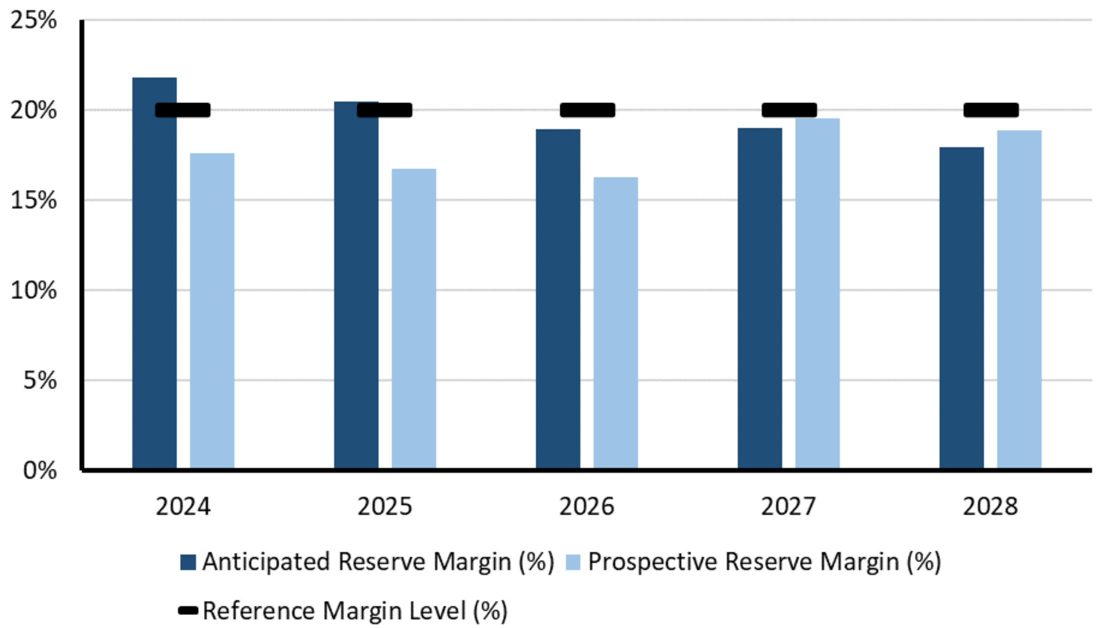
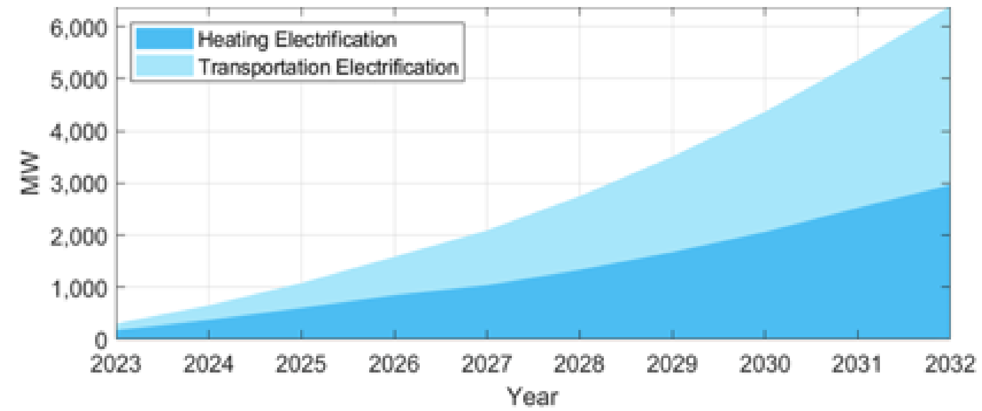


Figure 6: NPCC-Maritimes Five-Year Planning Reserve Margin

NPCC-New England

As reported in prior LTRAs and WRAs, a persistent concern for New England is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. ISO-NE's latest projections for winter peak demand show the highest growth rates in North America (3.46% CAGR over this assessment period), heightening concerns for potential winter supply shortfalls toward the later part of this assessment period. Electrification of the transportation and heating sectors are primary drivers of the increase in demand forecast (See **Figure 7**).



	Transportation Electrification				Heating Electrification		
Year	CELT 2022 (MW)	CELT 2023 (MW)	Change (MW)		CELT 2022 (MW)	CELT 2023 (MW)	Change (MW)
2023	50	116	66		75	175	100
2024	133	271	138		179	370	192
2025	244	473	229		311	601	290
2026	382	726	344		473	848	374
2027	549	1,042	493		668	1,040	372
2028	743	1,404	661		895	1,333	438
2029	967	1,822	855		1,158	1,673	515
2030	1,221	2,293	1,072		1,476	2,063	588
2031	1,497	2,820	1,323		1,831	2,521	691
2032		3,420				2,965	

Figure 7: Electrification Component of Winter Peak Demand Projections (Source: ISO-NE CELT Report 2023)

New resources in ISO-NE's interconnection request queue do not offer the same reliability benefits in general during winter as the generation resources that are retiring or at risk of retiring over this assessment period. Thermal generation with stored fuel is at risk of retirement without fuel-assured replacements. The generation interconnection queue includes over 35 GW capacity; however, it is primarily VERs. More dispatchable, fuel-assured, or long-duration stored energy resources will be required to provide for reliable winter operations as electrification continues in the area.

NPCC New York

ARMs exceed a RML of 15% over the near-term; however, reserve surplus is near zero in 2025 (see **Figure 8**).[26] This leaves little reserve to meet above-normal levels of summer demand or manage high generator outages or loss of imports that can occur during extreme weather events.

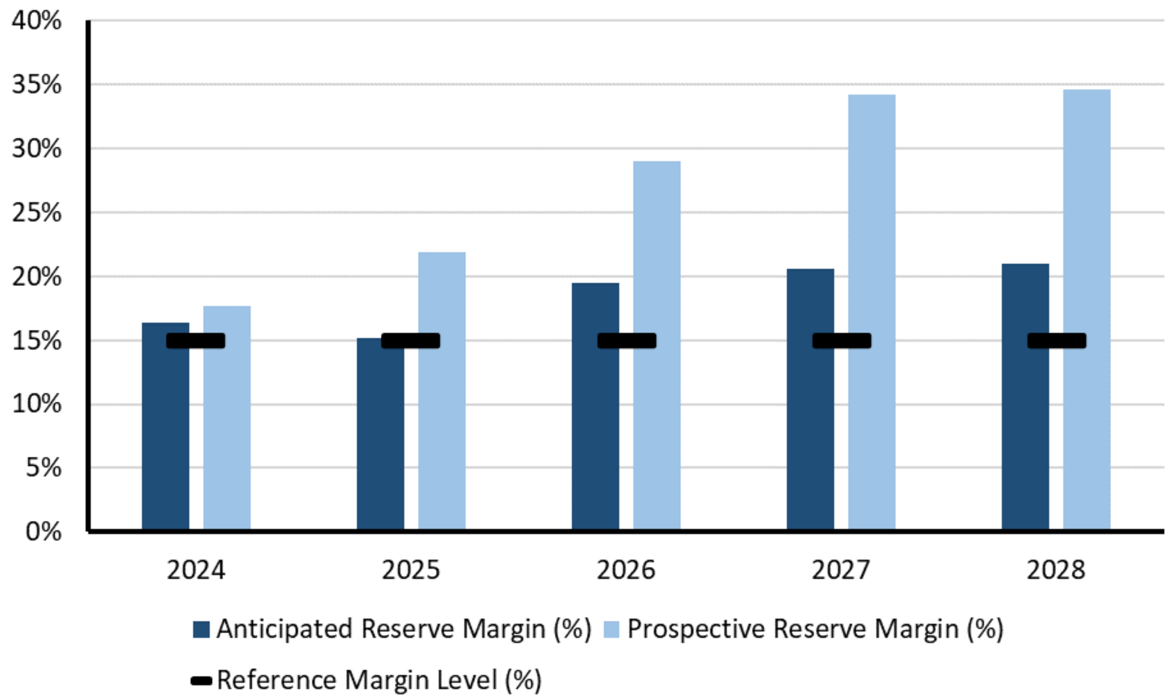


Figure 8: NPCC New York Five-Year Planning Reserve Margin

NYISO reliability studies identified a reliability need that would start in 2025 in New York City, resulting in NYISO evaluating proposed solutions. The need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City that is affected by a state law to reduce nitrogen oxide emissions. The deficiency will be significantly greater if a heatwave occurs.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation. Reliability margins are shrinking as generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher than expected demand, and extreme weather could threaten reliability and resilience in the future.

NPCC Ontario

Since the *2022 LTRA,* planned and contracted resource additions have improved the province's resource adequacy outlook. The ARMs in NPCC-Ontario are projected to remain above Ontario's current RMLs throughout the first five years of this assessment period (see **Figure 9**). The improved outlook is the result of 1,600 MW of upgrades and on-site expansions to natural-gas-fired generators and new BESS projects. In addition, a recent memorandum of understanding with neighboring province Québec adds 600 MW of firm summer capacity beginning in 2025. NPCC-Ontario meets resource adequacy criteria but with as little as 300 MW of surplus summer capacity in 2028 and later. Extreme conditions that cause peak demand to exceed forecasts or that cause above normal outages to occur could expose the area to risks of capacity shortfall. However, the risks can be mitigated with additional capacity from IESO's future annual capacity auctions and ongoing procurements.

[26] NERC uses a RML of 15% in the *2023 LTRA* Capacity and Energy Risk Assessment for NPCC New York in absence of an established Planning Reserve Margin requirement. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. 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 2023–2024 IRM at 20%. All values in the IRM calculation are based upon full Installed Capacity MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year. Additionally, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 event-days/year.

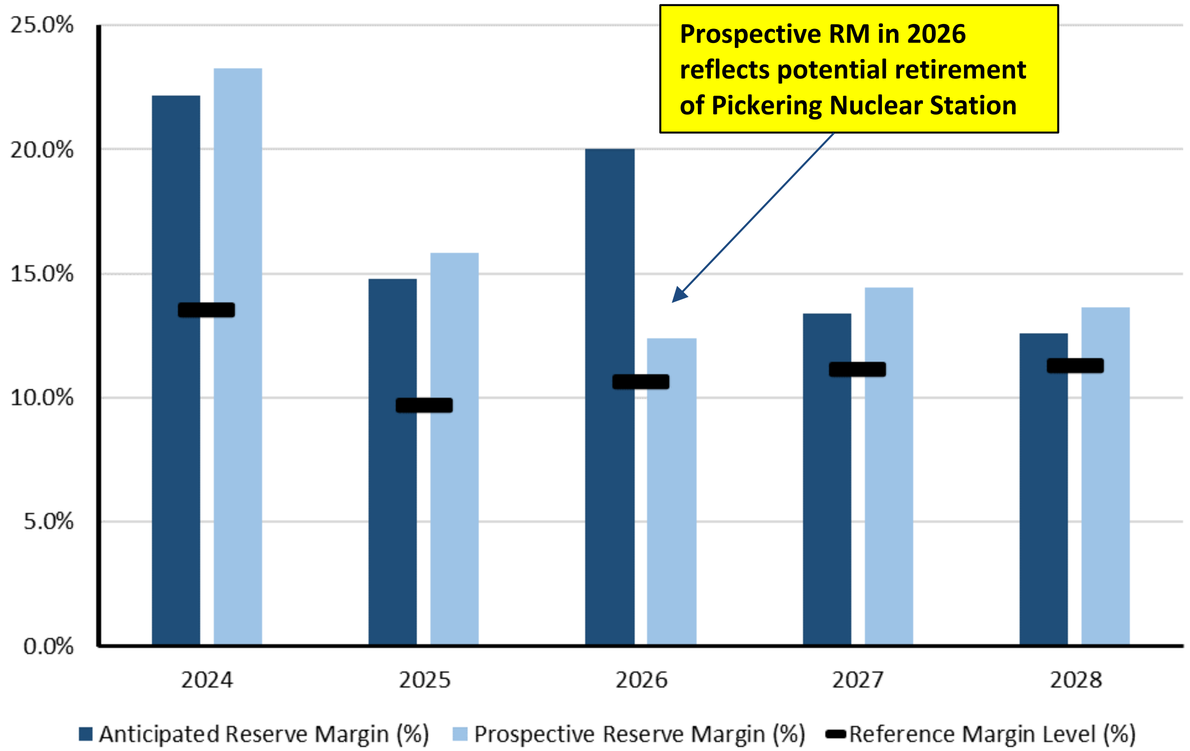


Figure 9: NPCC-Ontario Five-Year Planning Reserve Margin

As reported in the two prior *LTRAs*, the main drivers for Ontario's projected decline in capacity are planned retirements and lengthy outages for nuclear units undergoing refurbishment. In September 2022, Ontario's Ministry of Energy announced that it was supporting a plan by Ontario Power Generation to extend operation of Pickering Nuclear Generating Station beyond its planned retirement in 2025 through September 2026.

Recently, the Canadian federal government released a draft of clean electricity regulations; IESO is undertaking analysis to help inform the final draft.

SPP

Since the *2022 LTRA*, SPP's projected reserve margins for this assessment period have declined while the RMLs needed for maintaining reliability have risen. Consequently, SPP's surplus capacity over the next five years has fallen sharply. See **Figure 10**.

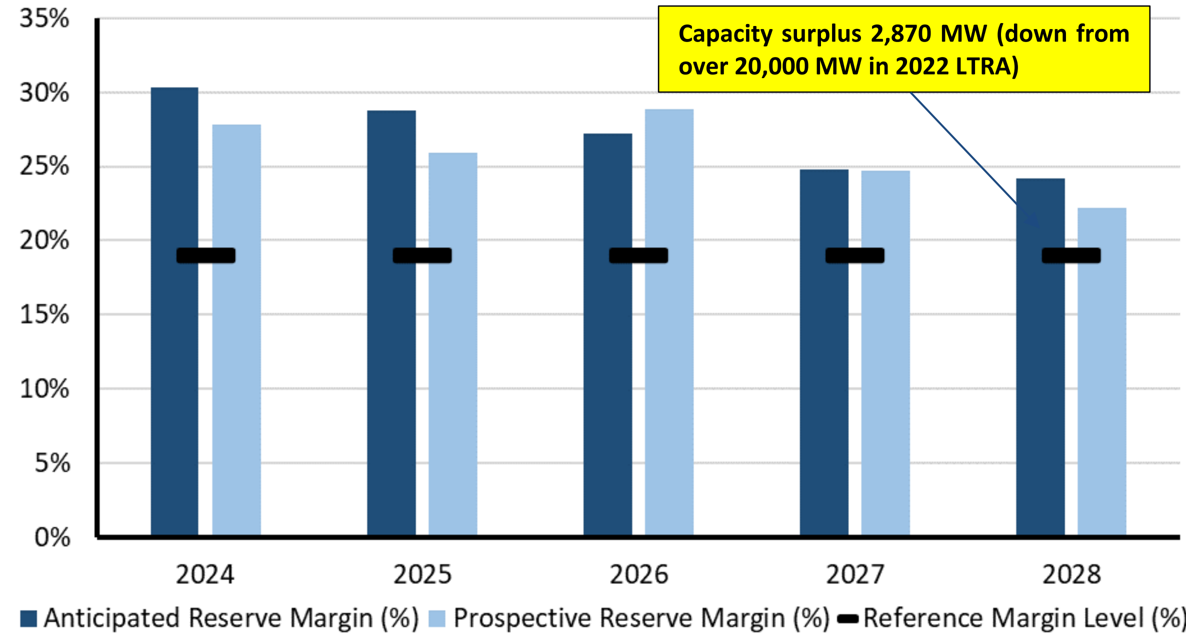


Figure 10: SPP Five-Year Planning Reserve Margin

Lower reserve margins are driven by generation retirements (1,500 MW since the *2022 LTRA*) and rising peak demand forecasts. Winter forecasted peak demand growth is outpacing summer (winter CAGR 1.24% vs. summer CAGR 1.12%). SPP raised the RML from 16% to 19% beginning in 2023 based on its most recent biennial LOLE study. The previous RML was not sufficient to meet 0.1 day/year LOLE. LSEs in SPP must procure resources to cover a higher RML.

SPP's sizeable but diminishing reserve margins do not account for planned, forced, or maintenance generator outages. Instead, they reflect the full availability of accredited capacity. Additionally, anticipated resources do not reflect derates based on real-time operational impacts. Capacity and energy shortfalls can occur in SPP when high demand coincides with low-wind or above-normal generator outages.

Texas RE-ERCOT

Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. Rising demand forecasts adds to energy risks as the risk of shortfalls increases during warm season evening hours when demand remains high while solar output is diminished. Sufficient levels of dispatchable generation and demand-side resources are needed. New and proposed EPA rules heighten the risk of thermal unit retirements before solutions are in place for reliability (e.g., transmission, resource adequacy).

Extreme winter weather (e.g., Winter Storm Uri in February 2021) remains a serious concern, warranting continued efforts ensure adequate resources are available and capable of performing in severe conditions to meet extreme demand. Market reforms and reliability initiatives that have been instituted are expected to reduce risks in extreme weather. These include the performance credit mechanism (PCM) incentives to generators for commitments to produce during tight grid conditions and to the firm fuel supply service (FFSS), which provides resources that are supported by on-site fuel or have off-site natural gas storage that meets qualification criteria.

U.S. Western Interconnection (WECC-CA/MX, WECC-NW, WECC-SW)

Throughout the U.S. assessment areas in WECC, both demand and resource variability are projected to continue as the resource mix transitions and DERs grow. In normal conditions, the expected demand and resource variability is balanced across the area as excess supply from one part of the system is delivered through the transmission network to places where demand is higher than supply. However, more extreme summer temperatures that stress large portions of the Interconnection reduce the availability of excess supply for transfer while also reducing the transmission network's ability to transfer the excess.

Energy Risks in WECC-CA/MX

Resource additions, generator uprating, and service extensions in WECC-CA/MX have helped alleviate near-term capacity risks and lower the area's reliance on imports to meet high demand. ARMs continue to rise from levels reported in NERC's previous LTRAs as new resources (primarily solar PV), hybrid-solar PV, and BESS are added (see **Figure 11**). Anticipated resources are sufficient to meet forecasted peak demand throughout this assessment period.

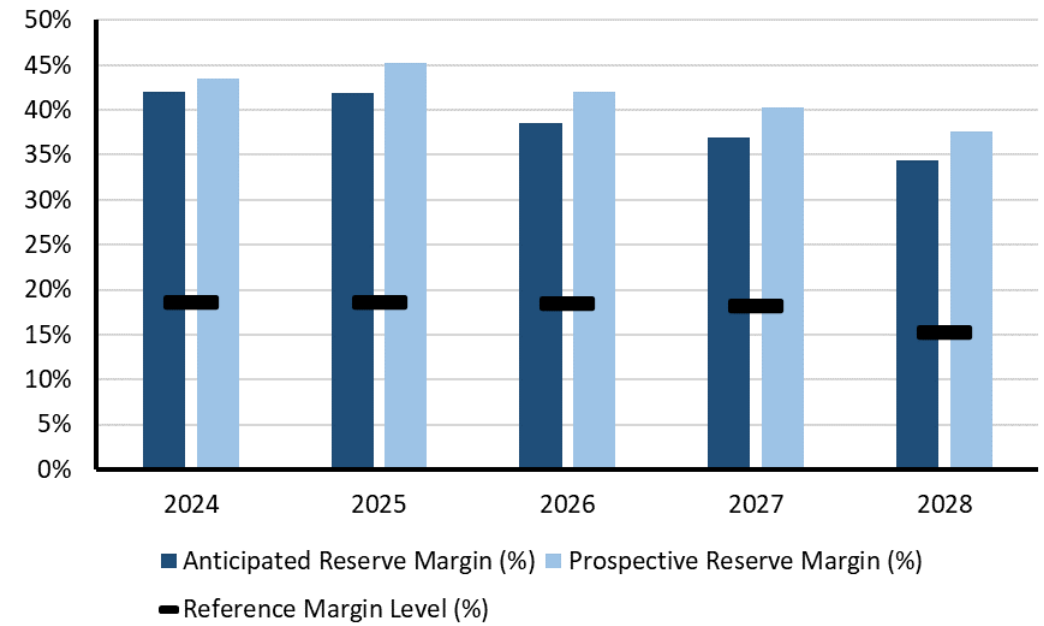


Figure 11: WECC-CA/MX Five-Year Planning Reserve Margin

Despite the on-peak capacity surplus, energy risks persist and are projected to increase after 2024 as additional thermal generators are planned for retirement. **Table 1** provides the results of probabilistic analysis performed by WECC that identify the risks of unserved energy and load-loss. Comparing the results of WECC's probabilistic analysis performed in 2022 with the current results indicates that risks of unserved energy and load loss in 2024 have fallen to negligible levels. However, loss-of-load and unserved energy risks emerge in the July–September period of 2026 and are primarily associated with extreme weather conditions.

Table 1: CA/MX ProbA Base Case Summary of Results

	2024*	2024	2026
EUE (MWh)	37,305	-	11,731
EUE (PPM)	136	-	43
LOLH (hours per Year)	0.721	-	0.227
Operable On-Peak Margin	30.3%	30.7%	27.5%

** Results from the 2022 ProbA are provided for comparison and are trending with the current results.*

WECC-CA/MX remains dependent on electricity imports to manage periods of extreme electricity demand or low resource output. Energy shortfall risks are associated with periods of above-normal demand that coincide with lower-than-normal resource output that is most pronounced during summer late-afternoon and evening periods when solar PV output is lower (see Figure 12). Heat events that span a wide area and reduce the availability of electricity imports into California are likely to continue to raise concerns and increase the risk of energy shortfalls.

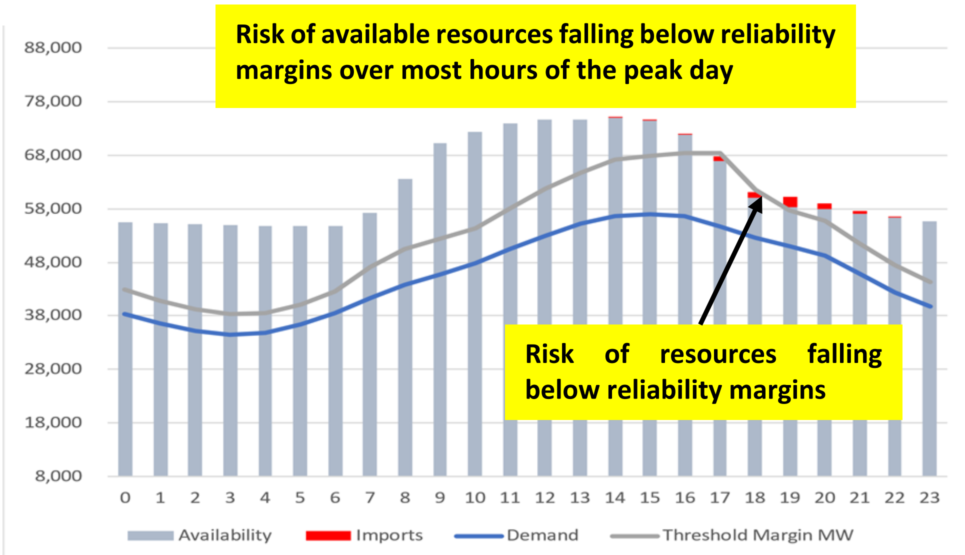


Figure 12: Hourly Resources and Demand Modeled for 2026 Summer Peak Day in WECC-CA/MX (Source: WECC)

Energy Risks in WECC-BC

Forecasted peak demand growth is causing a decline in reserve margins and reduced surplus capacity for managing periods of above-normal demand. British Columbia (WECC-BC) is a winter-peaking area that experiences peak demand typically in the early evening (6:00 p.m.) hours of December. Peak demand is forecasted to grow from 11.6 GW in 2023 to 12.9 GW in 2033. Anticipated resources are sufficient to meet forecasted peak demand throughout this assessment period. See Figure 13.

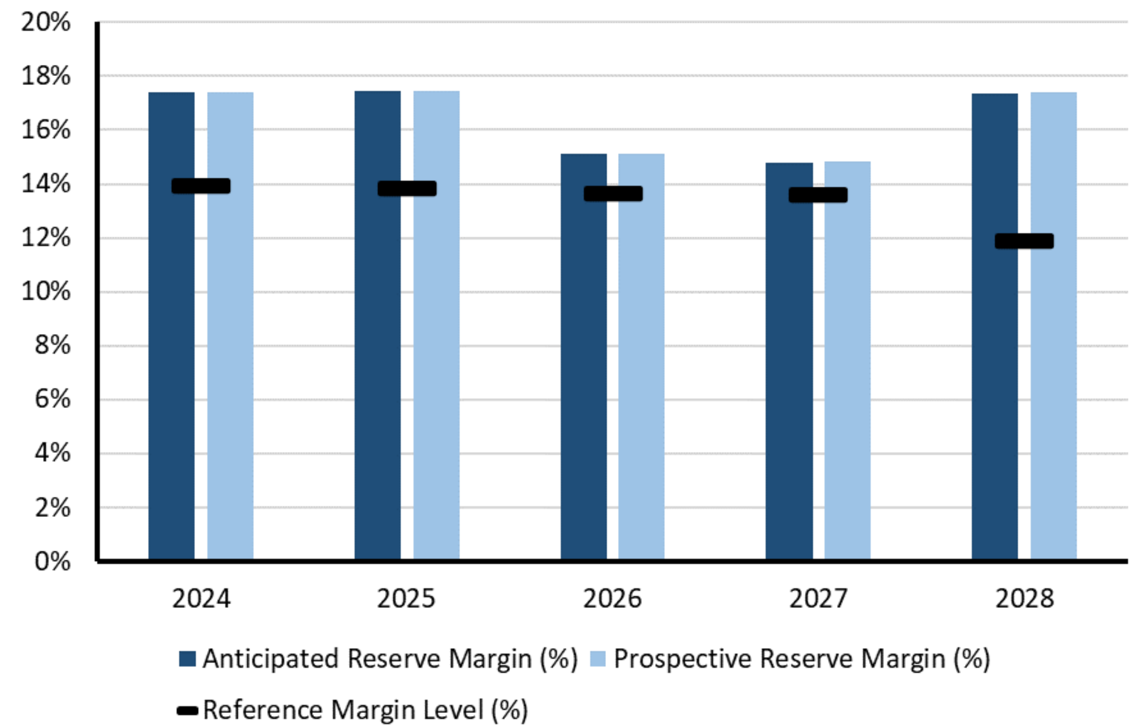


Figure 13: WECC-BC Five-Year Planning Reserve Margin

Energy shortfall risks in the WECC-BC assessment area are associated with extreme weather conditions that cause periods of above-normal demand to coincide with lower-than-normal resource output. Figure 14 shows WECC's modeling of electricity supply and demand for the representative peak day in December 2026. ProbA results show little energy risk in 2024. However, load-loss and unserved energy risks increase in 2026 as forecasted demand increases and natural-gas-fired generation retires.

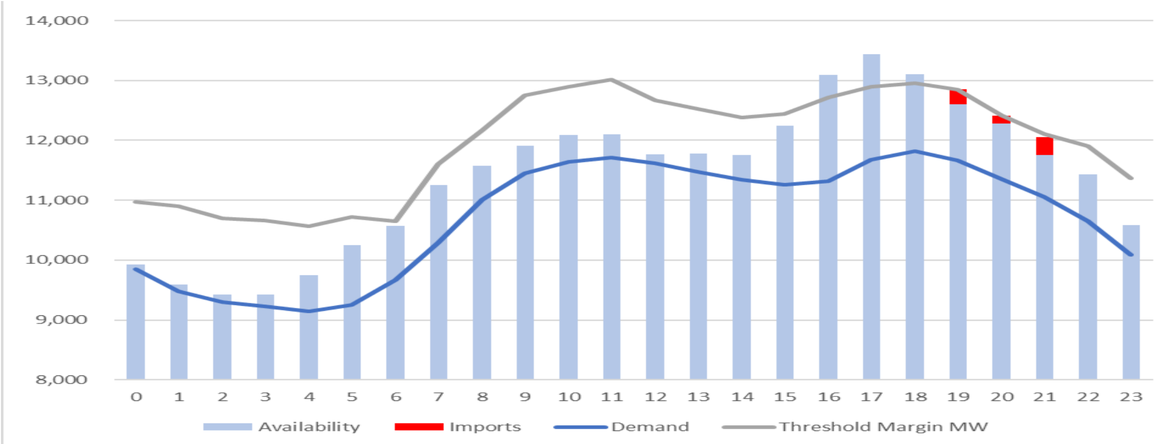


Figure 14: WECC-BC Hourly Resources and Demand Modeled 2026 Winter Peak Day (Source: WECC)

Energy Risks in WECC-NW and WECC-SW

Like WECC-CA/MX, the U.S. Northwest (WECC-NW) and U.S. Southwest (WECC-SW) are projected to be at risk of resource shortfalls during extreme summer weather conditions after 2024. Although the assessment areas are projected to have sufficient capacity to meet forecasted peak demand throughout this assessment period, dispatchable generation declines as generators retire in 2026 and later. The resulting resource mix is more variable, causing a risk of supply shortfalls during extreme summer conditions in WECC's probabilistic analysis (see **Table 2** and **Table 3**).

Table 2: WECC-NW ProbA Base Case Summary of Results

	2024*	2024	2026
EUE (MWh)	1,722	-	8,101
EUE (PPM)	4	-	21
LOLH (hours per Year)	0.036	-	0.132
Operable On-Peak Margin	25.8%	37.6%	32.5%

**Results from the 2022 ProbA are provided for comparison and trending with current results*

Table 3: WECC-SW ProbA Base Case Summary of Results

	2024*	2024	2026
EUE (MWh)	84	-	818
EUE (PPM)	1	-	6
LOLH (hours per Year)	0.003	-	0.031
Operable On-Peak Margin	28.1%	18.3%	18.4%

**Results from the 2022 ProbA are provided for comparison and trending with current results*

WECC-NW and WECC-SW areas' loss-of-load and unserved energy risks are associated with extreme weather events and concentrated in the late afternoon and early evening hours during the July–September period. See the **Regional Assessments Dashboards** pages for WECC's modeling of electricity supply and demand for the peak days in these areas. Modeling shows that imported electricity supplies are needed in all U.S. Western Interconnection assessment areas to meet forecasted demand during summer peak demand days, raising concerns of supplies during a wide-area heat event.

Normal Risk Area Details

All other assessment areas (see **Figure 1**) are assessed as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). See **Normal Risk Areas** for additional information.

Resource and Demand Projections

The **Capacity and Energy Risk Assessment** section in this *LTRA* is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these areas. The future electricity supply will come from a resource mix that is more variable, weather dependent, and reliant on natural gas for fuel without a broad coordination and careful attention to the pace of change. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to rise during this *2023 LTRA* assessment period at their highest rates in recent years, providing another sign of acceleration in the broader energy transition. In summary and taken all together, the energy transition has growing potential to threaten resource and energy adequacy without broad coordination and careful attention to the pace of change.

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the **Recommendations: Details** section of this report.

Resource Mix Changes

Findings: Wind, solar PV, and hybrid generation are projected to be the primary additions to the resource mix over this 10-year assessment period, leading the continued energy transition as older thermal generators retire. Maintaining a reliable BPS throughout the transition requires unwavering attention to ensure the resource mix satisfies capacity, energy, and ERS needs under designed conditions. It will also require significant planning and development of the interconnected transmission system to have a deliverable electricity supply from new resources to loads and the ability to withstand system contingencies and disturbances.

The addition of VERs (primarily wind and solar PV) 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. Maintaining reliability will require industry and regulators to carefully manage the pace of change and take steps to ensure that ERSs continue to be provided as generators retire.

Generation Resource Mix in 2023 vs. 2033

The total capacity of traditional baseload generation fuel types will continue to decline as older generators retire and are replaced with new generation that has different capacity characteristics. Figure 15 shows how the current (**black)** resource mix (on-peak capacity) compares to the projection of the future on-peak capacity in 2033 (gray**)** if expected retirements occur and all projected Tier 1 resources are added. With these assumptions, the change in resource mix is gradual. Over this 10-year assessment period, Thermal generation, which consists mainly of natural-gas-fired, coal-fired, nuclear plants, and hydroelectric power are projected to continue providing 85% or more of the BPS on-peak generation capacity. As discussed below, the pace of change in the resource mix is likely to be influenced by the addition of more wind, solar PV, battery resources, and the retirement of more fossil-fired generators.

On-peak resource capacity reflects the expected capacity that the resource type will provide at the hour of peak demand. Because the electrical output of wind and solar PV VERs depends on weather and light conditions, on-peak capacity contributions are less than nameplate installed capacity. Wind on-peak capacity contribution contributions range between a low of 10% of installed capacity to over 25% in some assessment areas. Solar PV on-peak contributions are 0% in most areas during winter when the peak occurs in low light. In summer, some areas, such as ERCOT and parts of the U.S. West, can expect the solar PV contribution to reach over 80% of installed capacity at peak demand hour. High expected capacity contributions from VERs help increase Planning Reserve Margins but also increase the exposure of the system to energy risks from weather or environmental conditions that impact VER output. Supplementary tables on NERC's Reliability Assessments[27] web page provide on-peak capacity contributions of existing wind and solar PV resources in each assessment area.

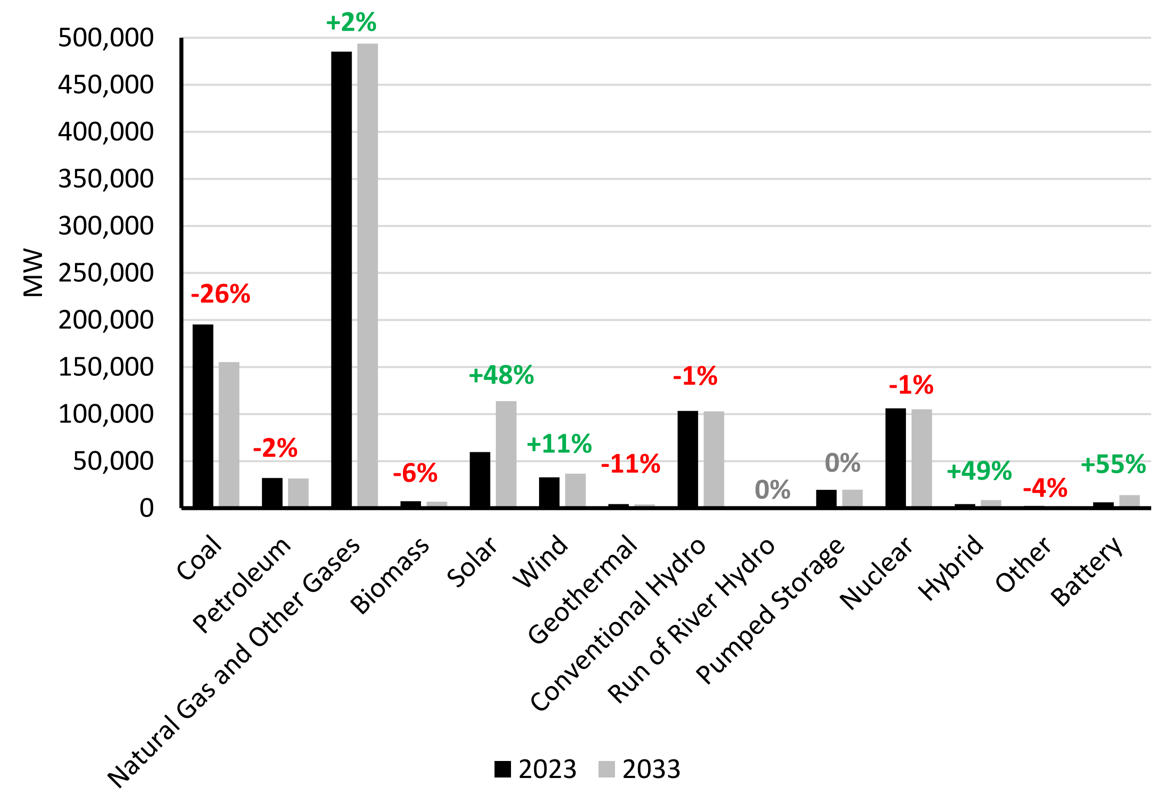


Figure 15: 2023 vs. 2033 BPS On-Peak Capacity by Fuel Type with Tier 1 Resources

[27] Reliability Assessments (nerc.com)

Capacity Additions

New generation is added to the BPS through the area interconnection planning processes. Wind, solar PV, and natural-gas-fired generation are the overwhelmingly predominant generation types planned for addition to the BPS. A summary of generation resources in the interconnection planning queues is shown in **Figure 16**. Capacity in planning has grown since the *2022 LTRA* by over 9 GW (2%).

In general, Tier 1 resources are in the final stages for connection while Tier 2 resources are further from completion. Supply chain issues, planning and siting challenges, and business or economic factors can cause projects to be delayed or withdrawn.

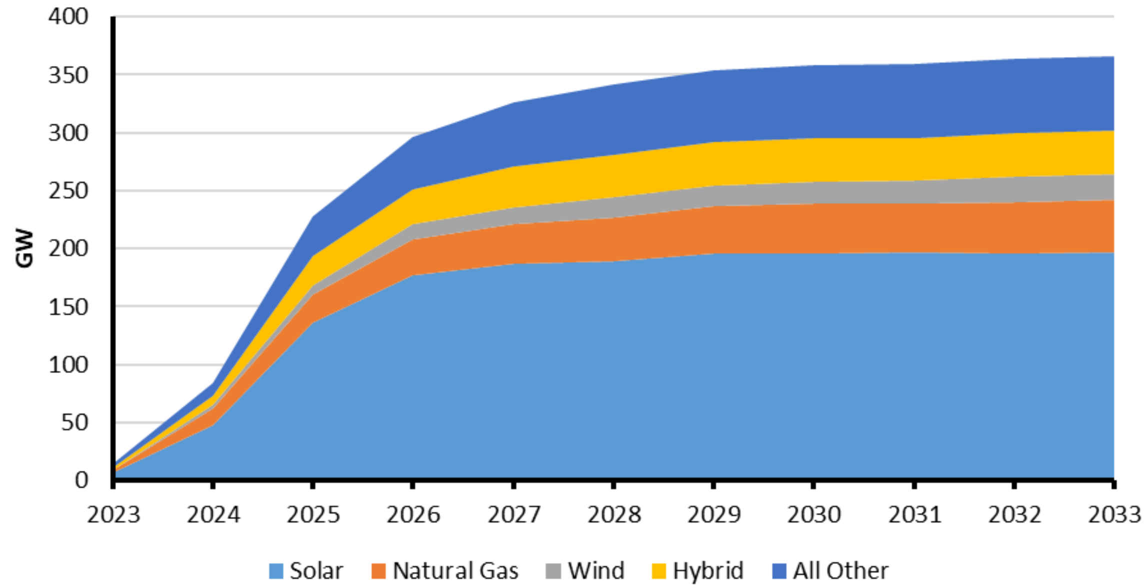


Figure 16: Tier 1 and 2 Planned Resources Projected Through 2033

Solar PV and wind capacity, both existing and planned, vary widely by area. **Figure 17** and **Figure 18** show current solar PV and wind installed capacities and the capacity in the planning process through 2033 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (i.e., a wind or solar farm), are connecting to the grid in parts of North America, and many more projects are in BPS planning processes.

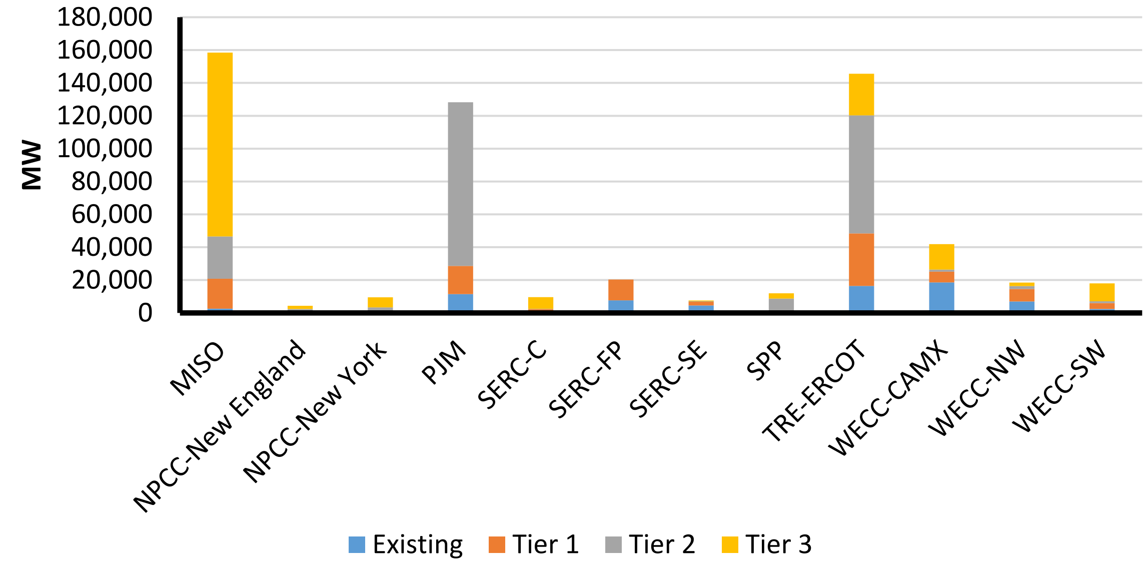


Figure 17: Solar Capacity Existing and Planned through 2033

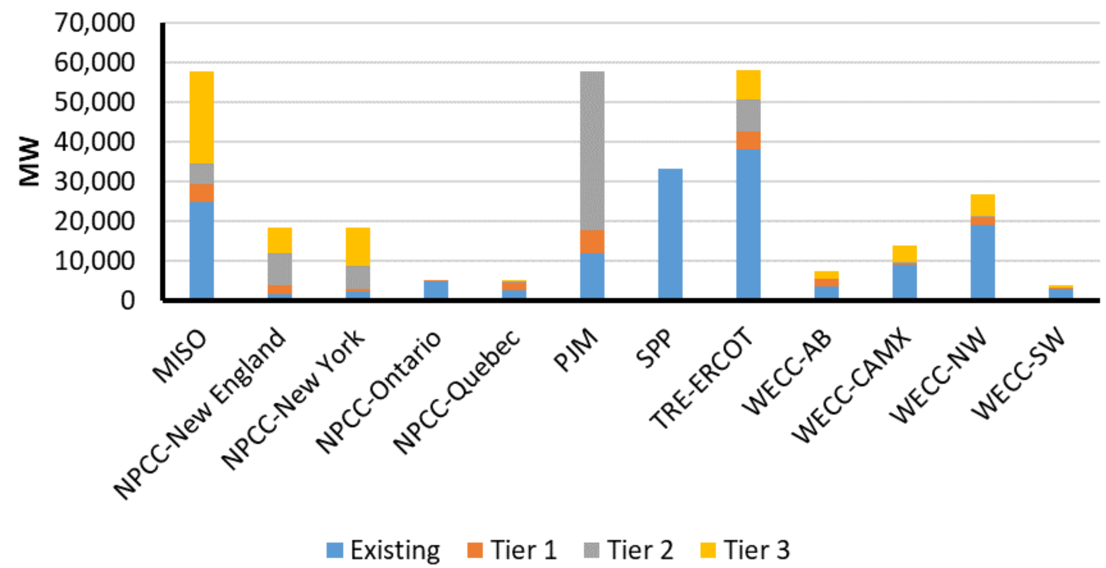


Figure 18: Wind Capacity Existing and Planned through 2033

Battery Resources

As the BPS increases the share of energy provided by VERs, the ability to provide energy by battery energy storage systems (BESS) or hybrid-solar PV and wind plants is increasingly important. While currently installed capacity totals 7,172 MW, over 260,000 MW of BESS are in planning. **Figure 19** shows the nameplate capacity of BESS resources currently in operation and in planning for connection to the BPS through 2033.

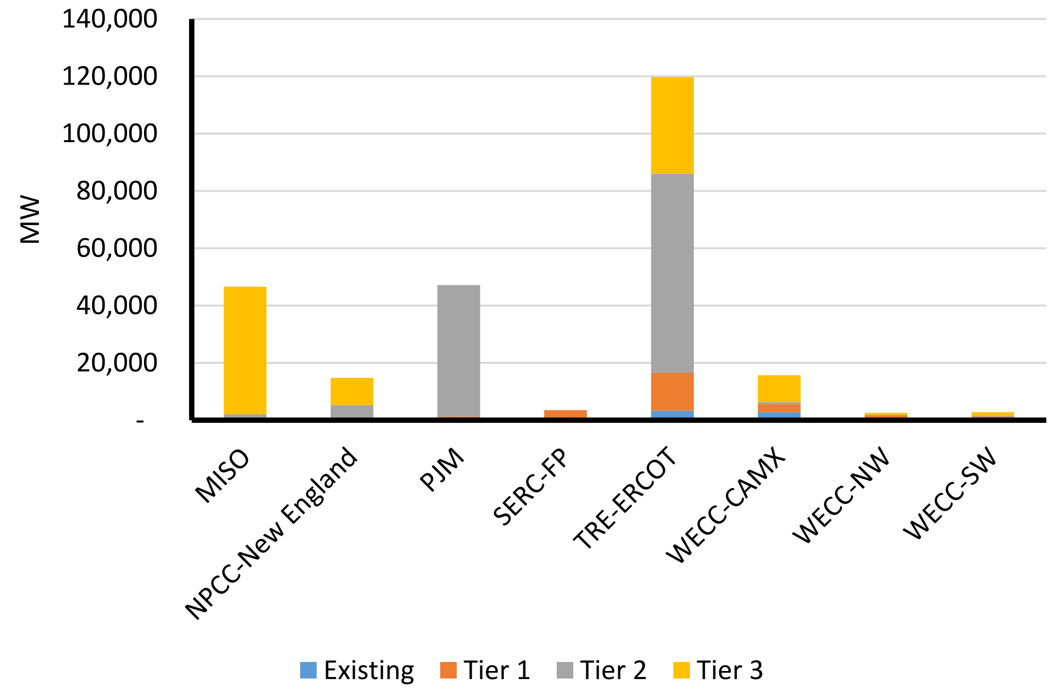


Figure 19: Battery Resource Capacity Existing and Planned through 2033

BESS have the potential to offer reliability benefits for the grid, such as helping to offset the variability and uncertainty of IBRs. BESS are, however, a relatively new type of grid resource with unique operating characteristics. The joint *NERC-WECC Staff Report:* 2022 California Battery Energy Storage System Disturbances[28] report highlights an event when a BESS, like some other IBRs, failed to properly ride through a normal system fault. This indicates that BESS must be included in the currently underway strategies to address IBR performance issues.

Planners and operators are focused on requirements to model, study, and operate the BPS with increased BESS and hybrid resources. In ERCOT and many other areas, BESS are used primarily for ancillary services, such as frequency response. In parts of the Western Interconnection with high solar PV penetration, BESS often reduce ramping requirements on other resources by discharging in late afternoon as solar PV output rapidly declines. The majority of currently installed BESS does not count towards peak hour contribution (i.e., they are not expected to discharge at peak demand). Wholesale markets, programs, and procedures are evolving to effectively integrate these new resources and realize their reliability benefits.

Solar PV Distributed Energy Resource Growth

Behind-the-meter (BTM) solar PV generators are solar PV resources connected on the distribution system, such as residential rooftop solar systems. The rapid growth of BTM solar PV continues with cumulative levels expected to reach almost 89 GW by the end of this 10-year assessment period (up from 80 GW reported in the *2022 LTRA*, an increase of 11.3%), see **Figure 20**.

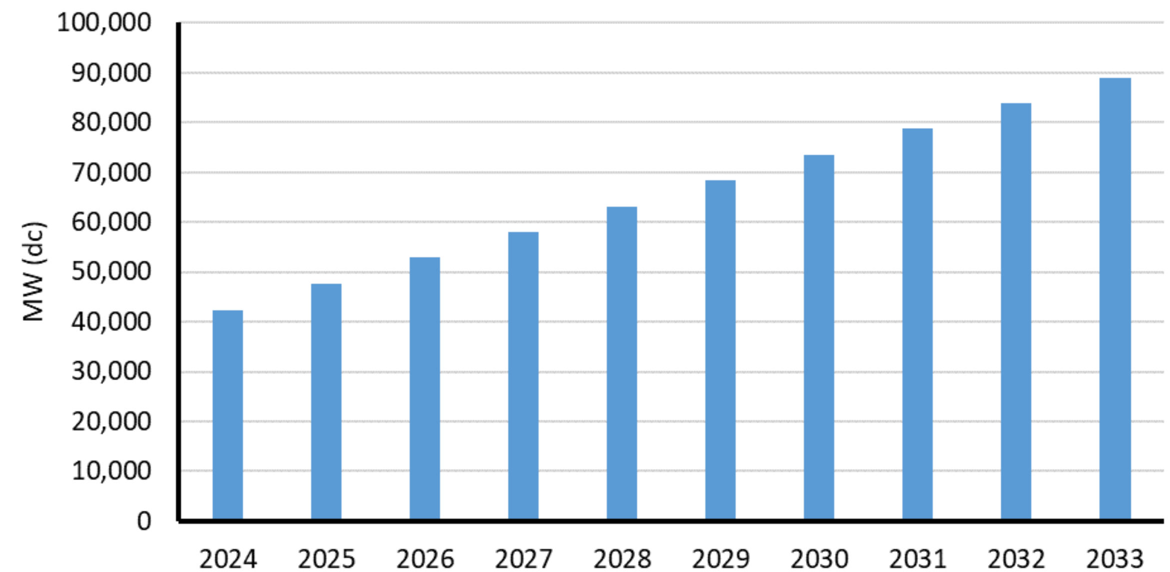


Figure 20: Cumulative Solar PV DER Capacity in All Assessment Areas

[28] NERC–WECC *2022 California Battery Energy Storage System Disturbances*

BTM solar PV generators, like grid-connected solar PV, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the Sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours; it may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. Figure 21 shows the current and projected BTM solar PV by area through 2033.

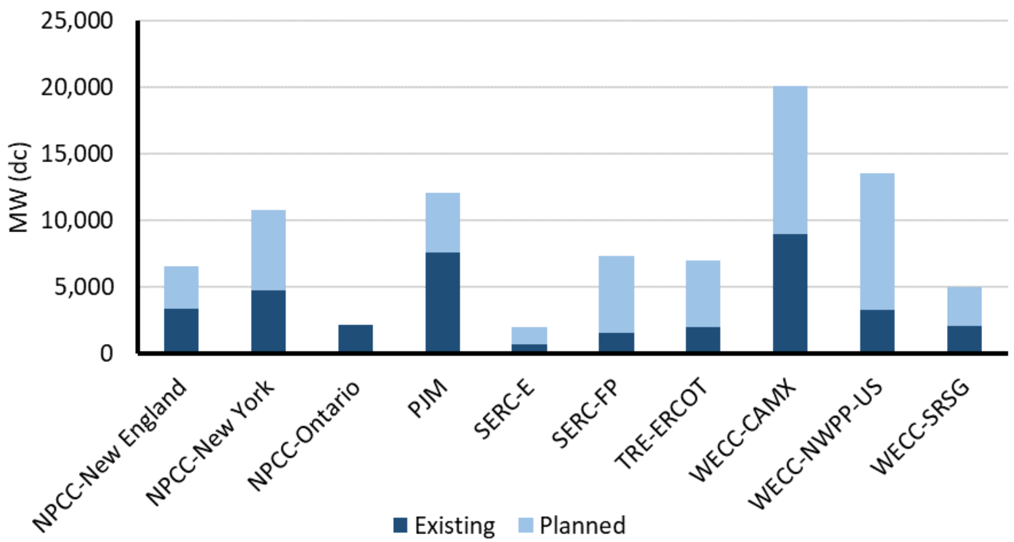


Figure 21: Solar PV DER Capacity Existing and Planned through 2033

Generation Retirements

The total capacity of traditional baseload generation fuel-types will continue to decline as older generators retire. Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or the integrated resource planning process in vertically integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Currently, over 83 GW of fossil-fired and nuclear generating capacity is retiring over this assessment period (see Figure 22). This capacity includes generators that are confirmed for retirement through retirement planning processes or that have indicated plans to retire to an ISO/RTO or planning coordinator.

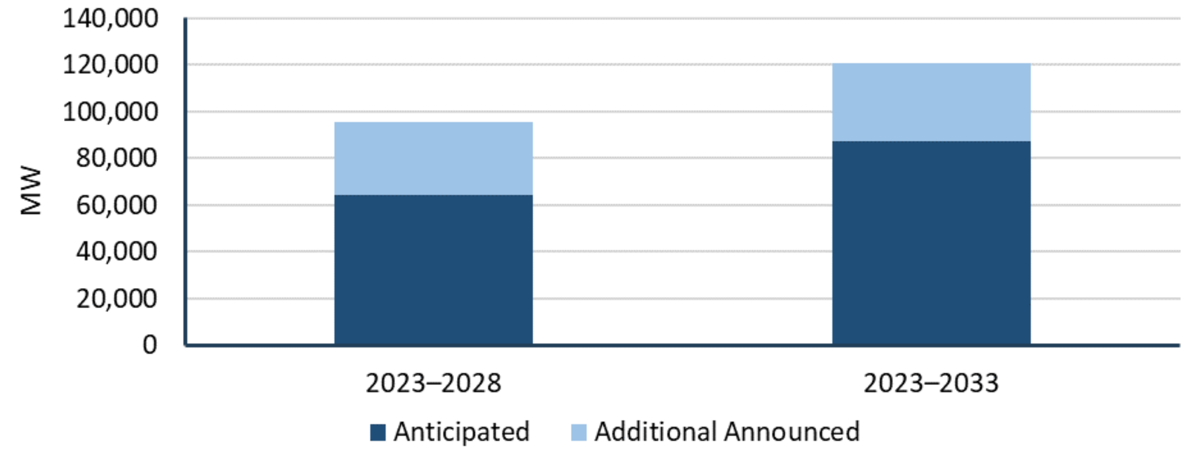


Figure 22: Projected Generation Retirement Capacity Through 2033

Additional fossil-fired generator retirements are expected, leading to a loss of existing capacity more than the reported 83 GW capacity. Generator Owners often announce plans to retire generator units before initiating the interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. Figure 23 shows the total capacity of reported retirements (i.e., reported to ISOs/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[29]

[29] Confirmed generator retirements are reported to NERC by each assessment area in this *2023 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

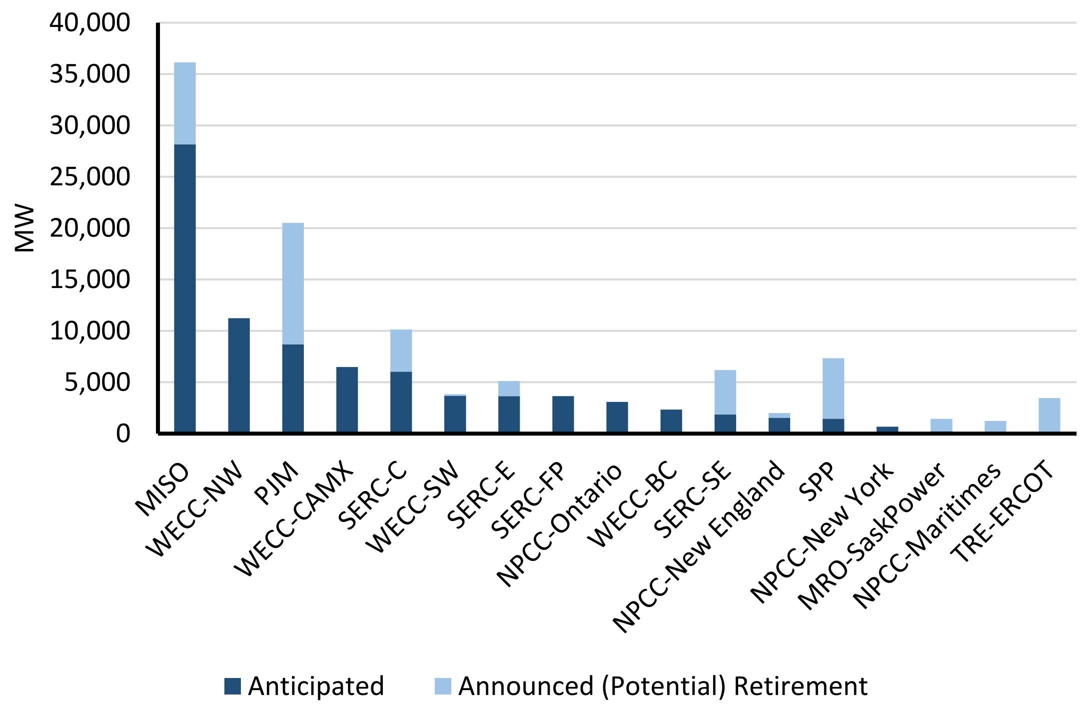
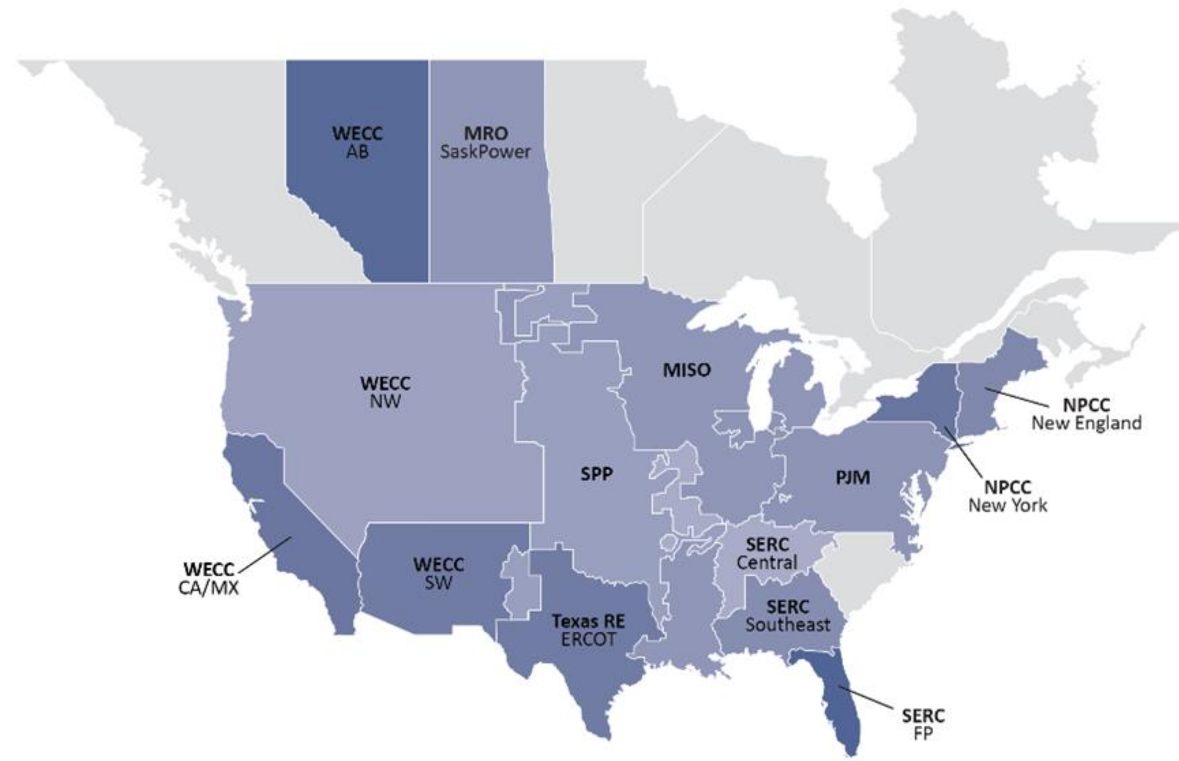


Figure 23: Projected Retiring Nuclear and Fossil Generation Capacity 2023–2033

Throughout this *2023 LTRA*, anticipated generation retirements have been removed from each assessment area's anticipated and prospective resources while unconfirmed, announced generator retirements have been removed from prospective resources only. See Page 32 for information about new policy and regulations that affect future generator retirements.

Natural Gas Fuel Reliance Trends

Natural-gas-fired generators are and will remain a critical resource for BPS reliability in many areas over the 10-year assessment period, especially during winter. Figure 24 shows the total contribution of natural gas to the winter resource mix; in the figure, areas with more natural gas are darker blue. See Table 4 for the specific values for each area. These generators provide many necessary reliability attributes that are exiting the system as traditional generators retire and inverter-based renewable resources take their place in the resource mix. Natural-gas-fired generators are dispatchable and provide the ERSs of inertia, frequency response, and ramping flexibility. In winter, when peak demand in most areas occurs during early morning hours, natural-gas-fired generation is at its highest contribution to the resource mix in many areas. Severe winter weather events in 2021 and 2022 provided stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure supplies during times of extreme electricity demand. While more work remains, several important steps to mitigate the risks of natural gas supply interruption have been taken in the aftermath of Winter Storm Uri in February 2021.



All other assessment areas have less than 35% natural gas fired generation contribution to winter resource mix.

Figure 24: Natural-Gas-Fired Generation Contributions to 2023–2024 Winter Generation Mix

For example, ERCOT has developed an FFSS whereby capacity with qualifying on-site fuel or off-site natural and other gas storage can be procured by LSEs through a competitive procurement process with a single clearing price. ERCOT is also working to implement a newly adopted Public Utility Commission of Texas PCM rule that permits generation resources within ERCOT to commit to producing more energy during the tightest grid conditions of the year and sell credits to LSEs. Convened in response to Winter Storm Uri report, the North American Energy Standards Board Gas Electric Harmonization Forum has completed its work and published 20 recommendations that are directed at harmonizing across and improving coordination between natural gas supply/transport and BES operations.

Table 4: Total Natural Gas Peak Winter Capacity		
Assessment Area	Total in GW	Contribution to Total Winter Resource Mix
MISO	67.5	46%
MRO-SaskPower	2.1	46%
NPCC-New England	17.3	54%
NPCC-New York	24.5	66%
PJM	84.9	47%
SERC-Central	22.7	44%
SERC-Florida Peninsula	50.6	79%
SERC-Southeast	31.5	51%
SPP	27.4	41%
Texas RE-ERCOT	54.2	62%
WECC-AB	11.4	75%
WECC-CA/MX	39.9	65%
WECC-NW	31.0	39%
WECC-SW	18.2	62%

Supply Chain Concerns

New resource additions are critical to maintaining resource adequacy criteria and reducing energy shortfall risk under more extreme conditions. Supply chain issues have impacted resource projects over the past year. Lingering pandemic-related issues, competition for scarce resources, and geopolitical matters are likely to continue affecting generation and transmission projects. Supply chain issues are also making the following more difficult: the scheduling of maintenance outages, planning for when new resources will come online when line upgrades can be completed, and the ability to connect new customers. Grid planners and system operators need to continue accounting for uncertainties in resource availability.

Reliability Implications

The addition of variable resources, primarily wind and solar PV, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. Geographically diverse wind and solar resources and loads can help reduce these risks, but they require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms. Specific and actionable recommendations are contained in the **Recommendations: Details** section of this report.

New Policy and Regulations Affecting Future Generator Retirements

Coal-fired generating capacity has declined significantly over the past decade, falling from over 280 GW in 2014 to the current level of 195 GW.[30] The U.S. Energy Information Administration models project this trend to steadily continue over the next decade and beyond (**Figure A**).[31] Furthermore, many of these modeled projections exceed the announced generator retirements as shown in **Figure 22**, heightening concerns that generation is at risk of retirement before reliability solutions are in place.

Future fossil-fired generator retirements will be influenced by a range of factors, such as environmental policies, incentives for new renewable generation, operating economics, and technology developments. The Inflation Reduction Act contains climate and energy provisions, including tax credits and expenditures that will influence the BPS resource mix by supporting renewable resources, energy storage, and nuclear generation. The Inflation Reduction Act will accelerate the energy resource transformation, including additional fossil-fired generator retirements. While subject to change in the rulemaking process, proposed EPA regulations under Clean Air Act Section 111 to address carbon emissions from fossil-fired generators would result in an increase in the rate of generator retirements.[32] Recent analysis and models that incorporate the potential effects of these new policies and proposed regulations illustrate projections for coal-fired generator retirements in excess of currently announced retirements (**Figure B**).[33] Natural-gas-fired generator retirements are also expected to increase under proposed new EPA regulations as Generator Owners face added costs of emissions-reducing technologies. Technologies for enabling generators to operate to the new standards are also being developed.

Additional generator retirements beyond currently expected levels have the potential to exacerbate energy, capacity, or ERS issues. See the **Capacity and Energy Assessment** and **Reliability Implications** in the preceding sections of this *2023 LTRA*. Close coordination will be needed among regulators, policymakers, and industry to ensure that sufficient electricity resources will be available to meet rising demand and grid reliability needs. Regulations that have the potential to accelerate generator retirements or restrict operations must have sufficient flexibility and provisions to support grid reliability.

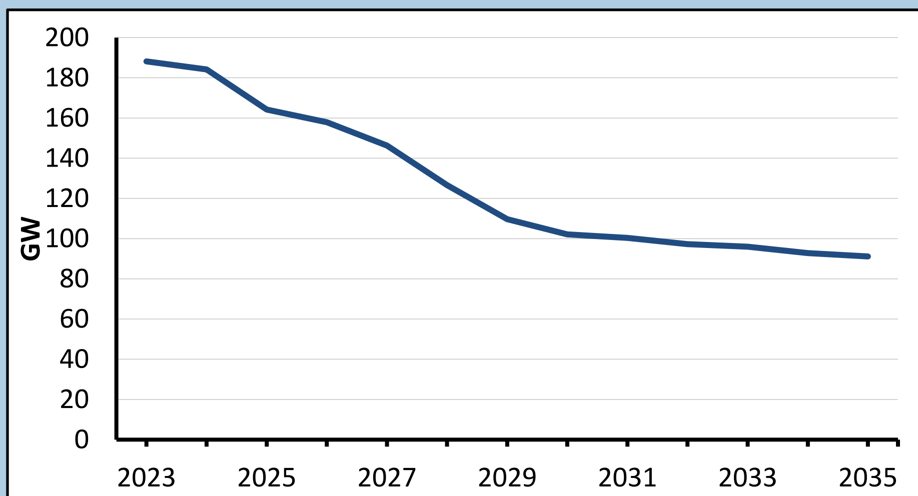


Figure A: BPS Coal-Fired Generation Capacity–United States Only

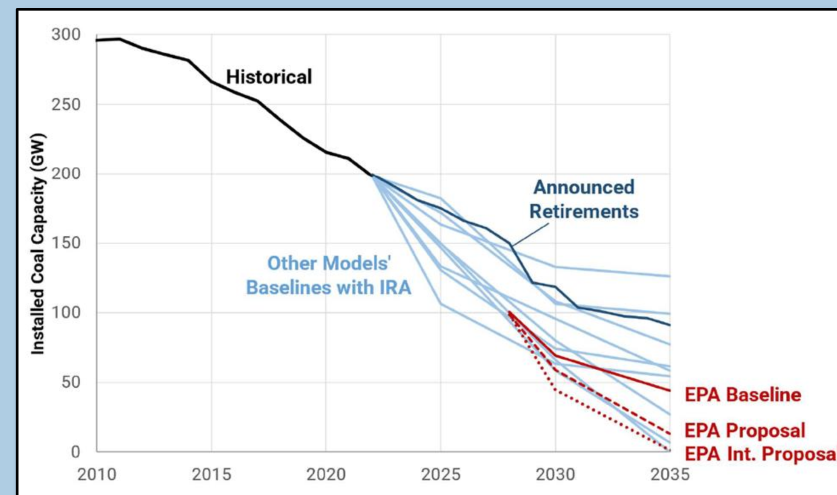


Figure B: BPS Coal-Fired Generation Capacity in Various Scenario Models–United States Only

[30] NERC 2014 LTRA
[31] EIA Annual Energy Outlook 2023
[32] EPA Rulemaking Docket New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of Affordable Clean Energy Rule
[33] *Source: Comment submitted by Electric Power Research Institute (EPRI), Docket EPA-HQ-OAR-2023-072, New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule:* EPRI Comments on U.S. EPA Rule, Docket ID EPA-HQ-OAR-2023-072

Demand Trends and Implications

Finding: Electricity peak demand and net energy growth rates in North America are increasing more rapidly than at any point in the past three decades. Concentrated growth and the emergence of new types of loads are occurring in some areas. These growth trends bring additional challenges for resource and transmission adequacy. Planners and operators can prepare by considering robust demand and energy scenarios, carefully monitoring and refining demand forecasts, and developing operational tools for peak load management.

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period are higher than at any point in the past decade. The aggregated assessment area summer peak demand forecast is expected to rise by over 79 GW, and aggregated winter peak demand forecasts are increasing by nearly 91 GW. Furthermore, the growth rates of forecasted peak demand and energy have risen sharply since the *2022 LTRA*, reversing a decades-long trend of falling or flat growth rates. See **Figure 25** for seasonal peak demand growth over the current and prior assessment periods and **Figure 26** for net energy growth. More information is available in the **Regional Assessments Dashboards** section.

Electrification and Demand Growth

Electrification and projections for EV growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2022 LTRA*, peak season CAGR has risen in all assessment areas except two: (WECC-AB winter CAGR fell slightly from 0.6% to 0.56% while ERCOT's summer CAGR was unchanged at 1.01%). Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

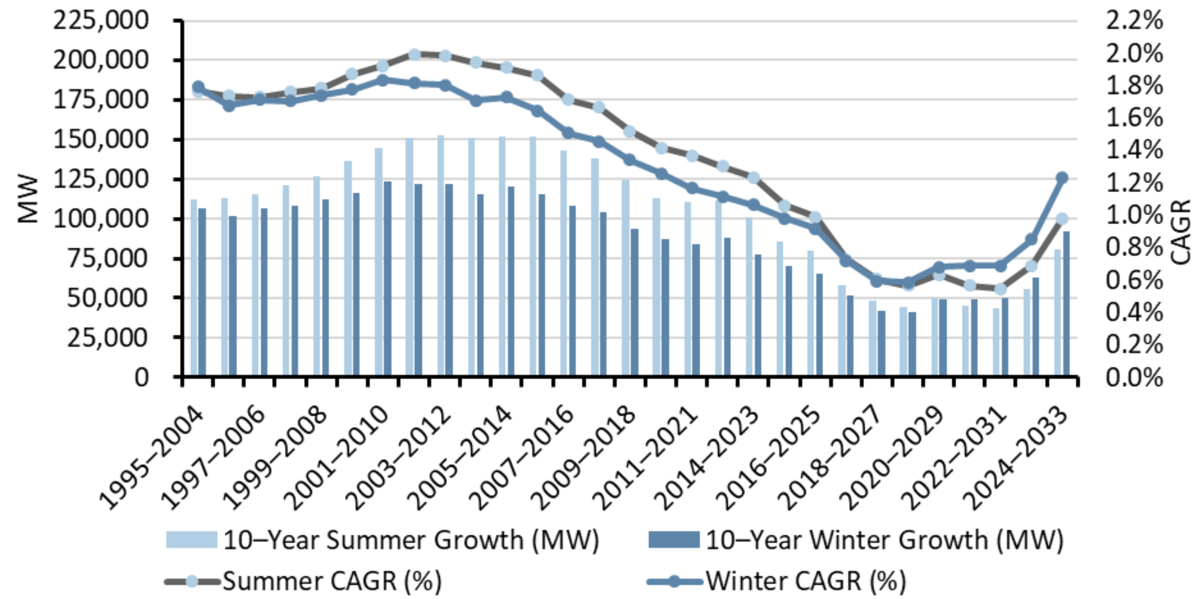


Figure 25: The 10-Year Summer and Winter Peak Demand Growth and Rate Trends

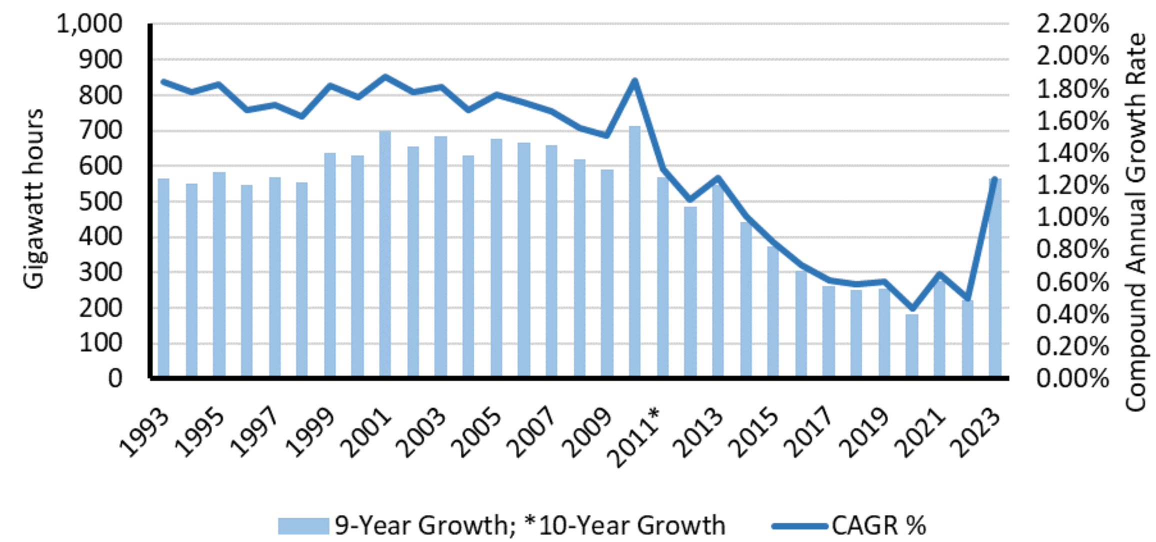


Figure 26: Net Energy for Load Growth and Rate Projection Trends

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of EVs (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output can be significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from a summer-peaking system to a winter-peaking (or dual-season peaking) system and the approximate year of the transition:

- NPCC-New England (mid 2030s)
- NPCC-New York (mid 2030s)
- NPCC-Ontario (2036)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer.

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and DER performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating electrification, EV adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year had noticeable effect on resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Transmission Development Trends and Implications

Finding: The amount of BPS transmission projects reported to NERC as under construction or in planning for construction over the next 10 years has increased, indicating an overall increase in transmission development. Siting and permitting challenges continue to inflict delays in transmission expansion planning. Regional transmission planning processes are adapting to manage energy transition, but impediments to transmission development remain.

Transmission Projects

This year's cumulative level of 18,675 miles of transmission (>100 kV) in construction or stages of development for the next 10 years (**Figure 27**) is higher than averages of the past five years of NERC's LTRA reporting on average (16,970 miles of transmission planning projects in each 10-year period published in the last five LTRAs).

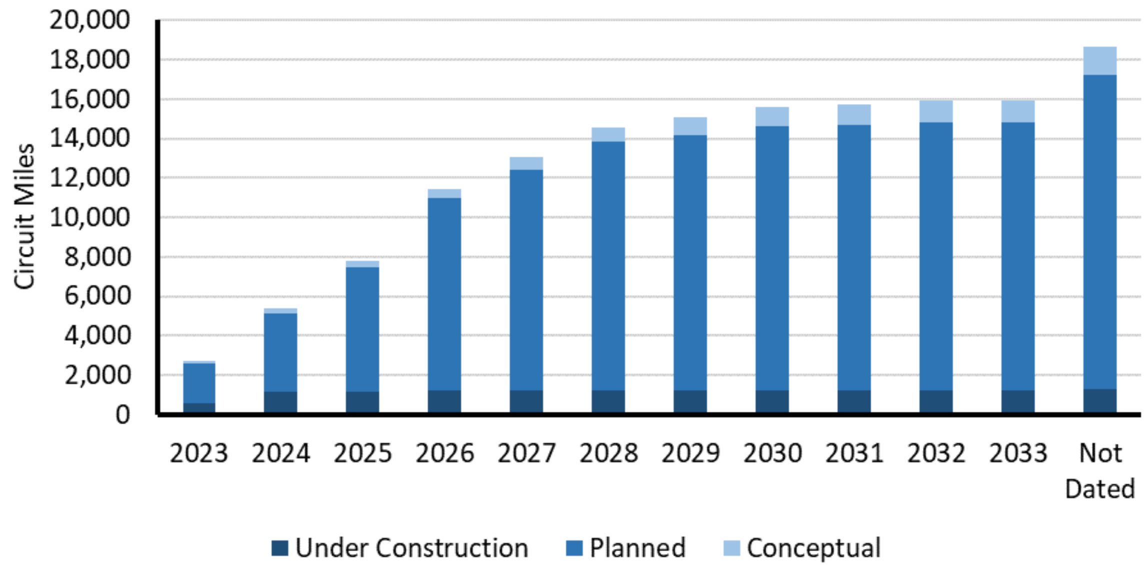


Figure 27: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 28** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria. Some substantial new projects to integrate renewable generation are also in development or are entering planning processes. The NPCC-New York and PJM assessment areas have begun transmission planning to support interconnection of offshore wind resources. See the transmission summaries at the end of each assessment area's pages (see **Regional Assessments Dashboards)** for current transmission development details.

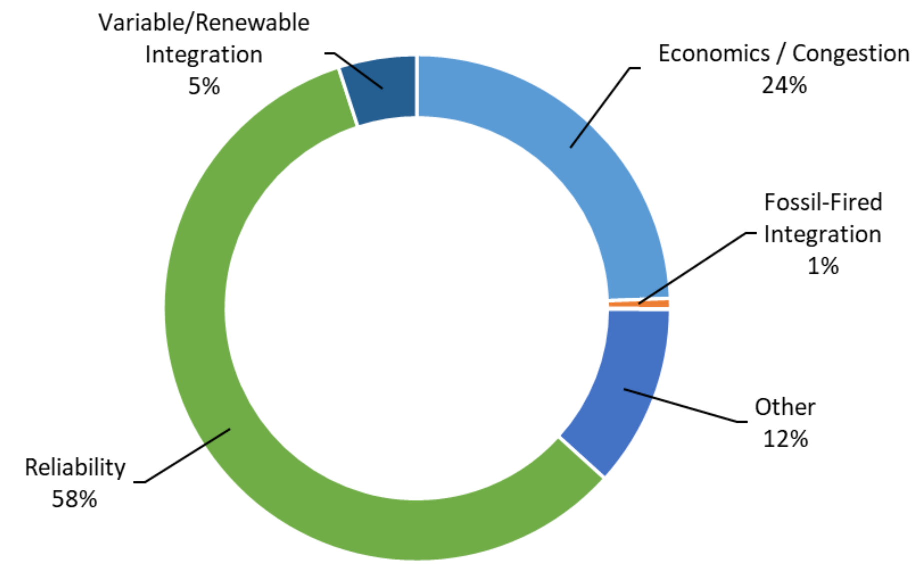


Figure 28: Future Transmission Circuit Miles by Primary Driver

Transmission development in some areas is hampered by siting and permitting challenges. Of the over 900 projects that are under construction or in planning for over the next 10 years, 87 projects are currently delayed from their expected in-service dates. Siting and permitting issues are the most common cause for delays (i.e., 46 projects for a total of 940 miles of new transmission). Other reasons for delays include economic or changing needs.

Adapting Transmission Planning Processes

Regional transmission planning and resource interconnection processes are adapting to manage the development needs of the energy transition. Across ISO/RTO organizations, long-term system planning is increasingly evaluating policy-driven projects that would support investment decisions necessary to reach state and province goals. Many are also instituting processing reforms that are aimed at reducing backlogs in generation interconnection queues. See the **Regional Assessments Dashboards** for details on changes and initiatives.

Reliability Implications

Monitoring and managing transmission planning processes is a necessary part of maintaining reliability as the resource mix evolves. Furthermore, the rapidly changing resource mix requires greater access and deliverability of resources, including transmission availability, to maintain reliability. Regional transmission planning processes are adapting to manage the energy transition, but impediments to transmission development remain.

The transmission system is being tested by an ever-evolving risk landscape. Ensuring an adequate transmission system requires system planners to consider the broad range of future resource, demand, environmental, and security conditions. Planning processes need to include analysis of an expanded set of scenarios for normal and extreme events so that owners and operators can develop proactive plans that will reduce the risk of unacceptable performance.

Emerging Issues

While developing this *LTRA*, NERC and the industry considered trends and developments that have the potential to impact the future reliability of the BPS over the next 10 years and beyond. Discussed below are emerging issues and trends not previously covered in this report that have the potential to impact future long-term projections or resource availability and operations.

Cryptocurrency Impacts on Load and Resources

Due to unique characteristics of the operations associated with cryptocurrency mining, potential growth can have a significant effect on demand and resource projections as well as system operations.

Computer operations for cryptocurrency mining are energy intensive, and mining operators can interrupt or scale operations in response to energy costs. ERCOT continues to see a large volume of interconnect requests from cryptocurrency mining: 9 GW have had planning studies approved of 41 GW that are currently requested.

This new category of large flexible loads is leading some areas to update load forecasting methods to capture the flexibility and price-responsiveness of cryptocurrency mining operations. In anticipation of further growth in large flexible loads, ERCOT and its stakeholders are assessing further operational issues that could emerge, such as the effect on system frequency of sudden changes in large flexible loads.

Blackstart Resources for Restoration in Extreme Conditions

Blackstart generation resources are a critical element of BPS resilience that enables the orderly restoration of grid sections following a blackout. System restoration plans rely on the ability of designated fossil-fuel generators to provide blackstart service.

Recent extreme winter weather has exposed vulnerabilities to generating units and fuel sources that are not adapted to cold temperatures, raising concerns for blackstart unit readiness. The changing resource mix is cause for additional awareness of blackstart capabilities. Currently, few IBRs on the system are capable of grid forming control, one of the necessary components for blackstart resources.

Industry is working to incorporate IBR grid forming technology to address system stability and performance needs, apart from blackstart capabilities. Wholesale markets and resource planners must anticipate the future needs for system restoration services and procure blackstart resources to ensure reliable operations.

Distribution Transformer Supply Chains

The electric industry reports that distribution transformers are in short supply as manufacturer production is unable to keep pace with demand; lead times often exceed two years. Low inventories of replacement distribution transformers could slow restoration efforts following hurricanes and severe storms.[34] A lack of skilled labor for manufacturing transformers is the primary cause of current backlogs. However, access to the grain-oriented electrical steel used in power transformers is the next constraint as the United States has a single producer of grain-oriented electrical steel. New efficiency standards for distribution transformers proposed by the U.S. DOE could further exacerbate the transformer supply shortages by adding requirements that manufacturers are not currently set up to handle.[35]

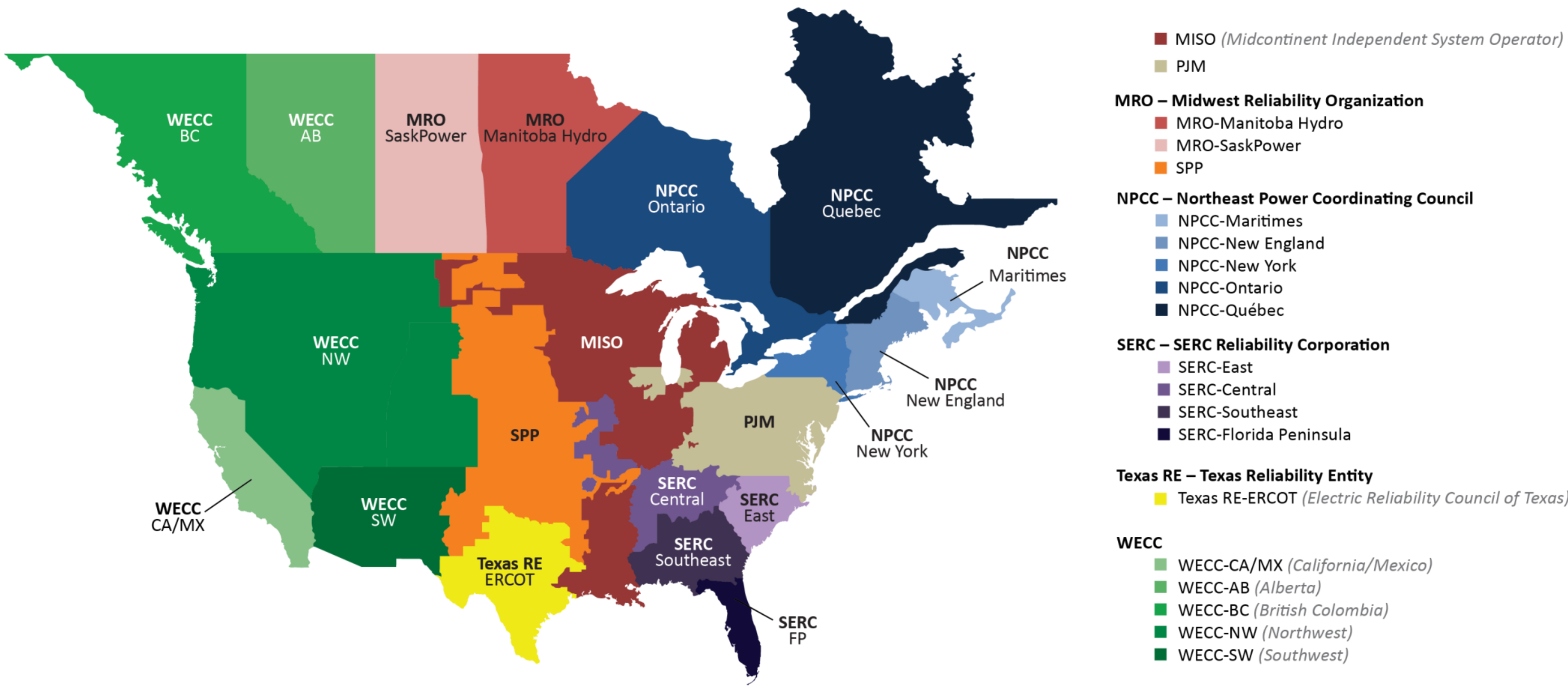
Localized Load Growth

Some areas are experiencing concentrated load growth from industrial and commercial development. Examples of large industrial loads include data centers, smelters, manufacturing centers, hydrogen electrolyzers, and future electrified mass transit or shipping charging stations. Adding large parcels of load on the system can add new uncertainties to peak and hourly load forecasting. For example, data centers have longer operating hours and require more heating and cooling than other commercial buildings. In Texas, crypto mining facilities have connected in recent years that scale their operations (and thus electricity demand) depending on electricity prices. Growth of large, concentrated loads can challenge load forecasting and localized transmission development.

[34] Public Power Article on APPA Survey
[35] Doe Proposes New Efficiency Standards for Distribution Transformers

Regional Assessments Dashboards

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee, 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, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.

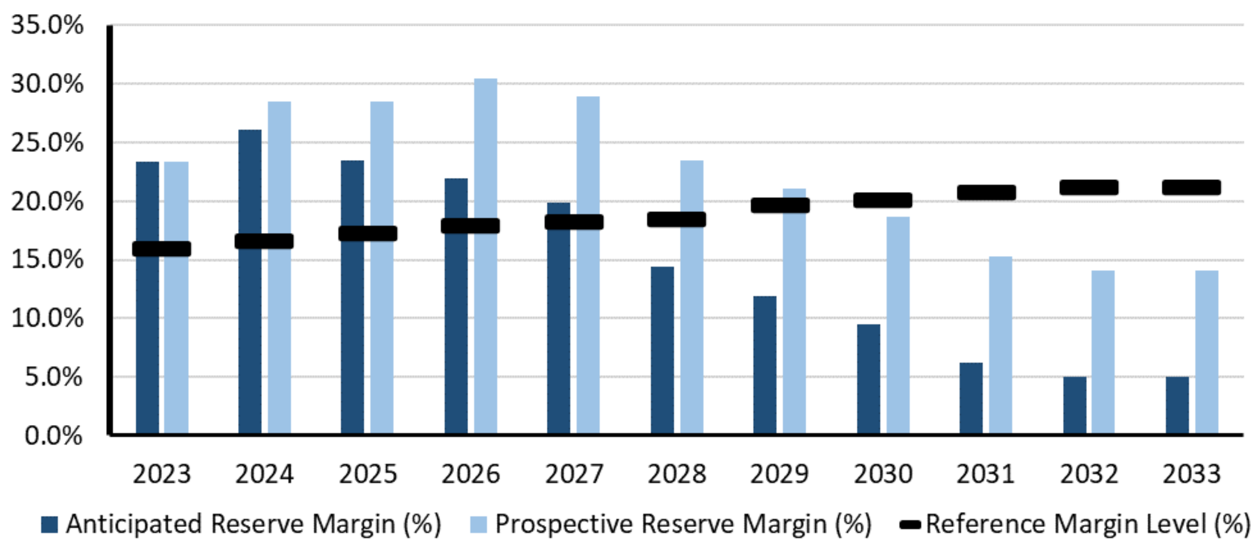


MISO

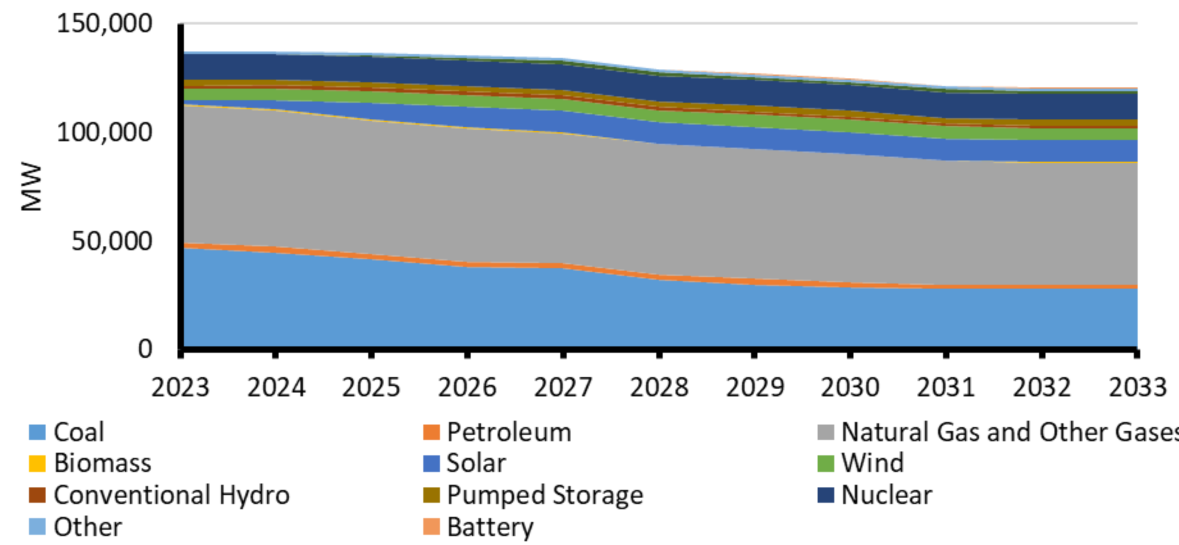
MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy and operating reserve markets that consist of 41 local BAs and over 500 market participants, serving approximately 45 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments. See **High Risk Areas** for more details.

Demand, Resources, and Reserve Margins (Summer)

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	121,933	122,726	123,315	123,888	124,659	125,140	125,591	126,135	126,593	126,593
Demand Response	7,776	7,741	7,798	7,812	7,726	7,728	7,729	7,731	7,728	7,728
Net Internal Demand	114,157	114,985	115,517	116,076	116,933	117,412	117,862	118,404	118,865	118,865
Additions: Tier 1	3,135	6,972	10,936	11,744	11,944	11,945	11,945	11,945	11,945	11,945
Additions: Tier 2	2,694	5,771	9,836	10,495	10,672	10,749	10,749	10,749	10,749	10,749
Additions: Tier 3	163	1,096	3,166	6,615	9,989	12,454	13,332	13,450	13,450	13,450
Net Firm Capacity Transfers	2,125	1,129	1,159	1,057	906	911	806	805	781	781
Existing-Certain and Net Firm Transfers	140,831	134,999	129,924	127,394	121,776	119,493	117,122	113,811	112,865	112,865
Anticipated Reserve Margin (%)	26.1%	23.5%	21.9%	19.9%	14.4%	11.9%	9.5%	6.2%	5.0%	5.0%
Prospective Reserve Margin (%)	28.5%	28.5%	30.5%	28.9%	23.5%	21.1%	18.6%	15.3%	14.0%	14.0%
Reference Margin Level (%)	16.6%	17.2%	17.9%	18.2%	18.4%	19.6%	20.1%	20.7%	21.2%	21.2%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO transitioned to its first year of seasonal capacity auctions (summer, fall, winter, spring). The switch to a seasonal construct improves understanding of non-summer risk and derives seasonal resource accreditation and seasonal resource adequacy requirements. Market responses to higher capacity prices in 2022 and new resource additions have overcome the planning reserve deficits reported in the *2022 LTRA*, and now MISO's ARMs are projected to meet RMLs for the first three years of this assessment period without significant new Tier 2 and Tier 3 resource additions.
- In the past year, coal-fired and nuclear generation capacity has declined mainly due to retirements by 300 MW and 140 MW, respectively. These reductions are not as large as projected last year due to delayed retirements. New wind and wind accreditation increased 725 MW while solar PV and solar PV accreditation increased by 920 MW. The larger increases in resources since last year's LTRA are the result of new natural-gas-fired generators as well as improvements that increased the accredited output contribution from existing natural-gas-fired generators that account for more than 4 GW of added capacity.

MISO Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	44,742	41,656	38,017	37,297	32,266	30,017	28,771	27,856	27,856	27,856
Petroleum	2,719	2,545	2,545	2,545	2,535	2,535	2,310	2,310	2,239	2,239
Natural Gas	62,909	61,454	61,311	59,919	59,755	59,752	59,059	56,842	56,074	56,074
Biomass	374	374	374	339	230	230	169	169	169	169
Solar	4,367	7,446	9,532	9,964	10,054	10,054	10,054	10,054	10,054	10,054
Wind	5,191	5,534	5,622	5,634	5,566	5,541	5,534	5,520	5,516	5,516
Conventional Hydro	1,443	1,443	1,443	1,443	1,443	1,443	1,443	1,307	1,307	1,307
Pumped Storage	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696
Nuclear	11,725	11,725	11,725	11,725	11,725	11,725	11,725	11,725	11,725	11,725
Hybrid	31	375	1,006	1,392	1,476	1,492	1,492	1,492	1,492	1,492
Other	1,299	1,243	1,243	1,243	1,243	1,243	1,243	1,238	1,238	1,238
Battery	0	27	183	213	222	222	222	222	222	222
Total MW	137,496	136,518	135,696	134,410	129,211	126,950	124,719	121,432	120,589	120,589

MISO Assessment

Planning Reserve Margins

In 2023, MISO transitioned to its first year of seasonal capacity auctions (summer, fall, winter, spring). Market responses to higher capacity prices in 2022 and new resource additions have overcome the planning reserve deficits reported in the *2022 LTRA*, and now MISO's summer and winter ARMs are projected to be above the RMLs for the first three years of this assessment period. MISO's summer ARM is projected to be above the RMLs through the 2027 summer. Beginning in 2028, MISO is projected to have a 4.7 GW shortfall if expected generator retirements occur and over 12 GW of new resources are added. It is important to note that there are 50 GW of generation with signed generation interconnection agreements that are not yet on-line and another 200+ GW of new resources within the interconnection queue that are still being evaluated.

With the transition to seasonal auctions, MISO conducted seasonal LOLE studies to identify the RML based on resource installed capacity in each season with the following results: summer 15.9%, fall 25.8%, winter 41.2%, and spring 39.3%.

Energy Assessment and Non-Peak Hour Risk

The introduction of the seasonal planning resource auction and inputs to the process provide more granularity and reliability planning for non-peak hour times during the year; in addition to this change, MISO conducts seasonal resource assessments that evaluate generation availability, outage rates, and forecasted load variation across all four seasons.

Probabilistic Assessments

NERC's most recent probabilistic assessment (2022 ProbA) Base Case results found that most of the LOLHs occur in June–August, corresponding to the typical MISO peak time frame. There are some instances of LOLHs occurring in September–October when seasonal planned outages overlap with high demand. MISO experiences a small amount LOLH in winter when cold temperatures push demand higher than normal.

Base Case Summary of Results (2022 ProbA)			
	2024*	**2024**	**2026**
EUE (MWh)	14.3	193.6	68.8
EUE (PPM)	0.02	0.304	0.108
LOLH (hours per Year)	0.085	0.808	0.393
Operable On-Peak Margin	13.7%	8.1%	13.9%

* Provides the 2020 ProbA Results for Comparison

Non-peak risk drivers tend to be unique to the season. In the fall, the risk of unseasonably high demand overlapping with seasonal planned outages increases the loss-of-load risk. Extreme cold weather, particularly in MISO South, increases demand and causes the risk of loss of load to increase.

In 2023, MISO completed a probabilistic analysis of a risk scenario that examined the effects of modeling seasonal forced outage rates as well as correlated cold weather outages rather than annual average outage rates.[36] The sensitivity analysis shows an increase in the total EUE compared to the Base Case results; these values are 201.8 MWh for EUE and 0.824 hours/year for LOLH. LOLH was relatively unchanged in the Sensitivity Case, which indicates that the duration of load-shed events was similar to the Base Case, but the magnitude of load shed was greater.

The results of MISO's 2023 probabilistic risk scenario indicate that summer remains the season with the largest EUE risk; however, resource outages in other seasons contribute to risk throughout the year. MISO's new seasonal resource adequacy construct is better equipped to identify such risks and procure sufficient capacity to avoid shortfalls.

MISO conducted an internal seasonal LOLE study for inputs in the 2023–2024 seasonal planning resource auction.[37]

Demand

The peak demand forecast for each year in this assessment period has decreased from the *2021 LTRA* forecasts by over 4 GW (3.2%) in the near term and narrowing to 1.7 GW (1.3%) by 2032. The forecast is created using inputs from LSEs in the MISO footprint; MISO does not forecast loads for resource adequacy assessments. MISO performs studies to investigate electrification and transportation industry impacts to load forecasts in its transmission expansion planning process.

[36] See 2022 ProbA Regional Risk Scenarios Report
[37] MISO LOLE Study Report

Demand-Side Management

DR programs continue to play a significant role in MISO's capacity. DR is steady at 7.5–8 GW and is projected to remain constant during this assessment period. MISO's transition to seasonal capacity auctions includes the accreditation of DR and the availability for each season (not strictly the summer peak season).

Distributed Energy Resources

BTM generation contributes about 4.2 GW of capacity in MISO of which about 1.2 GW are distributed solar PV. MISO's transition to seasonal capacity auctions accounts for the availability of DERs in each season. MISO is working with stakeholders to derive adequate methods of aggregating, reporting, and allowing DER participation in MISO markets.

Generation

In the past year, coal-fired and nuclear generation capacity has declined mainly due to retirements by 300 MW and 140 MW, respectively. These reductions are not as large as projected in the *2022 LTRA* as some previously announced retirements have been postponed. New wind and wind accreditation increased 725 MW while solar PV and solar PV accreditation increased 920 MW. The larger increases in resources since last year's LTRA are the result of new natural-gas-fired generators as well as some increases in accredited output contribution from existing natural-gas-fired generators, which account for more than 4GW of added capacity.

There are over 50 GW of generation capacity (predominantly solar PV) with signed generation interconnection agreements in MISO that are projected to come online within the next five years. Some projects have experienced delays in achieving commercial operation due to supply chain issues even as late as the post-agreement phase. MISO tariff changes and interconnection queue processes are reducing interconnection queue timelines.

Recognizing that many projects for new generation terminate the interconnection process before completion, MISO applies a factor to the Tier 2 and Tier 3 resource capacities based on the study phase and likelihood of resources coming on-line. The effect is to reduce the capacity of prospective new resources for more accuracy in long-term planning by accounting for the uncertainty and delays of new resources completing the interconnection process.

Energy Storage

MISO has significant amounts of energy storage (55+GW) currently being studied in the generation interconnection queue that are mostly reflected in Tier 3 of this *2023 LTRA*. MISO does not have information on smaller (distribution level) energy storage in its area.

Capacity Transfers and External Assistance

Net firm transfers have increased since the *2022 LTRA* but are not expected to remain at increased levels. Non-firm transfers across various areas have played a critical role in maintaining reliability during extreme weather events.

Transmission

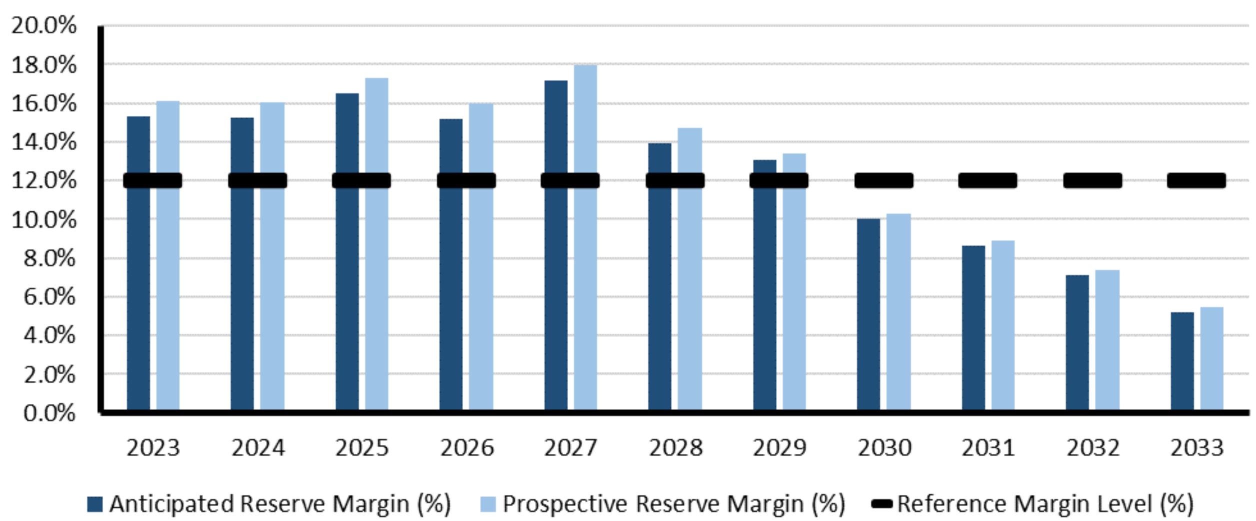
MISO continues to expand its transmission system for reliability and the integration of new resources. In the latest MISO Transmission Expansion Plan, $4.3 billion in transmission projects were approved with $550 million going towards integrating new resources, $550 million going towards baseline reliability projects, and the remainder supporting age- and condition-based needs. The latest approvals in MISO Transmission Expansion Plan (MTEP) 22 build on $10.3 billion in investment contained in MTEP 21 that provides reliability and economic benefits estimated at $23–52 billion across the MISO footprint and facilitates the integration of over 50 GW in new resources. In the *2022 LTRA*, MISO reported approximately 500 miles of new transmission across the footprint. In this *2023 LTRA*, that number has over tripled to near 1,800 miles of new transmission lines across MISO. Next year's MTEP and joint targeted interconnection queue projects with SPP will continue to provide additional transfer capacity across the Midwest and strengthen the transmission grid.

MRO-Manitoba Hydro

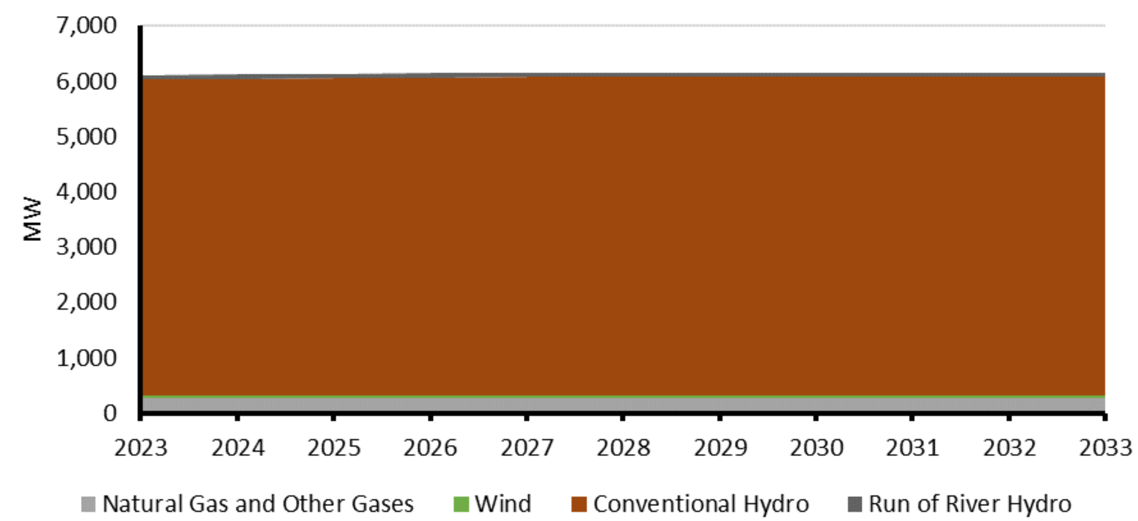
Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 608,500 electricity customers in Manitoba and provides approximately 293,000 natural gas customers in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	4,629	4,636	4,656	4,664	4,863	4,895	4,946	5,009	5,081	5,174
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,629	4,636	4,656	4,664	4,863	4,895	4,946	5,009	5,081	5,174
Additions: Tier 1	91	111	139	152	152	152	152	152	152	152
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	-627	-563	-588	-543	-467	-472	-565	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,244	5,290	5,224	5,313	5,389	5,384	5,291	5,291	5,291	5,291
Anticipated Reserve Margin (%)	15.3%	16.5%	15.2%	17.2%	14.0%	13.1%	10.0%	8.7%	7.1%	5.2%
Prospective Reserve Margin (%)	16.0%	17.3%	15.9%	17.9%	14.7%	13.4%	10.3%	8.9%	7.4%	5.4%
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

- Manitoba Hydro ARM is above the RML throughout the first five years of this assessment period. No resource adequacy issues are anticipated.
- The Manitoba Hydro system is not currently experiencing the large additions of wind and solar generation or thermal generation retirements as seen in some other assessment areas. The predominately hydro nature of the system is not expected to change during this assessment period.

MRO-Manitoba Hydro Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Natural Gas	278	278	278	278	278	278	278	278	278	278
Wind	52	52	31	31	31	31	31	31	31	31
Conventional Hydro	5,702	5,722	5,750	5,763	5,763	5,763	5,763	5,763	5,763	5,763
Run of River Hydro	81	81	81	81	81	81	81	81	81	81
Total MW	6,113	6,133	6,140	6,153	6,153	6,153	6,153	6,153	6,153	6,153

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The ARM for Manitoba does not fall below the RML of 12% during the first five years of this assessment period. No resource adequacy issues are anticipated for the first five years of this assessment period. Manitoba Hydro is nearing the completion of an Integrated Resource Planning process, which will inform resource additions for future assessments.

Energy Assessment and Non-Peak Hour Risk

The primary energy adequacy risk to Manitoba Hydro is severe drought. Manitoba Hydro continually monitors water levels, estimates flows where possible, and uses physically based inflow forecasts to plan its operations. A probabilistic risk evaluation of severe drought is discussed in the following section.

Manitoba Hydro has not identified any ramping issues at the present time and does not anticipate any during the next five years. The inherent flexibility of the hydro resource combined with the limited penetration of variable renewable resources have shielded Manitoba Hydro from ramping issues. In the longer term, Manitoba Hydro will monitor variable renewable penetration and changes in the load shape, including changes from EV charging, to see if ramping demands are increasing.

Probabilistic Assessments

Every two years, Manitoba Hydro prepares a probabilistic assessment for the Manitoba system, most recently in 2022. The 2022 probabilistic assessment was supportive of a 12% RML for the Manitoba system being sufficient to provide a LOLE of less than 0.1 days per year under the study assumptions.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	3.383	28.64	7.23
EUE (PPM)	0.133	1.141	0.287
LOLH (hours per Year)	0.004	0.036	0.007
Operable On-Peak Margin	N/A	13.5%	13.5%

* Provides the 2020 ProbA Results for Comparison

In 2023, Manitoba Hydro completed a probabilistic analysis of a risk scenario that examined the impact of the most significant resource adequacy factor over the long-run, variations in water conditions.[38] In this scenario, hydro resources are modeled at one-tenth percentile low-water conditions. Results indicate that LOLH and EUE values increase for both 2024 and 2026 in the low-water scenario to levels. LOLH, for example, will increase by an order of magnitude to nearly 0.6 hours/year in 2024 in comparison with the Base Case, highlighting the significant impact of low-flow conditions on the predominately hydro system. Since Manitoba Hydro is a small winter-peaking system on the northern edge of a summer peaking system, there is generally assistance available to provide energy to supplement hydro generation in low flow conditions in winter, particularly in off-peak hours. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low waterflow conditions.

Demand

Manitoba Hydro is projecting modest electricity load growth over the next five years. Factors considered in load growth projections include economic activity, electric vehicle adoption, and demand-side management programs in Manitoba operated by Efficiency Manitoba. EV adoption in Manitoba is being driven in part by proposed federal regulations that are expected to require that at least 20% of new vehicles sold in Canada to be zero emissions by 2026, at least 60% by 2030, and 100% by 2035.

Demand-Side Management

Manitoba Hydro's Curtailable Rate Program has approximately 160 MW of load enrolled as resources for peak load management as well as some contingency reserves. The program permits up to 16 curtailments of 4.25 hours each.

Distributed Energy Resources

There is a potential for significant solar PV DER resources in the latter half of this assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar PV DER may be dependent on solar PV subsidies and/or incentives.

[38] NERC 2022 ProbA Regional Risk Scenarios Report

Generation

All seven generating units at the new Keeyask Generating Station are operating, and their completion improves resource adequacy for the remainder of this assessment period. Keeyask Unit 6 is listed as a Tier 1 capacity resource as it is operating but awaiting official commercial operation/designated network resource status. A Tier 1 project to replace eight older and smaller hydro units is being planned for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project of about approximately 50 MW replaces the original hydro units that were mothballed or retired based on economics/end-of-life after about 100 years of operation. No Tier 2 or Tier 3 resources have been assumed to come into service during this assessment period.

Manitoba is not currently experiencing the large additions of wind and solar resources being seen in other areas, so the emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years.

Energy Storage

Manitoba Hydro does not currently anticipate additions of energy storage resources in the next 10 years.

Capacity Transfers and External Assistance

The Manitoba Hydro system is winter peaking and is interconnected to MISO, which is summer peaking. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts, but only if the following conditions occur simultaneously: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. Emergency operating procedures may be necessary under such conditions.

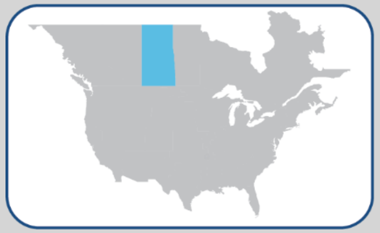
The completion of the Manitoba–Minnesota 500 kV transmission line in June 2020 increased import capability from 700 MW to 1,400 MW and firm export capability from 2,100 MW to 2,983 MW. This new 500 kV line also improved the resilience of the network in the event of transmission contingencies.

Transmission

There are several transmission projects expected to come on-line during this assessment period. Most of the projects are dictated by the need to expand the transmission system to reliably serve growing loads, transmit power to the export market, improve safety, improve import capability, increase efficiency, and connect new generation.

Reliability Issues

Manitoba Hydro is monitoring federal and provincial policy/strategies/regulations related to electricity/energy. The Canadian federal government is considering significant carbon emission regulation. Through Environment and Climate Change Canada, the government is taking multiple steps to develop clean electricity regulations that aim for Canadian electricity generation to achieve net zero greenhouse gas emissions by 2035. This includes requiring generating units to meet a stringent emissions intensity standard (measured in tons CO_2 equivalent per GWh) and pay a price for any remaining emissions. The proposed regulations are still in development and will not be fully implemented until 2035, so it is too early to determine any potential impacts. The province of Manitoba is developing a provincial energy strategy/policy that may be released in 2023. As details are not yet available, it is too early to determine any potential impacts.

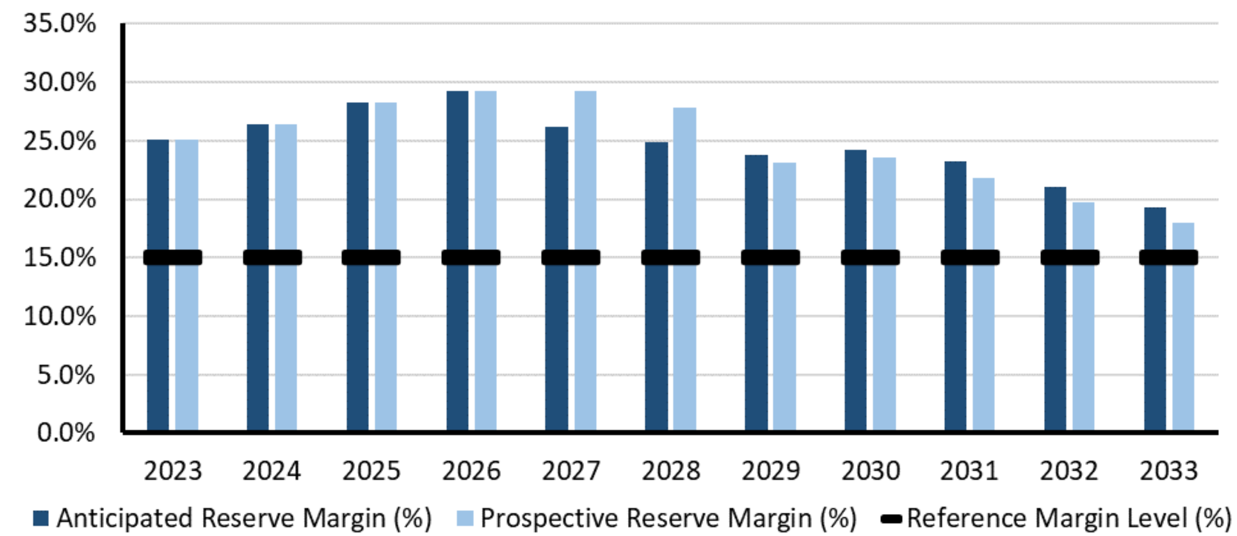


MRO-SaskPower

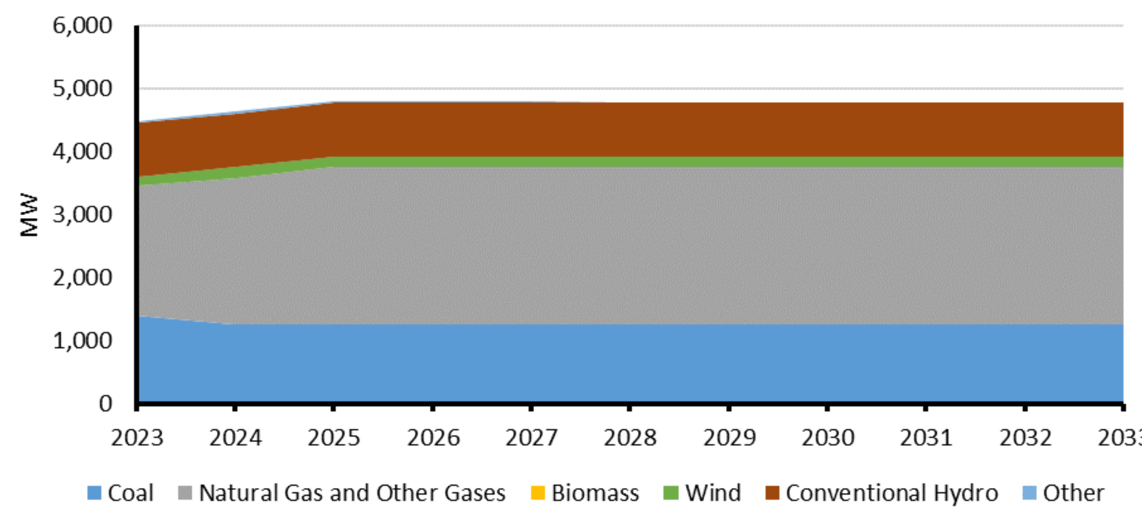
MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles), population of 1.2 million and approximately 550,000 customers. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (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 BES and its interconnections. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	3,880	3,941	4,019	4,065	4,096	4,131	4,153	4,189	4,261	4,324
Demand Response	67	67	67	67	67	67	67	67	67	67
Net Internal Demand	3,813	3,874	3,952	3,998	4,029	4,064	4,086	4,122	4,194	4,257
Additions: Tier 1	416	506	506	506	506	506	506	506	506	506
Additions: Tier 2	0	0	0	421	421	1,173	1,173	1,173	1,173	1,173
Additions: Tier 3	0	0	0	80	80	80	80	80	80	80
Net Firm Capacity Transfers	290	315	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,405	4,461	4,604	4,539	4,524	4,524	4,571	4,572	4,571	4,571
Anticipated Reserve Margin (%)	26.4%	28.2%	29.3%	26.2%	24.9%	23.8%	24.3%	23.2%	21.1%	19.3%
Prospective Reserve Margin (%)	26.4%	28.2%	29.3%	29.2%	27.9%	23.1%	23.6%	21.8%	19.7%	17.9%
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

Highlights

- SaskPower's ARM is above the RML throughout this assessment period. ARMs for winter 2024 are lower than reported in the *2022 LTRA* due to the retirement of generation (one coal-fired and one natural-gas-fired unit with combined capacity of 180 MW), scheduled refurbishment shutdown of an existing generator, and the delay of a new natural-gas-fired generator (45 MW) from December 2024 to April 2025.
- Saskatchewan is adding approximately 734 MW of generation under Tier 1 category within the next five years. This includes a 200 MW wind generation facility, a 10 MW utility-scale solar PV project, two new natural gas facilities totaling 414 MW, and the expansion of two existing natural gas facilities totaling 90 MW. The remaining capacity addition (20 MW) comes from geothermal and other projects.

MRO-Saskpower Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251
Natural Gas	2,334	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501
Biomass	3	3	3	3	3	3	3	3	3	3
Wind	164	164	164	162	162	162	162	162	162	162
Conventional Hydro	860	860	860	860	860	860	860	860	860	860
Other	22	22	17	17	1	1	1	1	1	1
Total MW	4,632	4,800	4,795	4,793	4,777	4,777	4,777	4,777	4,776	4,776

MRO-Saskpower Assessment

Planning Reserve Margins

Saskatchewan uses a criterion of 15% as the RML and has assessed its Planning Reserve Margin for the upcoming 10 years with 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 18–33% and does not fall below the RML.

Energy Assessment and Non-Peak Hour Risk

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. Saskatchewan is evaluating non-peak hours risks and diminishing capacity credits associated with higher penetration levels of VERs as part of the long-term planning process. It is exploring a probabilistic evaluation approach to evaluate VER capacity contribution values.

Probabilistic Assessments

NERC's most recent probabilistic assessment (2022 ProbA) Base Case results found some risk of load loss in both study years, but LOLH remained below 1-day-in-10-year criteria. The major contribution to LOLH and EUE is extended planned maintenance at some of Saskatchewan's hydroelectric units through winter peak season for life extension and upgrade. The planned maintenance on the hydro units is staggered to minimize adverse impacts on system reliability.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	26.5	169.5	117.0
EUE (PPM)	1.1	6.5	4.4
LOLH (hours per Year)	0.3	1.4	0.9
Operable On-Peak Margin	22.8%	23.1%	24.6%

* Provides the 2020 ProbA Results for Comparison

In 2023, SaskPower completed a probabilistic analysis of a risk scenario that examines the system's reliability when a coal unit approaching its planned end-of-life experiences a critical failure leading to premature unavailability. This scenario was selected to better understand the strategy for managing the coal units in Saskatchewan as they approach end of life in the next few years.[39] The results of this scenario reveal higher loss-of-load values in the first year of the assessment as compared to the Base Case. Saskatchewan is on track to add a large natural gas unit facility (377 MW) in-service by April 2024 that should enhance the system reliability for the remainder of this assessment period. SaskPower is also reviewing lay-up strategies for its existing units to support the system's reliability during peak periods.

Demand

Saskatchewan's system peak load forecast is based on 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 1.15% throughout this assessment period.

Demand-Side Management

Saskatchewan's EE and energy conservation programs include incentives-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. DR consists of contracts with industrial customers for interruptible load based under conditions specified in DR programs. The first of these programs provides a curtailable load, currently up to 67 MW, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load that require up to two hours notification time.

Distributed Energy Resources

Current BTM DER installed capacity in Saskatchewan is approximately 42 MW, which includes approximately 40 MW of solar PV, and approximately 2 MW of distributed wind projects. 25 MW of additional DER solar PV are expected to be added in the next five years. The estimated BTM DER installations are incorporated into the load forecast models that are used in supply and transmission planning study models.

Small power producers contribute an additional 5 MW of installed DER capacity (non-BTM) in Saskatchewan. There is currently an existing 8 MW and a potential for up to 20 MW of DERs being added in the next two years based on the currently approved Power Generation Partner programs. These projects are included as generation additions categories but currently their capacity is not considered in reliability planning.

[39] See 2022 ProbA Regional Risk Scenarios Report

Generation

Saskatchewan is adding approximately 734 MW of generation under Tier 1 category within the next five years. This includes a 200 MW wind generation facility and the expansion of two existing natural gas facilities that total 90 MW, two new natural gas facilities that total 414 MW, and the remaining capacity (30 MW) is projected to be geothermal and other projects.

Under Tier 2, over 1,279 MWs of new generation is projected in this assessment period. This includes three large (377 MW), two small (<50 MW) natural gas facilities, and a 100 MW utility-scale project. Natural gas generation is a proxy holder for any new generation needed beyond the medium-term (>5 years), but a portion of this capacity is anticipated to be covered through deploying renewables as well as carbon neutral and low emission generation projects.

Generating resources being planned as Tier 2 and Tier 3 will replace generators planned for retirement prior to deactivation. Therefore, Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

Energy Storage

SaskPower currently has its first BESS, a 20 MW/20 MWh unit, under construction. There are plans to expand this site by an additional 60 MW/60 MWh capacity.

The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/voltage control, primary frequency control, and blackstart.

Capacity Transfers and External Assistance

SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is currently the largest of the three interfaces and is the only interface with long term firm contracts. Capacity transfers from Manitoba would be limited in the events of prior outage of tie lines between SPC and MH as well as nearby transmission facilities supporting the interface. This could only impact reliability if it coincided with the extreme winter or summer peak demand and prior outage of one or more large generating units in Saskatchewan. Risk mitigation is in place through SaskPower's emergency operating procedure that will allow one or more measures, such as short-term imports from other available interfaces (for example Alberta or SPP), initiating DR and short-term load shedding.

Transmission

Approximately 80 km of 230 kV transmission line has been completed this summer and several other transmission projects (approximately 650 circuit km) are under the planning and conceptual phase in the 5-to-10-year assessment period. These projects are driven by load growth, new generation additions and reliability needs.

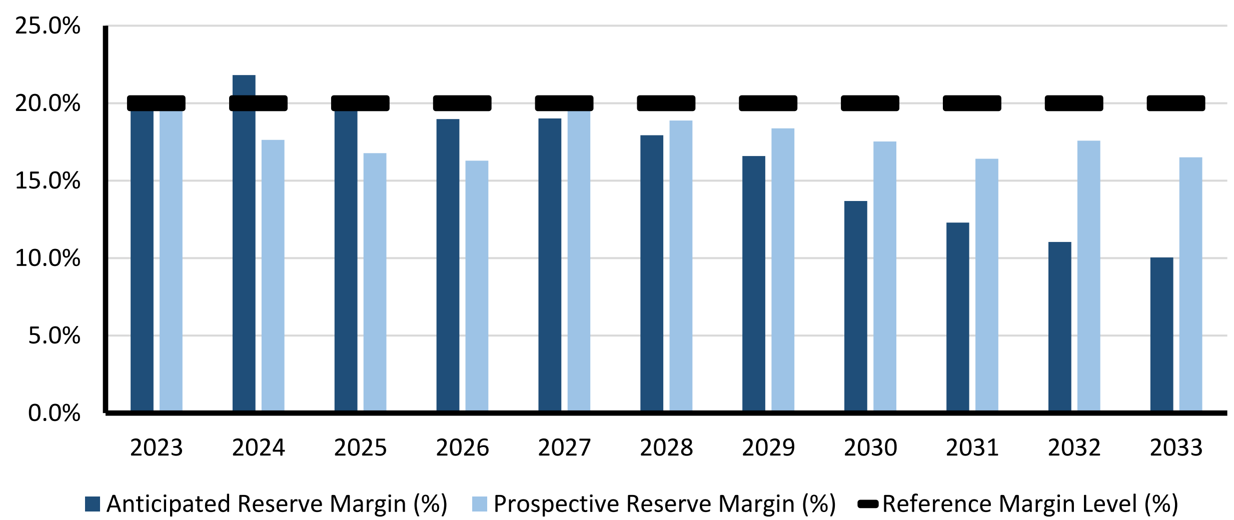
SaskPower performs transmission planning studies including the annual TPL assessment and other applicable periodic studies to meet NERC requirements, System Impact Studies for new load/generation interconnections, generation retirements, transmission service request (TSR) studies, area adequacy studies 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.

NPCC-Maritimes

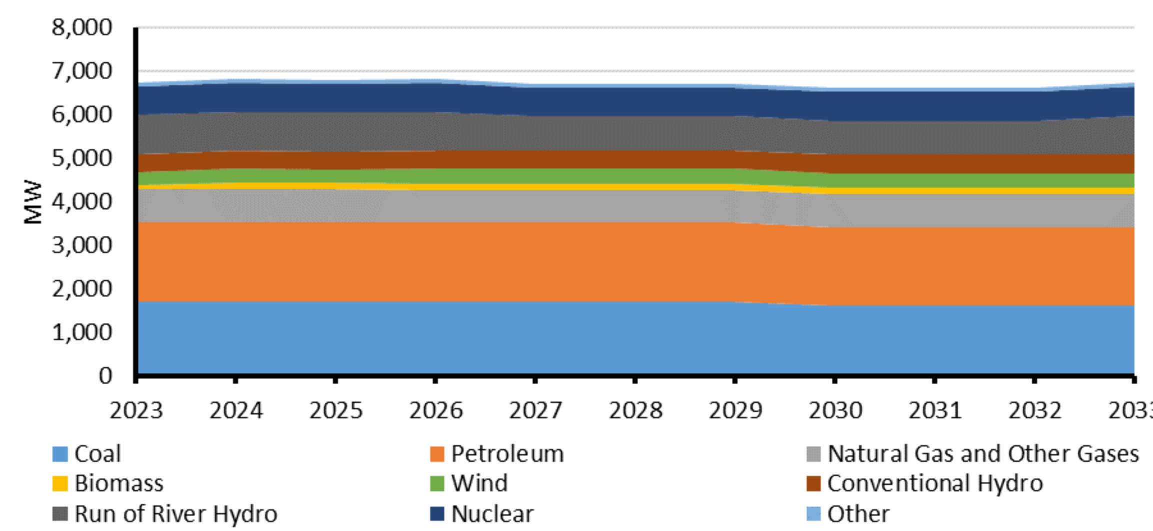
The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two BA areas (New Brunswick and Nova Scotia). It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI), and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a total population of 2 million people. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	5,911	5,951	5,999	6,052	6,105	6,171	6,240	6,314	6,381	6,451
Demand Response	266	285	290	290	289	288	288	287	287	286
Net Internal Demand	5,644	5,665	5,709	5,763	5,816	5,883	5,953	6,027	6,095	6,165
Additions: Tier 1	34	34	52	52	52	52	52	52	52	52
Additions: Tier 2	10	36	93	276	451	960	1,083	1,103	1,253	1,253
Additions: Tier 3	0	32	105	125	495	515	535	555	575	590
Net Firm Capacity Transfers	55	23	-32	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	6,841	6,792	6,740	6,807	6,807	6,807	6,716	6,716	6,716	6,732
Anticipated Reserve Margin (%)	21.8%	20.5%	19.0%	19.0%	17.9%	16.6%	13.7%	12.3%	11.0%	10.0%
Prospective Reserve Margin (%)	17.6%	16.8%	16.3%	19.5%	18.9%	18.4%	17.5%	16.4%	17.6%	16.5%
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

- Since the *2022 LTRA*, winter peak demand forecasts for this assessment area have risen. As a result, ARMs are currently projected to fall below the RML of 20% beginning in 2026.

NPCC-Maritimes Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	1,695	1,695	1,695	1,695	1,695	1,695	1,604	1,604	1,604	1,604
Petroleum	1,829	1,823	1,818	1,818	1,818	1,818	1,818	1,818	1,818	1,818
Natural Gas	760	760	760	760	760	760	760	760	760	760
Biomass	148	148	148	148	148	148	148	148	148	148
Wind	322	310	328	328	328	328	328	328	328	328
Conventional Hydro	418	418	418	418	418	418	418	418	418	418
Run of River Hydro	902	902	902	792	792	792	792	792	792	902
Nuclear	663	663	671	671	671	671	671	671	671	671
Other	90	90	90	90	90	90	90	90	90	90
Total MW	6,827	6,809	6,830	6,720	6,720	6,720	6,629	6,629	6,629	6,739

NPCC-Maritimes Assessment

Planning Reserve Margins

The reference reserve margin level that is used for evaluating the New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM) sub-areas that make up the Maritimes area is 20% of firm load. The 20% criterion is not a mandated requirement. The ARM in the first five years for Maritimes ranges between 19% to 22% during the winter period and between 73% to 83% during the summer period of this LTRA study.

Energy Assessment and Non-Peak Hour Risk

The ARM level during off-peak season for the Maritimes areas ranges between 73% to 83%. During off peak hours, Maritimes has surplus generation available to meet the area's energy needs and hence there are no constraints with converting the capacity to energy during these times.

Probabilistic Assessments

The two BAs within Maritimes, as members of NPCC, jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three- to five-year forward-looking periods for both Maritimes' transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual seasonal probabilistic assessments, which provide an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	1.125	1.838	3.869
EUE (PPM)	0.039	0.06	0.138
LOLH (hours per Year)	0.023	0.023	0.071
Operable On-Peak Margin	16.7%	25%	22.9%

* Provides the 2020 ProbA Results for Comparison

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. 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 this LTRA assessment period. The Maritimes area peak loads are expected to increase by 11.3% during summer and by 10% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 1.1% in summer and 1% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 6.2% during the 10-year assessment period for an average growth of 0.6% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs with 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. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 17 MW to 162 MW while the annual amounts for winter peak demand reductions rise from 88 MW to 551 MW.[40]

Distributed Energy Resources

The DER installed capacity in NS is approximately 230 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff and BTM solar PV.

The LTRA wind capacity for NB, NS and PEI is de-rated between 18% and 33% with probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding Northern Maine which uses seasonal capacity factors. BTM solar PV is assumed to have an ELCC of 0% during winter period. The Maritimes Area has shown embedded BTM solar PV projections of 99 MW in 2023 rising to 669 MW by 2033. These projects include distributed small-scale solar PV (mainly rooftop) that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar PV 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 area's system peak, which occurs either before sunrise or after sunset in the winter period.

[40] Current and projected EE effects based on actual and forecasted customer adoption of various demand-side management 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.

Generation

In NB, a hydro facility of 4 MW nameplate capacity shall reach its end of life and is planned to be retired at the end of 2023. NB assumes that 28 MW of diesel-fired generation will be extended starting in 2025 and that recently upgraded 290 MW of natural-gas-fueled resources will be completed in 2023. In NB, unconfirmed retirements include a 98 MW power purchase agreement contract that will come to an end in 2024–2025. An anticipated replacement power purchase agreement contract, a long-term firm energy contract from neighboring jurisdictions, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain overall resource adequacy.

In Nova Scotia, Tier 1 resources include wind projects with a total nameplate capacity of 502 MW phased-in from 2024–2027 with an ELCC of 10%. Tier 2 resources in NS include a 200 MW of BESS (2026–2032), 520 MW of combustion turbines (2027–2033), a 150 MW conversion of a coal-fired unit to natural gas (2028), and 459 MW conversion of coal-fire units to oil (2030). Tier 3 resources in NS include natural gas additions (combustion turbines) of 350 MW in 2029 and new wind generation with a nameplate capacity of 1,600 MW phased in from 2026–2033. These Tier 3 resource additions are anticipated to facilitate the retirement of additional coal-fired generation by 2030. However, these retirements have not been included in the assessment due to their uncertainty.

Small amounts of new solar PV generation capacity (Tier 2) of up to 31 MW are expected to be installed in PEI in the fall of year 2023. PEI also plans to add a new 10 MW of hybrid energy storage (Tier 2) during the year 2023.

Tier 3 additions include wind projects with a total nameplate capacity of 1,840 MW starting year 2025, solar PV projects of 200 MW nameplate capacity starting year 2025 and 400 MW nameplate capacity of dual fueled combustion turbines starting year 2027.

NB de-rates its wind capacity with a calculated year-round equivalent capacity of 33%. NS and PEI de-rate wind capacity to 18% and 17%, respectively, of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 200 MW (4-hour duration) nameplate capacity standalone BESS added as a Tier 2 resource phased-in from 2026–2032. This grid-scale project will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 2 resource starting fall of 2023. This project will provide storage option to the output from the 10 MW solar PV facility that is planned to be coming on-line during the same time frame. This project will provide fuel savings and may provide additional reliability if a generation outage occurs.

NB Power has not included any BESS in the 2023 LTRA submission; however, the value of energy storage options is expected to increase as the technology improves and NB’s smart grid network develops. NB Power issued a request for expressions of interest for new renewable generation sources, including 200 MW of wind, 15 MW of solar PV, 5 MW of tidal, and 50 MW of 4-hour duration BESS in February of 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of BESS resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with BESS options as well as dispatching these resources to reduce/shift peaks and/or balance intermittent resources, such as wind, to provide additional flexibility to the system.

Capacity Transfers and External Assistance

ProbA studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission

There are no new transmission projects in the Maritimes area.

Reliability Issues

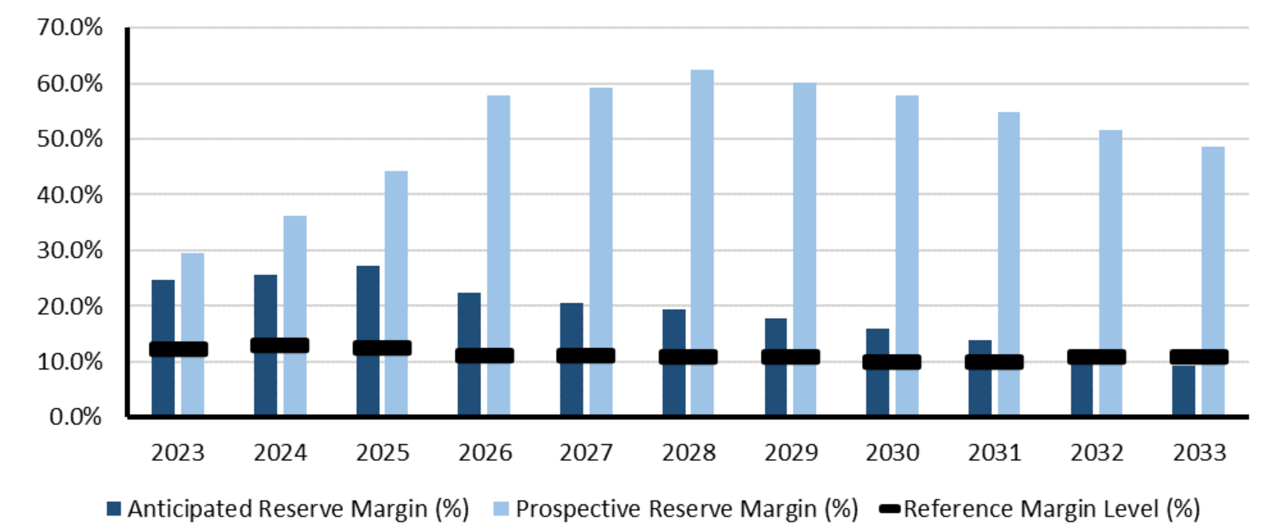
The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (de-rated), dual fuel oil/gas, tie benefits, and biomass with no one type feeding more than about 27% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges for resources during this assessment period.

NPCC-New England

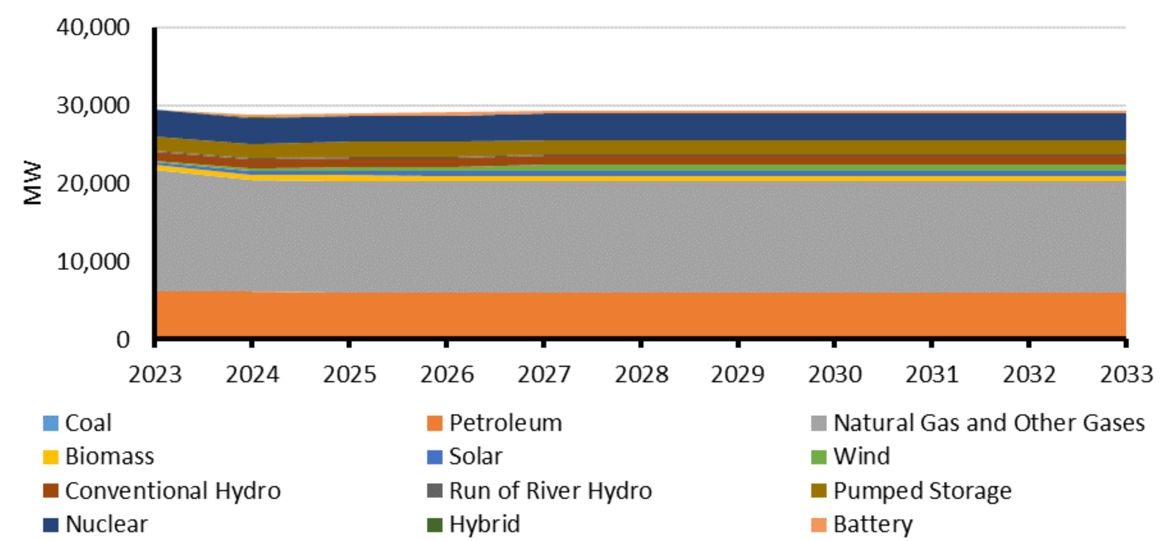
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO-NE Inc. ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation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

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	24,633	24,708	24,866	25,052	25,307	25,636	26,036	26,505	27,046	27,598
Demand Response	661	669	623	623	623	623	623	623	623	623
Net Internal Demand	23,972	24,039	24,243	24,429	24,684	25,013	25,413	25,882	26,423	26,975
Additions: Tier 1	708	1,084	1,111	1,380	1,380	1,380	1,380	1,380	1,380	1,380
Additions: Tier 2	1,376	1,836	6,338	7,181	8,392	8,392	8,392	8,392	8,392	8,392
Additions: Tier 3	1,130	2,199	3,625	9,514	11,306	11,836	12,525	12,525	12,525	12,525
Net Firm Capacity Transfers	1,297	1,504	567	84	84	84	84	84	84	84
Existing-Certain and Net Firm Transfers	29,408	29,505	28,552	28,068	28,068	28,068	28,068	28,068	28,068	28,068
Anticipated Reserve Margin (%)	25.6%	27.2%	22.4%	20.5%	19.3%	17.7%	15.9%	13.8%	11.4%	9.2%
Prospective Reserve Margin (%)	36.2%	44.2%	57.7%	59.1%	62.4%	60.2%	57.7%	54.9%	51.7%	48.6%
Reference Margin Level (%)	12.9%	12.6%	11.0%	11.0%	11.0%	11.0%	10.0%	10.0%	11.0%	11.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- New England is forecast to have the resources needed to meet consumer demand for electricity through the first nine years of the 10-year LTRA assessment period. In the last year of the assessment, in the summer of 2033, the summer ARM of 9.2% falls below the annual RML of 11.0%. However, at this time, ISO-NE does not expect the need to procure capacity additions to mitigate potential resource adequacy issues forecast for the last summer of the 10-year LTRA.
- Beyond the LTRA assessment period, additional imports of Canadian hydroelectricity, offshore wind, and new technologies, such as longer-duration energy storage, will likely continue the trend toward a cleaner, albeit more complex, power system.
- ISO-NE is addressing the issues brought on by grid transformation through a number of planning, operational, and market measures.

NPCC-New England Fuel Composition

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	437	437	437	437	437	437	437	437	437	437
Petroleum	5,635	5,562	5,546	5,546	5,546	5,546	5,546	5,546	5,546	5,546
Natural Gas	14,311	14,328	14,328	14,328	14,328	14,328	14,328	14,328	14,328	14,328
Biomass	749	711	711	711	711	711	711	711	711	711
Solar	424	542	568	568	568	568	568	568	568	568
Wind	341	583	583	852	852	852	852	852	852	852
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	133	133	133	133	133	133	133	133	133	133
Pumped Storage	1,861	1,861	1,861	1,861	1,861	1,861	1,861	1,861	1,861	1,861
Nuclear	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354
Hybrid	34	34	34	34	34	34	34	34	34	34
Battery	386	386	386	386	386	386	386	386	386	386
Total MW	28,820	29,086	29,095	29,364	29,364	29,364	29,364	29,364	29,364	29,364

NPCC-New England Assessment

New England is forecast to have the resources needed to meet consumer demand for electricity through the first nine years of the 10-year LTRA assessment period. In the last year of the assessment, in the summer of 2033, the summer ARM of 9.2% falls below the annual RML of 11.0%, a 1.8% (-494 MW) shortfall. If only 6% (about 500 MW) of the total Tier 2 resources (8,392 MW) materializes in the future, the summer shortfall in the final year of the assessment would be mitigated. However, at this time, ISO-NE does not expect the need to procure capacity additions to mitigate potential resource adequacy issues forecast for the last summer of the 10-year LTRA.

With the widespread development of renewable and clean energy resources, the BPS will emit lower air emissions. Beyond the LTRA assessment period, additional imports of Canadian hydroelectricity, offshore wind, and new technologies (e.g., longer duration energy storage) will likely continue the trend toward a cleaner, albeit more complex, power system. ISO-NE is addressing these issues brought on by grid transformation through a number of planning, operational, and market measures.

Planning Reserve Margins

ISO-NE's seasonal ARM is based on the capacity needed to meet the ISO-NE and NPCC 1-day-in-10 years LOLE resource planning reliability criterion. The capacity needed, referred to as the installed capacity requirement (ICR), varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, covering four years into the future. The latest calculations result in an annual RML of 12.3% in 2023, 12.9% in 2024, 12.6% in 2025, and 11.0% in 2026 and 2027. For the years beyond ISO-NE's forward capacity market (FCM) time frame, this assessment uses the annual RML associated with the representative future ICRs calculated for 2028 through 2032. ISO-NE assumes a continuation of the annual RML in 2032 for the annual RML in 2033. These annual RMLs range from a low of 10.0% in 2030 and 2031 to a high of 11.0% in 2028, 2029, 2032 and 2033.

Energy Assessment and Non-Peak Hour Risk

ISO-NE's probabilistic and deterministic study results indicate that there are sufficient capacity resources to meet forecasts of seasonal peak and energy demands for nine years out of the 10-year LTRA assessment period. However, a standing concern is whether there will be sufficient fuel available for resources to turn capacity into electricity to satisfy both demand and required operating reserves during an extended cold spell, a series of cold spells, or a long-term critical infrastructure or supply chain force majeure scenario.

ISO-NE regularly prepares outlooks for both energy demand and production. Forecasts of weather, transmission topology, resource capability, fuel inventories, known and forced outages, regional gas pipeline or liquid fuel constraints, and projected imports/exports all factor into this outlook for New England's energy production capability. If the regional supply/demand balance is negative, projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential electricity shortages should incentivize market participants to procure the necessary fuel needed to support future ISO dispatch orders.

ISO-NE has undertaken several new projects to develop more enhanced deterministic and probabilistic energy security analyses. For instance, ISO-NE is working with the Electric Power Research Institute to conduct probabilistic energy adequacy studies for New England under extreme weather events. These studies establish a framework for risk analysis that can be updated as climate projections are refined and the resource mix evolves. The energy adequacy risk profile is dynamic and will be a function of the evolution of both supply and demand profiles. Preliminary results for 2027 winter events, 2027 summer events, 2032 summer events, and 2032 winter events reveal a range of energy shortfall risks and associated probabilities.[41] In terms of magnitude and probability, these baseline results indicate that energy shortfall risks in the near-term appear manageable over a 21-day period. Sensitivity analysis of 2032 worst-case scenarios indicates an increasing energy shortfall risk profile between 2027 and 2032.

ISO-NE and stakeholders are working on near- and long-term market improvements to expand the existing suite of energy and ancillary services that will cost-effectively address uncertainties in firm electricity production. All of these activities directly enhance overall BPS energy security.

Probabilistic Assessments

ISO-NE conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC/NERC reliability requirements. In the transmission assessment domain, revisions to ISO-NE planning processes now reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated transmission planning activities with neighboring systems will continue and help

[41] Results of the preliminary EPRI/ISO-NE studies reveal similar energy adequacy risk both with and without the Everett Marine Terminal LNG facility in-service.

support the New England states' policy objectives of providing access to a greater diversity of clean resources to meet environmental compliance obligations.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	58.62	0.937	0.551
EUE (PPM)	0.471	0.007	0.004
LOLH (hours per Year)	0.095	0.002	0.002
Operable On-Peak Margin	9.8%	32.6%	27.8%

* Provides the 2020 ProbA Results for Comparison

As expected from the 2022 ProbA risk scenario, the EUE and LOLH remain close to zero with increased capacity, decreasing demand, and no major reported Tier 1 resources after 2024. The New England area is currently summer-peaking, and the EUE risk occurs during the summer months; however, the EUE values are negligible.

Demand

Over the 10-year planning period, the forecast net internal summer peak demand increases by 2,993 MW from 24,605 MW in 2023 to 27,598 MW in 2033. The corresponding net internal winter peak demand forecast increases by 7,183 MW from 20,269 MW in 2023–2024 to 27,452 MW in 2033–2034. Net energy for load is forecast to grow by 33,006 GWh from 120,552 GWh in 2023 to 153,558 GWh in 2033.

The forecast for summer peak load reductions due to EE and conservation is expected to increase by 436 MW from 1,969 MW in 2023 to 2,405 MW in 2033. This demand reduction is represented in the reported total internal demand of the Demand, Resources and Reserve Margins table.

Currently, New England has 981 MW (3,366 MW nameplate) of BTM-PV. BTM-PV is forecast to grow to 1,116 MW (6,553 MW nameplate) by 2033. The BTM-PV peak load reduction values are calculated as a percentage of nameplate. The percentages include the effect of diminishing PV production at time of system peak as increasing PV penetrations shift the timing of summer peaks to later in the day. As such, the BTM-PV summer peak load reduction values decrease from 29.1% of nameplate in 2023 to 17.0% in 2033. Like EE and conservation, BTM-PV is also a demand reduction represented in the reported Total Internal Demand of the Demand, Resources and Reserve Margins table on the NPCC-New England dashboard.

Demand-Side Management

New England currently has 564 MW of controllable and dispatchable DR resources, and that amount is projected to grow by 59 MW to 623 MW by 2033. The area also currently has over 3,253 MW of passive demand-side management resources that participate in the regional FCM. This amount is projected to decrease by 936 MW to 2,317 MW by 2032.

Distributed Energy Resources

Approximately 2,550 MW (nameplate) of settlement-only generation does not participate in ISO-NE's FCM. Of this total, approximately 2,400 MW is made up of units or stations smaller than 5 MW each.

Generation

Future capacity required to comply with NPCC's resource planning criterion is procured through ISO-NE's FCM. Studies of projected system conditions show that developing new resources near load centers, particularly in Northeast Massachusetts/Boston and Southeastern Massachusetts and Rhode Island, would provide the greatest reliability benefit. To the extent that new resources are developed to help balance supply with demand, the BPS would require fewer transmission upgrades and ancillary services and would exhibit less congestion and losses.

The continued reliance on natural-gas-fired generation still exposes New England to the reliability impacts from the fleet's lack of firm gas pipeline transportation contracting and its dependence upon uncertain liquified natural gas import deliveries. Natural gas sector infrastructure contingencies can become electric sector reliability risks during any time of the year. ISO-NE and interregional reliability organizations have identified these risks in a number of energy security studies and assessments, and ISO-NE has taken a number of remedial actions to improve the overall gas/electric interface. The development of renewable resources with energy storage, imports from neighboring areas, and fast-start and flexible ramping resources along with the continued investment in EE/conservation measures within both the electric and natural gas sectors are also part of the overall reliability solution.

Future environmental regulations, public policies, and economic considerations will all affect the operation of existing resources and the mix of new resources. As existing oil- and coal-fired generators retire, their replacements would likely be predominantly renewable sources of energy, notably wind and solar PV. Federal and state policies, such as those that promote EE, PV, and wind resources, will continue to affect the planning process. Carbon emission reduction targets will continue to be the key regional constraint on electricity production by fossil-fueled generating units.

Energy Storage

ISO-NE currently has 1,861 MW of pumped-storage hydroelectric stations, 61 MW of stand-alone BESS, and 27 MW of co-located and integrated hybrid BESS (summer ratings). These amounts are expected to grow over the 10-year LTRA assessment period. ISO-NE reports 386 MW of stand-alone BESS and 34 MW of co-located/integrated hybrid BESS for the summer of 2033.

Capacity Transfers and External Assistance

New England is interconnected with the three Bas of Québec, Maritimes, and New York. ISO-NE considers the tie benefits associated with these Bas to meet the regional resource adequacy criterion and to prevent over-reliance on such assistance. 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 567 MW to 1,504 MW during the 2023–2026 summer periods. There is one long-term firm import contract of 84 MW that extends through the 10-year LTRA assessment period. In addition, there are no firm exports identified over the 10-year LTRA assessment period.

As a result of updates to the permitting status of the New England Clean Energy Connect inter-area transmission line and supporting energy contract, which is scheduled for commercial operation in December of 2024 and starting in the summer of 2025, ISO-NE is reporting an expected import from Québec in the amount of 1,090 MW/hr. This contract is not reported by ISO-NE for the winter periods due to Québec's own load needs for serving its winter-peaking system.

Transmission

Transmission expansion in 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 DERs and VERs by using IBRs, and changes to mandatory planning criteria promulgated by NERC, NPCC, and regional stakeholders have driven the need for longer-term transmission assessments.

Future reliable and economic performance of the BPS is expected to continue to improve as a result of approximately $1.5 billion of planned transmission upgrades over the next 10 years, much of which is still under construction. Generator retirements, the integration of many DERs and VERs, the use of IBR technologies, and issues rising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy. Transmission assessments and resultant plans are being developed throughout the area to meet these future system needs.

Reliability Issues

New England's BPS is transitioning to a system with a growing number of renewables, clean energy resources, VERs and DERs. The rapid implementation of revised interconnection standards for VERs and DERs is vital to ensure overall BPS reliability and facilitate the economic development of IBRs.
As of summer 2023, constraints on global, regional, and local supply chains are affecting the procurement of new (or needed) BPS infrastructure due to the lack of raw materials, manufacturing limitations, labor shortages, and high inflation and interest rates. This has led to some previously signed long-term, off-shore wind contracts being renegotiated and/or canceled.

New England has already experienced constraints on electricity production due to a lack of natural gas for the power sector during winter. In response, ISO-NE has been a key player at the national level in promoting BPS reliability through sharing of lessons learned and best practices and now through initiating the performance of more detailed and in-depth BPS energy assessments. Additionally, to address winter energy security challenges, ISO-NE and regional stakeholders developed and put in place a two-year program to compensate certain resources that provide energy security during the winters of 2023–2024 and 2024–2025 (from December to February). ISO-NE's Inventoried Energy Program is a voluntary program designed to provide incremental, winter period compensation for participants that maintain inventoried energy for their assets during extreme cold periods when energy security is most stressed.[42]

The just-in-time delivery of a generators fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy either through long-term energy storage solutions that can capture and store renewable power or through the use of dispatchable resources, whether these dispatchable resources are carbon emitting or not.

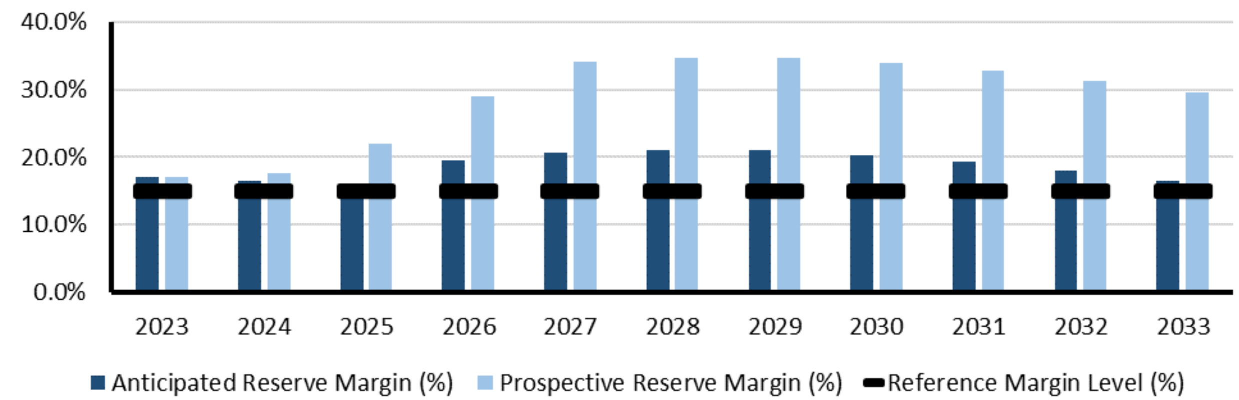
[42] Beginning September 1, 2023, only participants using the fuel types of oil, refuse, batteries, pumped storage and natural gas (with firm supply and transport) may elect to participate in IEP.

NPCC-New York

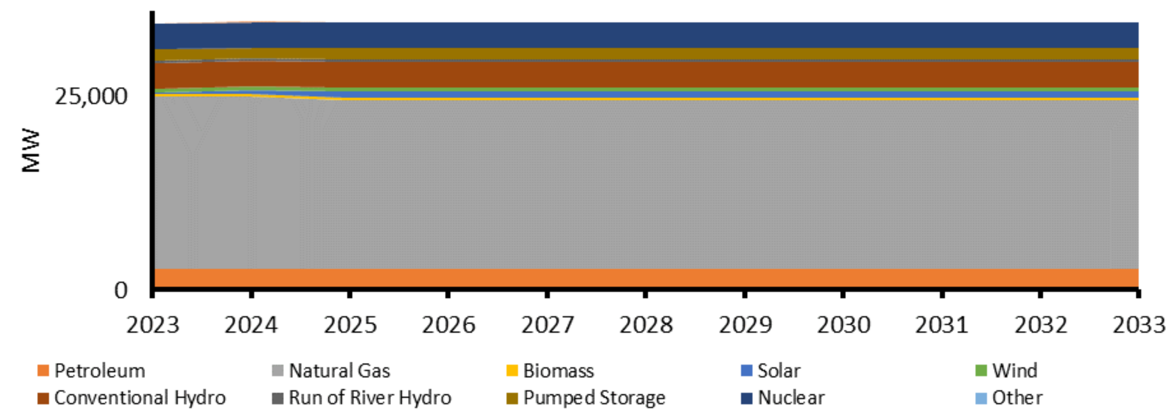
NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within New York. NYISO supports reliability primarily through three complementary markets: energy, ancillary services, and capacity. The transmission grid of New York State encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves the electricity needs of 19.6 million people. New York experienced its all-time peak demand of 33,956 MW in the summer of 2013. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	32,280	32,390	32,440	32,410	32,310	32,300	32,490	32,750	33,110	33,520
Demand Response	860	860	860	860	860	860	860	860	860	860
Net Internal Demand	31,420	31,530	31,580	31,550	31,450	31,440	31,630	31,890	32,250	32,660
Additions: Tier 1	410	877	888	888	888	888	888	888	888	888
Additions: Tier 2	415	2,124	3,000	4,305	4,305	4,305	4,305	4,305	4,305	4,305
Additions: Tier 3	3,796	6,124	10,171	12,204	12,204	12,204	12,204	12,204	12,204	12,204
Net Firm Capacity Transfers	1,932	1,815	3,212	3,518	3,518	3,518	3,518	3,518	3,518	3,518
Existing-Certain and Net Firm Transfers	36,152	35,445	36,842	37,148	37,148	37,148	37,148	37,148	37,148	37,148
Anticipated Reserve Margin (%)*	16.4%	15.2%	19.5%	20.6%	20.9%	21.0%	20.3%	19.3%	17.9%	16.5%
Prospective Reserve Margin (%)	17.7%	21.9%	29.0%	34.2%	34.6%	34.7%	33.9%	32.8%	31.3%	29.6%
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

*Values are with wind derated by 82% wind, solar by 43% and run-of-river by 60% for summer capability period. Additionally, the proposed 1,250 MW Champlain-Hudson Power Express HVDC from Québec to New York City is assumed in the net transfers starting 2026.

**The NERC LTRA RML is 15% and it 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, 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 2023–2024 IRM at 20%. All values in the IRM calculation are based upon full installed capacity MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

Highlights

- Public policies, such as the 2019 Climate Leadership and Community Protection Act (CLCPA), are driving rapid changes in New York's electric system and impacting how electricity is produced, transmitted, and consumed. The transition to a cleaner grid in New York is leading to an electric system that will be increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Recent assessments reveal that reliability margins are shrinking. Electrification programs are driving demand for electricity higher, and New York is projected to become winter peaking in the future. Largely in response to public policies, fossil fuel generators are retiring at a faster pace than new renewable supply is entering service. The potential for delays in construction of new supply and transmission, higher than forecasted demand, and extreme weather could threaten grid reliability and resilience.
- NYISO's reliability studies identified actionable reliability needs starting 2025 in New York City, resulting in NYISO solicitating for market-based and regulated backstop solutions (the solutions can be generation, DR, or transmission, or combinations). The need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City that is affected by state legislation for emissions limits, known as The Peaker Rule.[43]
- Driven by public polices, new supply, load, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection process balances developer needs with grid reliability. Efforts are underway to make this process more efficient while protecting grid reliability. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway.
- To achieve the mandates of the CLCPA, new emission-free supply with the necessary reliability services will be needed to replace the capabilities of today's generation. 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 and steep ramping requirements. Such new emission-free supply is not yet available on a commercial scale.
- New wholesale electricity market rules are supporting the grid in transition. These markets are critical for a reliable transition. Wholesale electricity markets are open to significant investment in wind, solar, and BESS. Peak load management needs to be integrated as a measure to facilitate achievement of CLCPA targets. By lowering peak load and avoiding system buildout to serve the highest demand hour, less dispatchable emission-free resource build-out will be needed and fewer fossil fuel-fired plants will be needed to meet lower peaks during the transition.

NPCC-New York Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Petroleum	2,632	2,632	2,632	2,632	2,632	2,632	2,632	2,632	2,632	2,632
Natural Gas	22,384	21,794	21,794	21,794	21,794	21,794	21,794	21,794	21,794	21,794
Biomass	330	330	330	330	330	330	330	330	330	330
Solar	379	803	814	814	814	814	814	814	814	814
Wind	490	533	533	533	533	533	533	533	533	533
Conventional Hydro	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305
Run of River Hydro	379	379	379	379	379	379	379	379	379	379
Pumped Storage	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Nuclear	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305	3,305
Battery	20	20	20	20	20	20	20	20	20	20
Total MW	34,631	34,507	34,518	34,518	34,518	34,518	34,518	34,518	34,518	34,518

[43] New York Department of Environmental Conservation Peaker Rule

NPCC-New York Assessment

Planning Reserve Margins

The LTRA Planning Reserve Margins are above 15% throughout the 10-year assessment period; however, the system margins are narrowing. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate the system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's *2022 Reliability Needs Assessment*, completed on November 2022, identified that the New York Control Area (NYCA) LOLE is below its "one day in 10 years" criterion for the 10-year study period.

NYISO also provides support to the New York State Reliability Council (NYSRC) in conducting an annual IRM[44] 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 NPCC and NYSRC resource adequacy criterion of "one day in 10 years." The current IRM for the 2023–2024 capability year is 20% of the forecasted NYCA peak load. 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, NYISO performs an annual study to identify the locational minimum installed capacity requirements[45] for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

The Climate Leadership and Community Protection Act decarbonization targets span over all major industries and are a main driver for the electric system changes. NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, dispatchable emission-free resources and long-duration resources are needed to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes, such as 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. Additionally, although new transmission is being built, more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range energy assessments (10-year and beyond) in the is accounted for in the 8,760 hours per year simulations in the resource adequacy studies as part of the RPP and the production cost simulations as part of the system and resource outlook study.

NYISO Grid Operations performs or assists in performing energy assessments, including, but not limited to, a fuel and energy security study and ongoing assessments, a study that assesses potential impacts related to climate change, and weekly analysis based on the results of reporting by generation resources through NYISO's Generator and Fuel Emissions Reporting data portal. NYISO grid operations also performs an internal energy analysis at least weekly based on data and information reported by supply resources through NYISO Generator and Fuel Emissions Reporting system. Resources provide data and information on an annual, weekly, and as needed basis considering system operating conditions. This analysis has the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement and certain combined-cycle natural gas units participate in a Minimum Oil Burn program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called upon to fuel generation during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and other studies)

NYISO performs probabilistic assessments by using General Electric's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes as well as to determine annual Locational Minimum Installed Capacity Requirements (LCR). NYISO also pursued capacity accreditation market rules to more accurately reflect capacity market suppliers' contributions to resource adequacy. These new market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors for various capacity accreditation resource classes. The groundbreaking proposal was accepted by FERC in May 2022. The capacity accreditation factors will reflect the marginal reliability contribution of the installed capacity suppliers within each capacity accreditation resource class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that begins in May 2024.

[44] NYSRC IRM Study
[45] LCRs

Additionally, every other year, each Regional Entity provides results for NERC's ProbA process; the results from the ProbA performed in 2022 by NPCC appear below.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	6.837	0.091	0.059
EUE (PPM)	0.046	0.001	0.00
LOLH (hours per Year)	0.029	0.00	0.00
Operable On-Peak Margin	11.3%	11.6%	16.7%

* Provides the 2022 ProbA Results for Comparison

NPCC's Directory 1 defines a compliance obligation for NYISO, as Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning period. NYISO delivers a report every year under this study process to verify the system against the one-day-in-ten-years LOLE criterion, usually based on NYISO's latest available reliability assessment results and assumptions. NYSRC Reliability Rules have recently included a requirement that defines NYISO's obligation to deliver a *Long-Term Resource Adequacy Assessment Report* every *Reliability Needs Assessment Report* year and an annual update in the non-RNA years.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the NYCA. The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak will likely shift into the evening as additional BTM solar PV is added to the system and as EV charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the assessment period, BTM solar PV generation becomes less coincident with the NYCA peak hour, and BTM solar PV coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the *Climate Impact Study Phase I* report are included in NYISO's end-use models and are reflected in the baseline, policy scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The ten-year annual average energy (+1.0%) and summer peak demand (+0.5%) growth rates are higher than last year's forecast. Increases in growth rates relative to the prior forecast are primarily attributed to increased large load projects and EV charging impacts, including greater coincidence with periods of peak electricity demand. Baseline energy and coincident peak demand increase significantly throughout the 30-year forecast period, largely by high load project growth in the early forecast years and electrification of space heating, non-weather sensitive appliances, and electric vehicle charging in the outer forecast years. New York is projected to become winter peaking in future decades due to space heating electrification and electric vehicle penetration.

Demand-Side Management

NYISO will develop market concepts to encourage the participation of flexible load; this 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. Many New York utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, and the integration of BTM storage for local peak demand modulation. As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

For the *2023 LTRA Report*, the DR participation for the summer capability period has increased slightly from 1,170 MW to 1,234 MW. There are currently 307 MW of DR participating in ancillary services programs to provide either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO is currently implementing a plan to integrate DERs, including DR resources, into the markets it administers. The DER Participation Model project aims to enhance DER participation in competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, will provide a single participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO is currently developing software associated with these tariff revisions and anticipates deploying its DER participation model in 2023.

Generation

The pace of renewable project development and existing generation retirement is unprecedented and driving a need to increase the pace of transmission, new clean dispatchable generation, and demand management programs development. In general, resource and transmission expansion take many years from development to deployment. Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. Significant new resource development will be required to achieve CLCPA energy targets. The total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply. The sheer scale of resources needed to satisfy system reliability and policy requirements within the next 20 years is unprecedented.

To achieve an emission-free grid, dispatchable emission-free resources (DEFR) must be developed and deployed throughout New York. DEFRs that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. While essential to the grid of the future, such DEFR technologies are not commercially available today.

Essential reliability services usually provided for the system by synchronous fossil generation will continue to be necessary. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities as well as DEFRs will likely be part of this transformation. On May 2023, the New York State Public Service Commission has initiated a process to examine the need for resources to ensure the reliability of the 2040 zero-emissions electric grid mandated by the CLCPA. Under this initiative, the Public Service Commission seeks to identify innovative technologies to ensure reliability of a zero emissions electric grid. Numerous other initiatives at both state and federal levels are in progress and will impact the grid of the future.

Additionally, NYISO's interconnection process contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources; however, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is developing a model for hybrid storage resources to allow multiple technologies at the same point of interconnection participate in the market as a single resource. Additionally, the resource adequacy simulation tools (e.g., GE's MARS) used in system planning and for setting the IRMs were enhanced to include energy limited resources models that allow for charging and discharging and also include temporal constraints (*e.g.,* hours/days or hours/month).

Capacity Transfers

The models used for NYISO reliability planning studies include firm capacity transactions (purchases and sales) with the neighboring systems as a base case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVDC line from Québec into New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model used in the RPP to assess the adequacy of resources employs a number of methods that are aimed at preventing overreliance on the external systems support (e.g., limiting emergency assistance from neighbors by modeling a total limit of 3,500 MW, modeling simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, not modeling emergency operating procedure steps for the neighbors, etc.). As the energy policies in neighboring areas evolve, New York's energy imports and exports could vary significantly due to the resulting changes in neighboring grids. New York is fortunate to have strong interconnections with neighboring areas and has enjoyed reliability and economic benefits from such connections. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. Balancing the need to serve demand reliably while achieving New York's emission-free target will require continuous monitoring and collaboration with neighboring states.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest. Key transmission projects under development and accounted for in the reliability models include the following:

- New York Power Authority/National Grid's Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central NY
- The 1,250 MW Champlain-Hudson Power Express HVDC line from Hydro Québec to New York City
- The AC Public Policy Transmission Projects: upgrading transmission corridors on central NY and lower Hudson Valley (These projects target completion of the majority of the components by December 2023.)

Additionally, there are significant transmission projects either recently selected or under study that are not yet in the reliability model, including the following:

- New York Power Authority/New York Transco project selected by NYISO's Board of Directors to meet the Long Island offshore wind export public policy transmission need.
- PSC recently declared a new Public Policy Transmission Planning Need that is intended to support the integration of 4.7 GW of wind resources in New York City.
- Con Edison's proposed Brooklyn Hub project includes a new 345 kV load serving substation that is reported to potentially serve as a point-of-interconnection for up to 1,500 megawatts (MW) of offshore wind power.

Furthermore, NYISO will also be part of the Transmission Owners' Coordinated Grid Planning Process. The NY Utilities proposal was filed with PSC on December 27, 2022. The PSC initiated a proceeding to develop an integrated planning process that identifies and constructs local transmission and distribution infrastructure solutions in coordination with any necessary bulk transmission infrastructure expansion, throughout New York to support the optimal deployment of investments.

Reliability Issues

The *2022 RNA*, completed in November 2022, identified no reliability needs for the study period 2026–2032. However, NYISO found that the system margins are very narrow in certain locations, such as New York City, for parts of the study period. The 2023 Q2 STAR was completed on July 14, 2023.[46] This assessment finds a reliability need beginning in summer 2025 in New York City that is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City that is affected by the Peaker Rule. The reliability need is a deficiency in the transmission security margin that accounts for expected generator availability, transmission limitations, and updated demand forecasts with data published in the 2023 Gold Book. Specifically, the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions (95 degrees Fahrenheit) when accounting for forecasted economic growth and policy-driven increases in demand. Solutions to this need are being evaluated in accordance with the NYISO Short-Term Reliability Process.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher than expected demand, and extreme weather could threaten reliability and resilience in the future. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such 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 and steep ramping needs. These attributes are critical to a dynamic and reliable future grid. New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway.

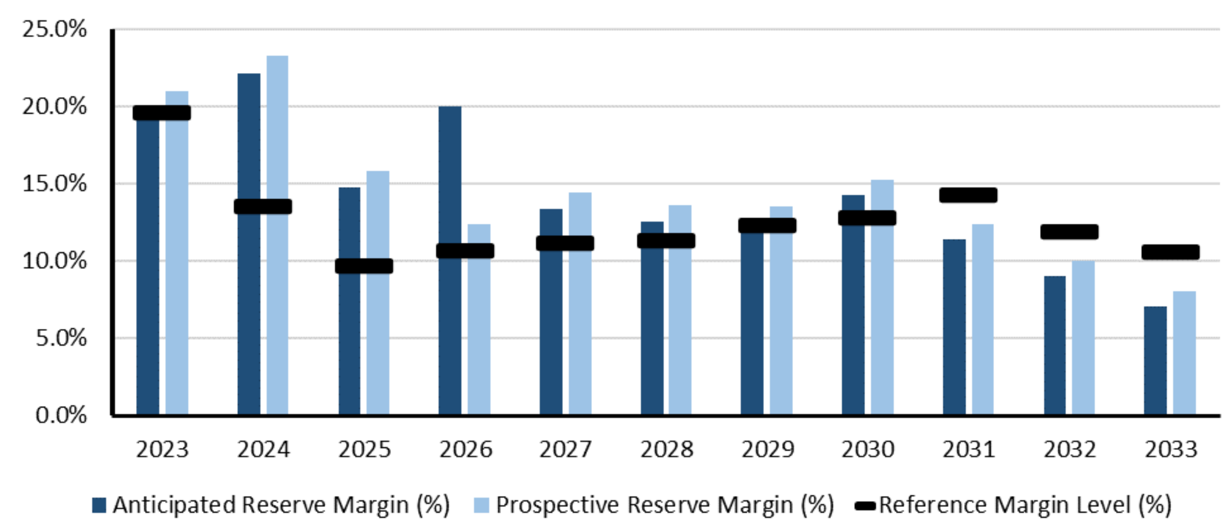
[46] 2023 Q2 STAR Report

NPCC-Ontario

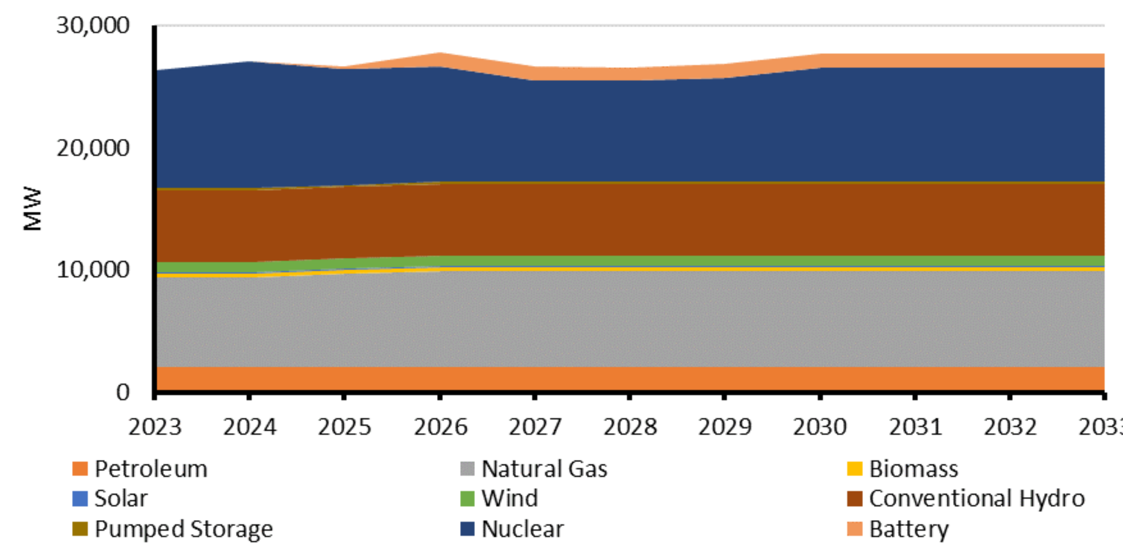
NPCC-Ontario is an assessment area in the Ontario province of Canada. IESO is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	23,236	24,321	24,217	24,460	24,695	24,953	25,295	25,928	25,928	26,387
Demand Response	1,022	544	544	544	544	544	544	544	544	544
Net Internal Demand	22,214	23,777	23,673	23,916	24,151	24,409	24,751	25,384	25,384	25,843
Additions: Tier 1	10	513	1,635	1,635	1,635	1,917	1,917	1,917	1,917	1,917
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	600	600	500	600	600	600	600	0	0
Existing-Certain and Net Firm Transfers	27,124	26,780	26,780	25,487	25,555	25,555	26,364	26,355	25,755	25,755
Anticipated Reserve Margin (%)	22.1%	14.8%	20.0%	13.4%	12.6%	12.6%	14.3%	11.4%	9.0%	7.1%
Prospective Reserve Margin (%)	23.3%	15.8%	12.4%	14.5%	13.6%	13.6%	15.3%	12.4%	10.0%	8.0%
Reference Margin Level (%)	13.5%	9.7%	10.7%	11.2%	11.3%	12.3%	12.8%	14.2%	11.9%	10.6%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The IESO is taking action to secure resources that address reserve margin shortfalls forecast for 2031 that are driven by nuclear retirements, refurbishments, and overall demand growth. The IESO is doing this in part through a mix of long-term contracts for new builds, medium-term contracts for existing resources, and an Annual Capacity Auction. In 2023, the IESO procured new storage resources and upgrades to natural-gas-fired generators and will continue this procurement cycle over the next few years by seeking long-term contracts for both energy and capacity.
- In August 2023, Ontario and Québec signed a memorandum of understanding for the swap of 600 MW of capacity for up to 10 years. Under the proposed electricity trade agreement, the IESO and Hydro-Québec will carry out an annual capacity swap of 600 MW that will help address their respective peak season demands. The agreement is expected to come into effect in winter 2024–2025.
- The IESO is also responsible for implementing new provincial policy as outlined in the Ontario government's *Powering Ontario Growth*, which includes developing new nuclear projects, transmission expansions, and expanded conservation and demand management programs.
- With the recent federal release of draft clean electricity regulations, the IESO is reviewing and will incorporate changes into future planning products, starting with revised supply assumptions in the 2023 Annual Planning Outlook.

NPCC-Ontario Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Petroleum	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107	2,107
Natural Gas	7,337	7,617	7,856	7,856	7,856	7,856	7,856	7,856	7,856	7,856
Biomass	299	299	299	299	299	299	299	299	299	299
Solar	91	91	91	91	91	91	91	91	91	91
Wind	801	801	801	801	801	801	801	801	801	801
Conventional Hydro	5,930	5,930	5,930	5,930	5,930	5,930	5,930	5,930	5,930	5,930
Pumped Storage	118	118	118	118	118	118	118	118	118	118
Nuclear	10,450	9,506	9,506	8,313	8,280	8,562	9,372	9,363	9,363	9,363
Battery	0	223	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107
Total MW	27,133	26,693	27,815	26,622	26,590	26,872	27,681	27,673	27,673	27,673

NPCC-Ontario Assessment

Planning Reserve Margins

ARMs remain adequate for the first seven years of this assessment period. The IESO continues to actively procure resources to meet longer-term needs by using the mechanisms in the Resource Adequacy Framework.

Ongoing refurbishments at Bruce Nuclear Generating Station and Darlington Nuclear Generating Station will see between one and three reactors concurrently off-line through 2033. Refurbishments remain on or ahead of schedule, and outages continue to be managed to limit impacts to the grid. Currently, a request is before the federal nuclear regulator to construct and operate a 300 MW small modular reactor at Darlington by 2028.

The Ontario government has also announced a plan to deliver new small modular reactors and examine new large-scale nuclear generators. The release of *Powering Ontario's Growth* by the provincial government in July 2023 directed the IESO to conduct an impact assessment on potentially adding 4,800 MW of large-scale nuclear capacity to Bruce and three additional 300 MW SMRs at Darlington. While Pickering Nuclear Generation Station is scheduled for decommissioning in 2025, approval is being sought to extend operation through September 2026. The Ministry of Energy has also requested a feasibility assessment on the potential for refurbishing four units at Pickering NGS. The plant operator is conducting a comprehensive technical examination and aims to submit a final recommendation by the end of 2023.

The IESO's *2022 Annual Acquisition Report* identified a need for 4,000 MW of capacity emerging mid-decade, which the IESO is addressing through its Resource Adequacy Framework. The 2022 annual capacity auction secured 1,431 MW of summer and 1,160 MW of winter capacity. The 2022 Medium-Term Request for Proposal (RFP) secured 757 MW of supply from both existing natural gas and wind resources coming off contract; these resources will be available starting 2024–2026. Through long-term procurements, the IESO has acquired 319 MW through on-site natural gas expansions and 930 MW (3,720 MWh) of storage resources. In addition, the IESO has secured 286 MW in natural gas facility upgrades that have had their contracts extended.

Separately, Ontario has entered into an agreement with Oneida Energy Storage for a 250 MW (1,000 MWh) BESS facility expected to be in operation by summer 2026. The IESO has targeted securing 2,500 MW in capacity (1,600 NW storage and 900 MW non-storage) through its long-term RFP with expected commercial operation in 2028.

The IESO calculates the reserve margin requirement on an annual basis and publishes this in the Annual Planning Outlook.[47] The IESO calculates the reserve margin requirement for each year for net demand at the time of the annual demand peak to provide an LOLE that is at or below 0.1 days per year. The reserve margin requirement in the 2023 LTRA is derived from the capacity requirement in the 2022 *Annual Planning Outlook*[48]

Energy Assessment and Non-Peak Hour Risk

Energy adequacy assessments are conducted annually for the annual planning outlook by using a deterministic approach in the IESO's economic dispatch model. Should Pickering Nuclear Generating Station retire 2024–2025, increased adequacy risks are expected; however, an extension to 2026 would help alleviate these risks until 2027, when unserved energy is forecast to be 1.09 TWh.

The IESO now assesses capacity adequacy accounting for both peak and non-peak load hours to form a more comprehensive assessment. Generally, summer hours represent the highest probability of load loss, but actual hourly profiles change yearly. The IESO's first round of long-term procurements is securing resources that can provide energy at least four hours at a time.

Looking forward, the federal government has proposed Clean Energy Regulations to decarbonize Canada's electric system by 2035. The IESO is assessing the current role of natural gas generation as a flexible resource in the interim as it introduces new sources of non-emitting supply to the system.

Future annual planning outlooks will continue to highlight deficits in capacity and energy as Ontario works toward decarbonization targets and procurements with the regular cadence outlined in the Resource Adequacy Framework.

Probabilistic Assessments

No probabilistic assessment has been performed since 2022 but will occur later this year by both the IESO and NPCC. However, risks will have decreased compared with 2022 due to procurements, nuclear units being extended, and refurbishments coming in on time or ahead of schedule.

[47] Planning and Forecasting Annual Planning Outlook
[48] 2022 Annual Planning Outlook Data Tables

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	0.049	0.00	72.164
EUE (PPM)	0.00	0.00	0.492
LOLH (hours per Year)	0.001	0.00	0.442
Operable On-Peak Margin	4.4%	7.9%	-6.7%

* Provides the 2020 ProbA Results for Comparison

Demand

Forecasted demand over the 10-year study period increased by 5% and 10% in summer and winter, respectively, after the preliminary LTRA data submission. Increased demand for electricity is being driven by population growth, economic expansion, and increased penetration of electric devices. Offsetting this growth are conservation, electricity price responsiveness, and increased output by embedded generation. Overall, demand is ramping up more quickly than in 2022 due to government policy on decarbonization. Notable increases in demand arise from growth in the greenhouse sector, use of industrial electric arc furnaces, EVs, BESS manufacturing operations, and new mines.

Ontario continues to be summer peaking through the forecast period. The IESO's Industrial Conservation Initiative acts as a critical peak-pricing program and is expected to reduce around 1,300 MW on the system peak hour of the top five system peak days and 650 MW on the second top-five days (days 6-10). It is expected to scale based on increased industrial growth in future years. Over this assessment period, the IESO projects the total internal demand growth to increase at a CAGR of 1.42% for summer and 1.59% for winter.

Demand-Side Management

Capacity auction resources consist mainly of DR followed by generation and imports. Beginning this year, the IESO is introducing a qualification process that will apply resource-specific methodologies to determine the unforced capacity for each resource is able to offer into the auction.

In 2023, the IESO implemented new programs designed to grow Ontario's DR capability, particularly during the peak summer months. The Peak Perks program is targeted at residential customers while a new industrial pilot is designed to identify events in advance that large load customers can respond to effectively to reduce their exposure to capacity charges.

The 2021–2024 Conservation and Demand Management Framework managed by the IESO continues with increased budget and additional savings. Incremental savings are included in the overall demand forecast but remain in line with 2021–2024 levels. An EE auction pilot secured peak demand reductions of 7.4 MW for winter 2022–2023 and 6.6 MW for summer 2023. Typically, EE measures persist for years.

Distributed Energy Resources

The IESO estimates that contracted DERs contributed more than 3,400 MW of capacity and 5.3 TWh of energy in 2022, more than half of which is solar PV, one-third wind and modest contributions from hydroelectric and biomass resources. While IESO has little insight into uncontracted DERs, it has observed energy contributions of approximately 2 TWh in 2022.

Generation

Recent generation procurements are provided in the Planning Reserve Margin section.

IESO has initiated implementation of new technologies, processes, and more dynamic tools to support the operation of the transforming grid with more diverse resource types and a more complex transmission system.

The IESO's 2022 *Pathways to Decarbonization* report included a limited assessment of the ability of Ontario's resource portfolios to manage a variety of conditions in real time. Further areas to explore include the sufficiency of the studies' resource mix to provide inertia and primary frequency response, operating reserve, ramping capability and reactive support, and voltage control. The IESO is also investigating implications of increased penetration of variable resources on the system.

The IESO-controlled grid will have sufficient system inertia and frequency response to ensure stable operation up to 2025. The IESO worked with the provincial regulator to amend the Distribution System Code, which was released in 2022 to include the requirements of the new IEEE 1547-2018 standard. This effort was to ensure all resources contribute, as needed, to maintain grid reliability. The IESO also acts in accordance with NERC Reliability Standards to ensure adequate warning is provided for generators coming off-contract that would adversely impact grid reliability. In such scenarios, Reliability-Must-Run contracts can be established to meet system needs.

Energy Storage

Recent storage procurements are provided in the Planning Reserve Margin section. Currently, storage resources in Ontario amount to only about 50 MW, excluding the Beck generating stations' overall capacity. Some storage provides capacity while the rest offer ancillary services. The Expedited Long-Term RFP procured 930 MW of storage for a commercial operation start date of May 1, 2026. The LT1 RFP process has targeted 1,600 MW of storage with a commercial operation date of May 1, 2028. Both procurements required storage resources to have a minimum four-hour duration.

Prevalent uses for existing storage include regulation services, reactive support and voltage control, energy market participation, and BTM peak shaving. Newly acquired energy storage facilities will be required to participate in Ontario's energy markets during peak hours. Non-committed storage is now able to participate in the annual capacity auctions and provide capacity and operating reserve. Market integration of hybrid storage-generation resources has been identified as a priority under the umbrella of projects within the enabling resources initiative, and stakeholder engagement is underway.

Capacity Transfers and External Assistance

Firm capacity imports and exports with neighboring jurisdictions are included in the IESO's planning studies, but the IESO assumes only a limited amount of imports for the purposes of its reliability assessments. The IESO also includes non-firm imports of 250 MW for summer and 240 MW for winter.

Although Ontario has been a net energy exporter for many years, exports are expected to decrease sharply with the retirement of Pickering Nuclear Generating Station and more units on outage. The area's most recent energy adequacy assessments suggest economic imports will increase, and Ontario could become a net energy importer throughout the refurbishment period.

As part of the capacity exchange agreement between Ontario and Québec, the IESO may call on a total of 500 MW of firm imports from Hydro-Québec over summer months prior to September 2030. The decision on when to call the capacity will be made in due course depending on the outcomes of the IESO's current procurement and the potential extension to Pickering Nuclear Generating Station operations.

Transmission

March 31, 2022, marked the in-service date for the expansion of the East–West Tie with the addition of a 230 kV double-circuit transmission line to provide the necessary transfer capability to meet capacity needs in the IESO's northwest area.

The IESO is reinforcing its bulk system in the province's Northeast with the development of three new transmission lines to support electrification of the steel industry as well as overall growth in the area.

A new double-circuit 230 kV transmission line from Chatham Transmission Station (TS) to Lakeshore TS will bring additional supply to the Windsor-Essex area and is expected to be completed by Q4 2025. It will also improve the ability for resources and bulk facilities to operate efficiently and maintain the existing interchange capability on the interconnection between Windsor and Detroit, Michigan. The IESO has recommended further reinforcement to support the area's medium-term needs, including an additional double-circuit 230 kV line from Lambton TS to Chatham TS, expected in-service by 2028, and a new 500 kV transmission line from Longwood TS to Lakeshore TS to be in service by 2030.

To reinforce the Peterborough area, the IESO is developing a new double-circuit 230 kV transmission line with a planned in-service date of 2029. In addition to these new lines, additional refurbishment and upgrade projects are planned across the province to maintain reliability.

Reliability Issues

Nuclear refurbishment over the next decade is a major resource risk that requires additional attention. The IESO has regular meetings with nuclear operators to assess probable delays and take appropriate mitigation actions.

For long-term planning purposes, the IESO carries an additional level of reserve to account for these risks. It provides advanced outage approvals solely when Ontario is adequate under extreme weather. Ontario's reserves were below reserve margin requirements during most of summer 2023 due to planned generator outages, including nuclear, but the IESO managed this by either rejecting planned outages during this time if extreme weather materialized or used emergency control actions.

Other factors that may contribute to IESO reliability issues include supply chain issues, conditions in neighboring jurisdictions, extreme weather, decarbonization-driven changes to supply and demand, policy and regulatory uncertainty, asset health, forced outages, and potential market exit.

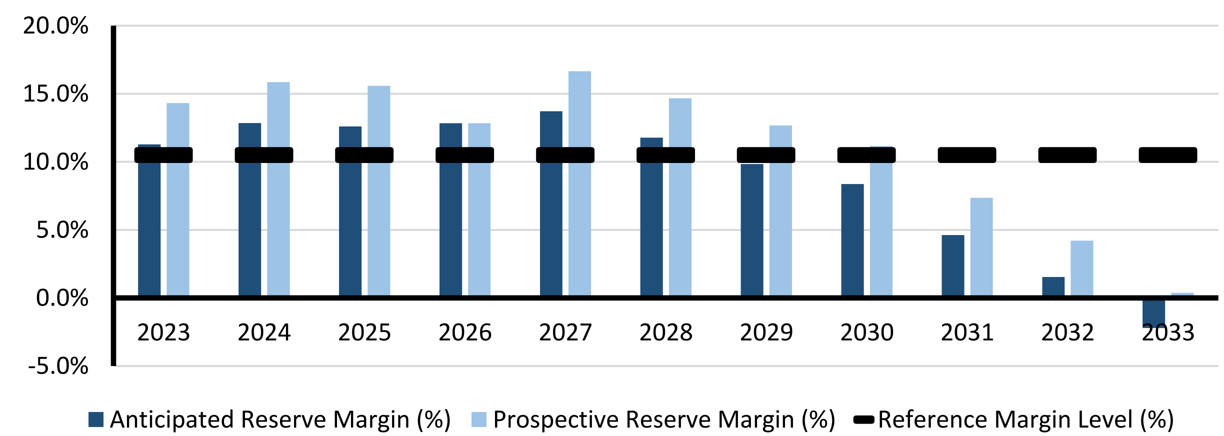
The IESO has not conducted specific assessments on critical infrastructure but does monitor performance of its natural gas facilities. More than 18% of natural-gas-fired generation has dual-fuel capability with on-site oil supply in winter for more than a day of operation. In the *2022 Annual Planning Outlook's* 20-year planning period, the risk for pipeline contingencies is low when calculating reserve margin. While the diverse supply mix helps improve resilience, the IESO will continue to monitor natural gas supply as demand leads to increased dependence on this resource, including for significant energy.

NPCC-Québec

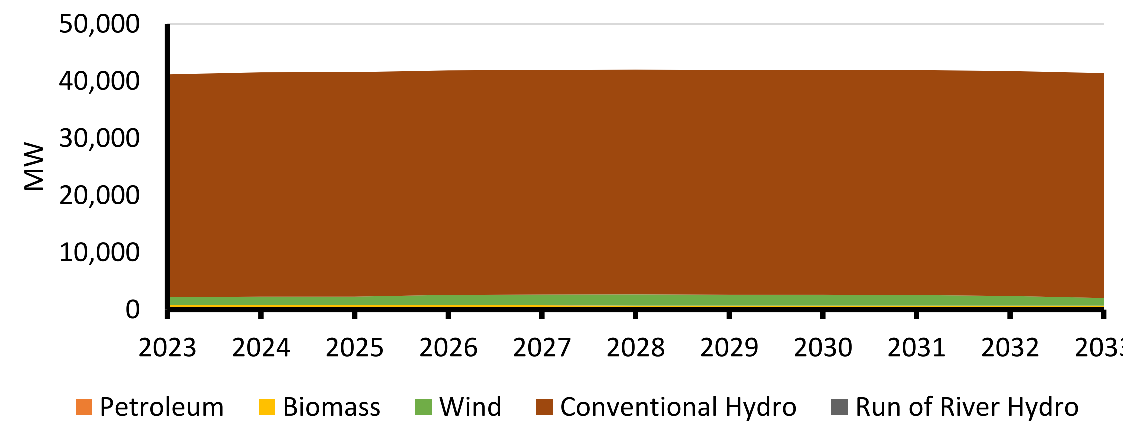
The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight and a half million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVDC ties, radial generation, or load to and from neighboring systems. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins[49]

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	41,036	41,488	41,946	42,468	43,377	44,062	44,776	45,569	46,627	47,820
Demand Response	4,452	4,732	4,896	5,068	5,258	5,322	5,377	5,389	5,389	5,389
Net Internal Demand	36,584	36,756	37,049	37,400	38,118	38,740	39,399	40,181	41,238	42,432
Additions: Tier 1	73	73	559	687	815	815	815	815	815	815
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	-334	-245	-145	455	455	455	600	0	0	0
Existing-Certain and Net Firm Transfers	41,211	41,312	41,246	41,840	41,793	41,734	41,882	41,222	41,060	40,677
Anticipated Reserve Margin (%)	12.8%	12.6%	12.8%	13.7%	11.8%	9.8%	8.4%	4.6%	1.5%	-2.2%
Prospective Reserve Margin (%)	15.9%	15.6%	12.8%	16.7%	14.7%	12.7%	11.2%	7.4%	4.2%	0.4%
Reference Margin Level (%)	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%



Planning Reserve Margins



Existing and Tier 1 Resources

[49] The electric system in NPCC-Quebec

Highlights

- The ARM remains above the RML until 2029. However, the PRM is above the RML until 2031.
- Approximately 877 MW of capacity additions are expected over this assessment period. A total of 2,548 MW wind generation capacity (815 MW capacity value at peak time) is expected to be in service by 2029.
- The commissioning of the second Micoua-Saguenay 735 kV line is expected by the end of 2023.

NPCC- Québec Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Petroleum	429	429	429	429	429	429	429	429	429	429
Biomass	378	378	397	397	345	281	277	277	277	269
Solar	10	10	10	10	10	10	10	10	10	10
Wind	1,375	1,449	1,449	1,751	1,843	1,936	1,893	1,893	1,842	1,678
Conventional Hydro	38,975	39,269	39,275	39,280	39,317	39,354	39,354	39,354	39,362	39,362
Total MW	41,166	41,533	41,558	41,866	41,942	42,008	41,962	41,962	41,919	41,748

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 RML over this study period assessment except for the last five winter periods 2030–2034. However, the PRM remains above the RML for almost all years of this assessment. Under the Prospective scenario, a total of 1,100 MW of expected capacity supply is planned by the Québec area; 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 Québec area proceeds with short-term capacity contracts to meet its capacity requirements.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	7.1%	-1.6%	-2.3%

* Provides the 2020 ProbA Results for Comparison

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 Québec area demand forecast average annual growth is 1.2% during this assessment period.

Demand-Side Management

The 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 2,790 MW on winter 2023–2024 peak demand. The area is also expanding its existing interruptible load program for commercial buildings that will grow from 568 MW in 2023–2024 to 889 MW by the end of this assessment period. Another similar program for residential customers is in operation and should gradually rise from 96 MW for winter 2023–2024 to 621 MW for winter 2028–2029 and continue to grow in later years.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 297 MW for winter 2023–2024and 445 MW for winter 2033–2034.

Moreover, data centers specialized in blockchain applications are required to reduce their demand during peak hours at Hydro-Québec's request. Their contribution as a resource is expected to be around 269 MW over this assessment period.

Finally, another DR resource consists in a voltage reduction scheme allowing 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 718 MW in 2034. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter-peaking area, solar PV on-peak contribution ranges from 1 MW for winter 2023–2024 to 5 MW for winter 2033–2034.

Generation

Four wind generation projects are expected to be in service during this assessment period for a total of 2,548 MW of installed capacity (815 MW on-peak value). The first project, Apuiat (204 MW), is expected to be in service in 2024–2025. The second project, Des neiges (1,200 MW), is divided into three phases. The first phase (400 MW) is expected to be in service for the 2026–2027 winter period. The second and third phase with the same capacity (400 MW each) are expected to be in service for the 2027–2028 and 2028–2029 winter periods, respectively. The third and last project is the 2021 call for tenders for a total of 1,144 MW of wind, and it is expected to be in service in December 2026.

The integration of small hydro unit accounts for 41 MW new capacity during this assessment period.

Capacity Transfers and External Assistance

The governments of Québec and Ontario have signed a Memorandum of Understanding (MOU) of an Agreement that allows a seasonal capacity exchange between the two areas for the next seven years except for the year 2027 (no exchange is allowed). The technical details of the Agreement will be completed by the next Fall (2024). The agreement will start from winter 2024–2025 to winter 2030–2031. This agreement will be firm and allow the Québec area to import 600 MW from November to April. In the summer season, Québec will export 600 MW of firm capacity to Ontario from May to October.

Transmission

- **The Micoua-Saguenay 735-kV Line**
  Hydro-Québec has identified the need to build a new 735 kV line that extends 262 km (163 miles) between Micoua substation in the Côte-Nord region 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 and is expected to be in service in 2023.

- **Appalaches-Maine Interconnection**
  This project to increase transfer capability between Québec and Maine by 1,200 MW is in the construction phase. The project will connect to the New England Clean Energy Connect project in Maine. It involves the construction of a ±320-kV DC transmission line about 100 km (62 miles) long from Des Appalaches 735/230-kV substation to the Canada–United States border. From the international border crossing, the dc transmission line will be extended 145 miles to a substation in Lewinston, ME, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at Des Appalaches substation and triggers the need of thermally upgrading two 735 kV lines in the south of the system. The first thermal upgrade was completed in 2022 and the second one is expected to be completed in 2023. The planned in-service date of the interconnection project is under review.

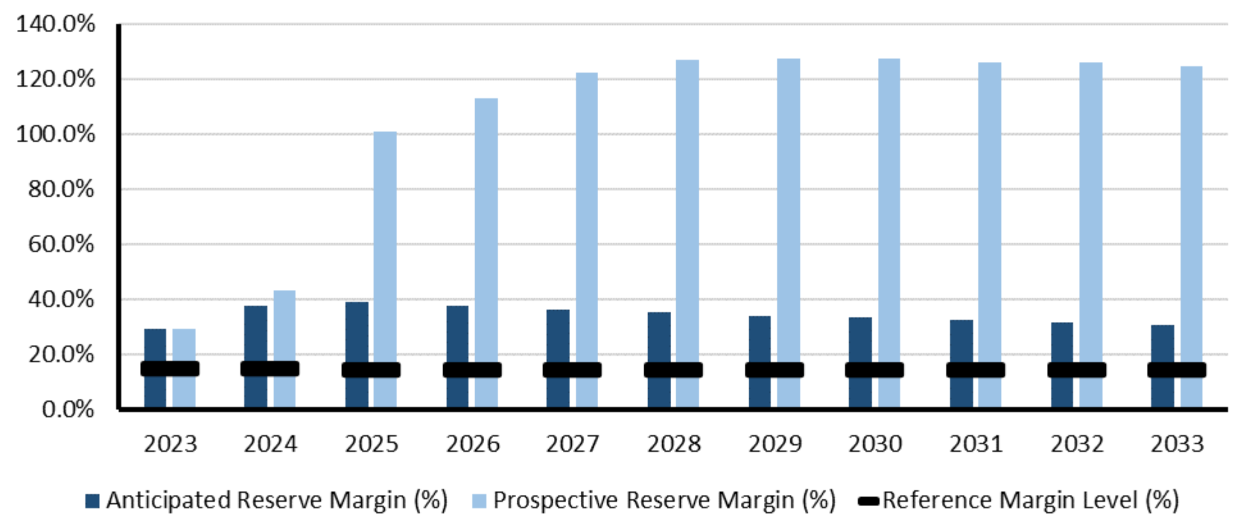
- **Hertel-New York Interconnection**
  This project to increase transfer capability between Québec and New York by 1,250 MW is currently in the permitting phase. It involves the construction of a ±400 kV DC underground transmission line about 60 km (37 miles) long from Hertel 735/315 kV substation just south of Montréal to the Canada–United States border. The project will connect to the Champlain Hudson Power Express project in New York State. From the international border crossing, the dc transmission line will be extended 339 miles to a substation in Astoria, NY, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at Hertel substation. The project is expected to be in service in May 2026.

PJM

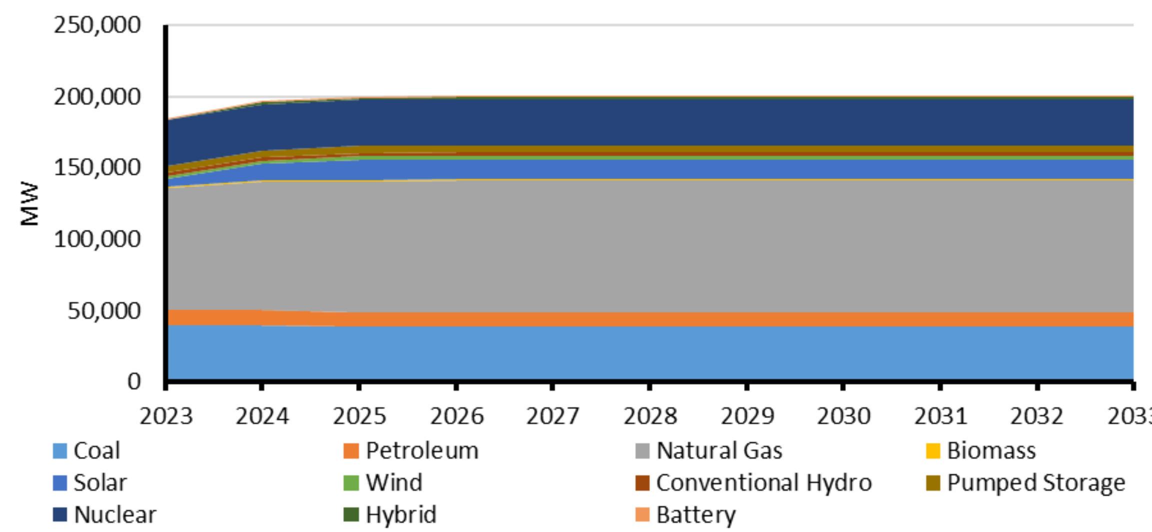
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. 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. See **Normal Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	149,737	150,924	152,736	154,275	155,703	156,923	157,899	158,942	159,917	160,971
Demand Response	7,397	7,453	7,515	7,573	7,617	7,646	7,679	7,710	7,731	7,758
Net Internal Demand	142,340	143,471	145,221	146,702	148,086	149,277	150,220	151,232	152,186	153,213
Additions: Tier 1	13,090	18,234	19,715	19,706	19,706	19,706	19,706	19,706	19,706	19,706
Additions: Tier 2	7,982	88,414	109,210	126,252	135,888	139,177	141,681	141,855	144,220	144,220
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-607	-105	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	181,614	180,346	179,338	179,324	179,324	179,324	179,324	179,324	179,324	179,324
Anticipated Reserve Margin (%)	36.8%	38.4%	37.1%	35.7%	34.4%	33.3%	32.5%	31.6%	30.8%	29.9%
Prospective Reserve Margin (%)	42.4%	100.0%	112.2%	121.7%	126.1%	126.5%	126.7%	125.3%	125.5%	124.0%
Reference Margin Level (%)	14.8%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%	14.7%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM is above the RML for each year of the assessment period.
- As in other assessment areas, there is potential for resource adequacy risks to emerge in PJM during the later years of the assessment period and beyond. In February 2023, PJM published a report of its analysis of the future energy transition in PJM based on resource retirement, replacement, and electricity demand scenarios.[50] PJM found increasing reliability risks due to the potential for the timing of generator retirements to be misaligned with load growth and the arrival of new generation on the system. Trends toward higher demand, faster generator retirements, and slower resource entry could expose PJM to decreasing Planning Reserve Margins and reliability challenges from imbalanced resource composition and resource performance characteristics. Unlike the demand forecasts and resource projections in this LTRA, the PJM report used scenarios and modeling for its analysis.

PJM Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	39,921	38,648	38,238	38,238	38,238	38,238	38,238	38,238	38,238	38,238
Petroleum	10,206	10,039	10,039	10,039	10,039	10,039	10,039	10,039	10,039	10,039
Natural Gas	89,804	91,820	93,310	93,310	93,310	93,310	93,310	93,310	93,310	93,310
Biomass	928	931	930	930	930	930	930	930	930	930
Solar	11,802	14,135	13,402	13,386	13,386	13,386	13,386	13,386	13,386	13,386
Wind	1,963	2,527	2,605	2,601	2,601	2,601	2,601	2,601	2,601	2,601
Conventional Hydro	2,523	2,439	2,429	2,426	2,426	2,426	2,426	2,426	2,426	2,426
Pumped Storage	4,798	4,801	4,786	4,786	4,786	4,786	4,786	4,786	4,786	4,786
Nuclear	32,594	32,594	32,594	32,594	32,594	32,594	32,594	32,594	32,594	32,594
Hybrid	1,212	1,035	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006
Battery	836	992	990	990	990	990	990	990	990	990
Total MW	196,587	199,960	200,329	200,305	200,305	200,305	200,305	200,305	200,305	200,305

[50] Energy Transition in PJM: Resource Retirements, Replacements, and Risks

PJM Assessment

Planning Reserve Margins

The ARM for each year in this assessment period does not fall below the RML in PJM. PJM has a normal risk of energy shortages.

Energy Assessment and Non-Peak Hour Risk

PJM is expecting a normal risk of experiencing periods of resources falling below required operating reserves during upcoming peak periods based on the *2022 PJM Reserve Requirement Study*. As indicated in the *2022 PJM Reserve Requirement Study*, PJM is forecasting around 30% installed reserves (including expected committed demand resources), which is well above the target IRM of 14.9% necessary to meet the 1-day-in-10-years LOLE criterion. Due to the relatively 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. Notwithstanding the above, to address potential future reliability concerns due to limitations associated with the performance of limited and variable resources, PJM's ELCC methodology calculates the reliability and energy contribution of limited and variable resources.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	29.0%	29.0%	28.0%

* Provides the 2020 ProbA Results for Comparison

Demand

The PJM Interconnection produces an independent peak load forecast of total internal demand by using econometric regression models with daily load as the dependent variable and independent variables including calendar effects, weather, economics, and end-use characteristics. PJM annually reviews 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.

Demand-Side Management

DR resources can participate in all PJM Markets–capacity, energy, and ancillary services.

Distributed Energy Resources

PJM expects 4,865 MW of solar PV DER at the time of the peak in 2028 and 7,109 MW in 2033. The effects of solar PV DER are included in the load forecast for PJM. No effect of solar PV DER is incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation

PJM's existing installed capacity reflects a fuel mix that is comprised of approximately 47% natural gas, 24% coal, and 18% nuclear. Hydro, wind, solar PV, 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 78,000 MW of Capacity Interconnection Rights (CIRs), renewable fuels are changing the landscape of PJM's interconnection queue. Solar PV energy comprises 66% of the generation in PJM's interconnection queue, a 10% increase over the previous year. An increase in solar PV generation interconnection requests is attributable to state policies encouraging renewable generation.

Prior to 2021, the 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 ELCC method. This more robust methodology recognizes the full value of a resource's output over high-load risk hours and also accounts for resources by using an ELCC methodology 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 intermittent, limited-duration and hybrid resources beginning with the 2023/2024 delivery year.

Energy Storage

Energy storage development continues to grow in PJM. As solar PV generation increases across the PJM footprint, storage growth is expected to follow, particularly as part of co-located projects. Efficient grid operations in an era of rapid renewable energy resource growth will require increased electric system flexibility. Energy storage can help grid operators maintain stable power supply under varying wind and solar power output that is driven by weather conditions and unit outages and improve utilization levels of existing transmission facilities. PJM has worked with various companies and national laboratories to study storage use and to ensure that the PJM wholesale market can permit all forms of energy storage to participate. PJM recognizes that storage paired with renewables and transmission can optimize the delivery of power. To address the limited-duration issue, some developers are pairing storage with variable renewable generation, such as solar PV or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or is hybrid (in which the storage facility and generator share a common connection to the grid).

Today, storage resources are made up of pumped storage hydro for a total of nearly 4,000 MW as well as BESS and flywheel energy storage for a total of 300 MW. Pumped storage can participate in the PJM capacity, energy, regulation and reserves markets. Queued storage resources total over 34,000 MW of interconnection requests for CIRs.

Capacity Transfers and External Assistance

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if transfers were dropped to zero.

Transmission

The $2.4 billion of baseline transmission investment approved during 2022 continues to reflect the shifting dynamics driving transmission expansion. New large-scale transmission projects (345 kV and above) have become more uncommon as RTO load growth has fallen below 1%. Aging infrastructure, grid resilience, a shifting generation mix, and more localized reliability needs are now more frequently driving new system enhancements.

Reliability Issues

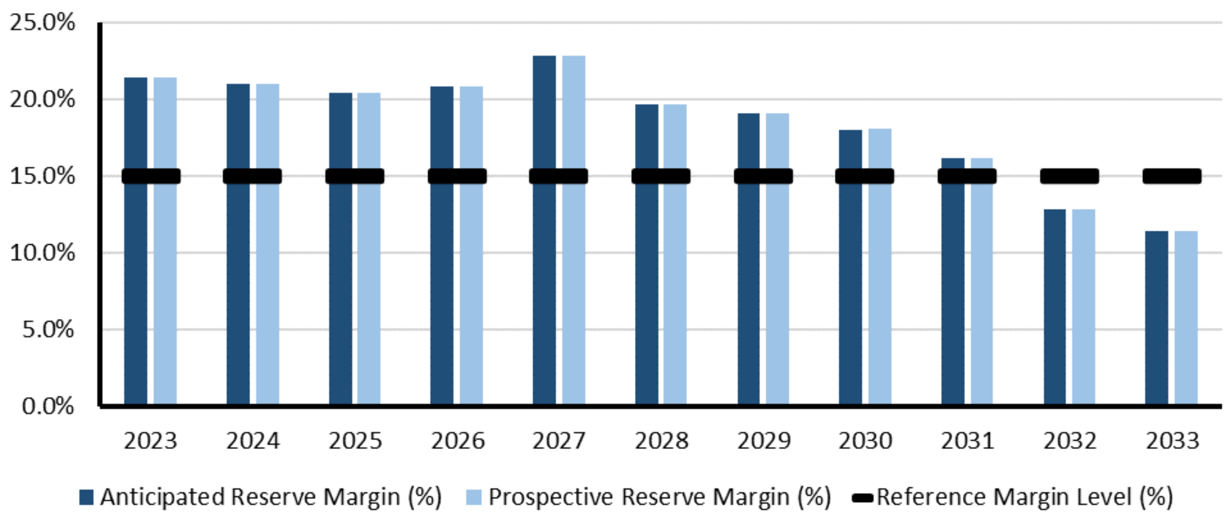
Offshore wind is emerging as a potential major source of power that is seeking grid interconnection along coastal states in the PJM area. Through September 2021, only two operational offshore wind farms in the United States have reached commercial operation: the 30 MW Block Island Wind Farm off the coast of Rhode Island and the 12 MW Coastal Virginia Offshore Wind Pilot Project near Virginia Beach. Although current operational capacity totals are low, offshore wind is expected to be a major contributor to U.S. clean energy and decarbonization initiatives over the coming decades.

SERC-East

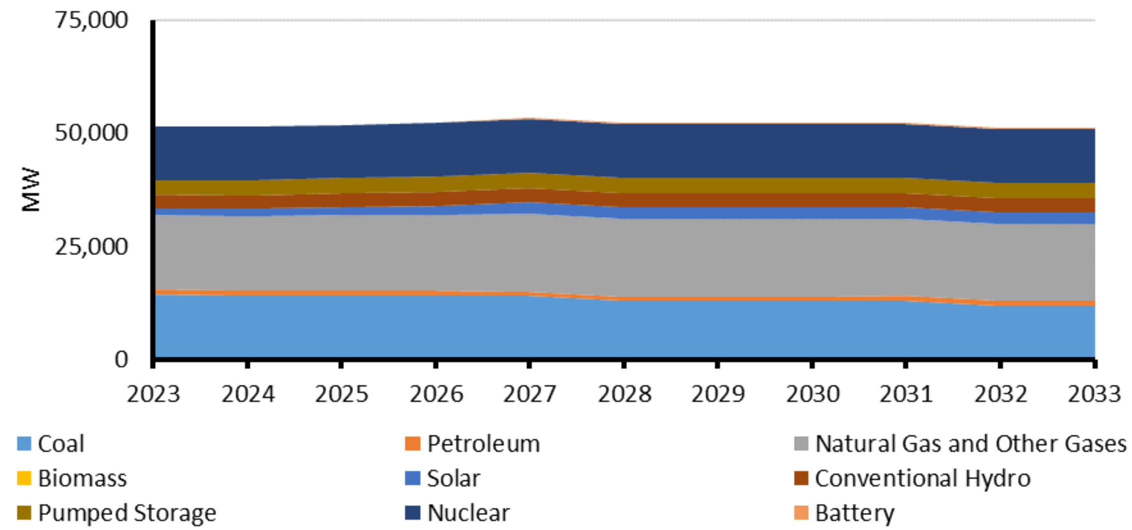
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 PAs, and 7 RCs. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	44,014	44,590	44,789	44,993	45,220	45,425	45,831	46,583	46,985	47,580
Demand Response	983	989	996	1,003	1,006	1,007	1,008	1,009	1,010	1,011
Net Internal Demand	43,031	43,601	43,793	43,990	44,214	44,418	44,823	45,574	45,975	46,569
Additions: Tier 1	55	546	961	2,267	2,267	2,267	2,267	2,267	2,267	2,267
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	624	624	624	624	624	624	624	624	624	624
Existing-Certain and Net Firm Transfers	52,290	51,954	51,954	51,778	50,648	50,648	50,648	50,667	49,620	49,620
Anticipated Reserve Margin (%)	21.6%	20.4%	20.8%	22.9%	19.7%	19.1%	18.1%	16.1%	12.9%	11.4%
Prospective Reserve Margin (%)	21.6%	20.4%	20.8%	22.9%	19.7%	19.1%	18.1%	16.2%	12.9%	11.4%
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

Highlights

- ARMs are above the RML through 2031.
- Natural gas (32%), coal (28%), and nuclear (23%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types make up the remaining (17%) generation.
- From 2023 to 2033, SERC-East will retire nearly 2.6 GW of coal generation. Tier 1 addition of 0.7 GW natural gas, 1 GW of BES-connected solar PV, and 0.4 GW BESS is expected during this time. At this time, 24 MW of utility-scale transmission BES-connected BESS. 350 MW of Tier 1 nameplate capacity BESS is expected within 10 years.
- Historically a summer peaking area, SERC-East is forecasting higher peak demands during winter months.
- The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area is expected to grow annually at a rate of approximately 0.8% on average in the next 10 years.

SERC-East Generation Capacity by Fuel Type (Summer)										
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Coal	14,426	14,005	14,005	14,005	12,875	12,875	12,875	12,875	11,828	11,828
Petroleum	1,174	1,174	1,174	1,122	1,122	1,122	1,122	1,141	1,141	1,141
Natural Gas	16,227	16,718	16,718	16,970	16,970	16,970	16,970	16,970	16,970	16,970
Biomass	173	173	173	173	173	173	173	173	173	173
Solar	1,528	1,528	1,943	2,523	2,523	2,523	2,523	2,523	2,523	2,523
Conventional Hydro	3,030	3,115	3,115	3,115	3,115	3,115	3,115	3,115	3,115	3,115
Pumped Storage	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364	3,364
Nuclear	11,789	11,789	11,789	11,789	11,789	11,789	11,789	11,789	11,789	11,789
Battery	11	11	11	361	361	361	361	361	361	361
Total MW	51,721	51,876	52,291	53,421	52,291	52,291	52,291	52,310	51,263	51,263

SERC-East Assessment

Planning Reserve Margins

SERC-East ARMs are above the RML during the first nine years of this assessment period.

Energy Assessment and Non-Peak Hour Risk

Entities are developing ways of evaluating energy risk and rely on production cost modeling to evaluate energy adequacy. Entities continue to identify generation resource constraints in operations planning. Some are developing probabilistic techniques to incorporate more variation of inputs, such as load, force outage rate, and renewable energy generation. The assessment area did not identify increased energy risks during the non-peak hours. However, ramping needs are increasing with the additional solar PV generation penetration.

Probabilistic Assessments

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	5.26	64.33	92.49
EUE (PPM)	0.024	0.272	0.389
LOLH (hours per Year)	0.01	0.06	0.081
Operable On-Peak Margin	15.9%	15.0%	16.1%

* Provides the 2022 ProbA Results for Comparison

SERC-East is peaking during winter months. This is due to the addition of solar PV generation that shaves off summer peak demand and the observed trend toward electrification of heating that drives up winter peak demand. The reliability risk as indicated by the 2022 ProbA is projected to be stable. Higher winter peaks and/or lower supply of capacity during the early winter morning demand contributed to the increase in EUE metric values. The severe cold weather stress-test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages. The severe cold weather stress-test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand

Historically a summer peaking area, SERC-East is forecasting higher peak demands during winter months. The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 0.8% on average in the next 10 years.

Demand-Side Management

Entities use demand-side management programs to reduce load on the system during times of high peak demand. Seasonal load reduction capabilities for each individual participant are aggregated to determine the estimated program capacities that are available as dispatchable grid reliability resources. Program capacities are continually updated based upon changes in enrollment levels or application of newly acquired peak period data. A continued focus going forward for growth of existing programs and introduction of new programs is on maximizing winter capabilities. Heat strip load control programs can be used for mechanical winter peak reduction for customers. Though they are dependent on the thermostat manufacturer notification and usage rules, they provide the greatest benefit in terms of reduction with minimal customer discomfort. “Bring Your Own kW” programs allow small and medium business participants to compensate for load reduction through any methods they can employ. Electric vehicle managed charging is also being tested in the Carolinas. Other technologies to watch in the short term are Wi-Fi enabled water heaters and BTM storage. Further into the future, smart panels and smart inverters may provide value. Efforts to control voltage are also increasing.

Distributed Energy Resources

The DER resources are mainly solar PV projects. Entities include all future DER resources in their models which have a signed Interconnection Agreement. Any network upgrades associated with those projects are also included in the models. Entities study more light-load scenarios when solar PV resources will be near maximum and a large percentage of system load to reveal any possible transmission issues in that dispatch scenario. The DER forecasts are developed using economic models of payback, which is a function of installed cost, regulatory incentives and statutes, and bill savings. A relationship between payback and customer adoptions is developed through regression modeling, and the resulting regression equations are used to predict future customer adoptions based on projected payback curves. Customer size estimates based on historical adoption data are used to convert the future customer adoptions to capacity and hourly profiles are employed to yield the generation projections. The projected hourly generation from the DER forecasts is incorporated into the load forecasts as a load modifier, thus reducing the expected future load. As the BESS continue to grow, the DER forecasts will be enhanced to include separate projections of BTM solar PV only and BTM solar PV plus storage systems.

Generation

Natural gas (32%), coal (28%), and nuclear (23%) generation are the dominant fuel types within the SERC-East assessment area. Hydro, renewables, and other fuel types make up the remaining (17%) generation. SERC-East assessment area will retire nearly 2.6 GW of coal generation within the next 10 years. Tier 1 addition of 0.7 GW natural gas, 1 GW BES-connected solar PV, and 0.4 GW BESS is expected during this time.

Energy Storage

There is 11 MW of utility-scale transmission BES-connected BESS at this time. 350 MW of Tier 1 BESS is expected within 10 years.

Capacity Transfers and External Assistance

During high demand periods and the simultaneous unavailability of a severe and significant portion of generation, capacity transfer may be limited. Limited coal availability at coal plants located in specific areas of the system could also limit transfer capability. Entities will evaluate transmission projects and coordinate with neighboring TOPs/RCs to manage the interfaces and take needed actions such as generation redispatch, transmission reconfiguration, and TLRs.

Transmission

The assessment area will add another 46.7 miles within the first five years, followed by 0.3 mile in the next five years of new AC transmission lines with the voltage range between 100 to 200 kV. The assessment area will add another 173.6 miles within the first five years, followed by 43.1 miles in the next five years of new AC transmission lines with the voltage range between 200 to 300 kV. These projects are in the planning/construction phase and are projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability.

Reliability Issues

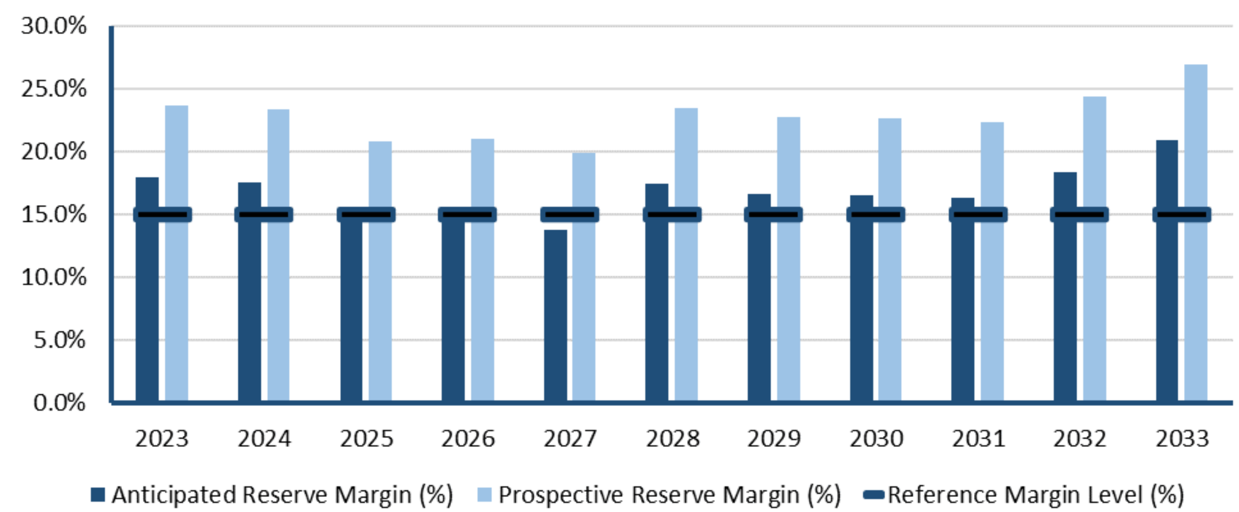
Extreme cold and hot weather preparation with guidance on actions related to forecasted periods of grid stress through risk assessments is an area of focus for this assessment area. One entity reported that it removed natural gas infrastructure from its transmission load shedding plan and coordinates with its natural gas transportation providers in its area to place the appropriate priority on electricity service to any critical natural gas infrastructure. Sensitivity analyses help the entities prepare for changes in generation mix and develop projects to improve future system conditions, and/or operational guidelines to mitigate any observed risks.

SERC-Central

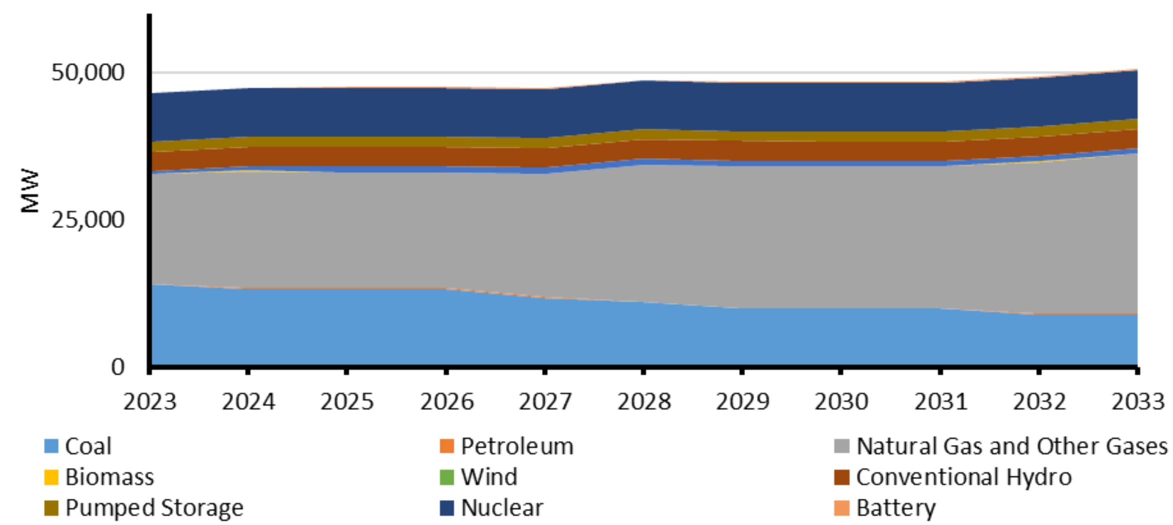
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC) approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 Planning Authorities (PA), and 7 RCs. See High Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	42,259	42,595	42,560	42,737	42,739	42,765	42,764	42,858	42,877	43,109
Demand Response	1,851	1,835	1,838	1,842	1,840	1,839	1,837	1,836	1,835	1,834
Net Internal Demand	40,408	40,760	40,722	40,895	40,899	40,926	40,927	41,022	41,042	41,275
Additions: Tier 1	1,600	2,526	2,530	3,876	6,086	6,934	6,934	6,934	8,755	10,081
Additions: Tier 2	20	170	170	170	170	170	170	170	170	170
Additions: Tier 3	28	235	463	1,015	1,568	2,170	2,623	3,075	3,528	3,980
Net Firm Capacity Transfers	198	-677	-677	-677	-677	-677	-677	-677	-677	-677
Existing-Certain and Net Firm Transfers	45,922	44,247	44,247	42,673	41,946	40,816	40,786	40,786	39,818	39,818
Anticipated Reserve Margin (%)	17.6%	14.8%	14.9%	13.8%	17.4%	16.7%	16.6%	16.3%	18.3%	20.9%
Prospective Reserve Margin (%)	23.4%	20.9%	21.0%	19.9%	23.5%	22.8%	22.7%	22.4%	24.4%	26.9%
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

Highlights

- The ARM falls slightly below the RML during the summer months of 2025, 2026, and 2027. The entities plan to secure firm transmission imports to support operating plans when resources are deficient.
- Natural gas (40%), coal (30%), and nuclear (18%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types (12%) are minimal.
- From 2023 to 2033, SERC-Central will retire more than 5 GW of coal generation within the next 10 years. Tier 1 additions of nearly 8.6 GW of natural gas, 0.5 GW of BES-connected solar PV, and 0.1 GW of BESS is expected during this time.
- Historically a summer peaking area, SERC-Central has now become a dual-peaking system.
- The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 0.2% on average in the next 10 years.

SERC-Central Generation Capacity by Fuel Type (Summer)										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	13,235	13,235	13,235	11,661	10,934	9,804	9,804	9,804	8,836	8,836
Petroleum	148	148	148	148	148	148	148	148	148	148
Natural Gas	19,888	19,618	19,618	20,964	23,174	24,022	23,992	23,992	25,813	27,139
Biomass	36	36	36	36	36	36	36	36	36	36
Solar	647	983	987	987	987	987	987	987	987	987
Wind	4	4	4	4	4	4	4	4	4	4
Conventional Hydro	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315
Pumped Storage	1,691	1,691	1,691	1,691	1,691	1,691	1,691	1,691	1,691	1,691
Nuclear	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280
Battery	81	141	141	141	141	141	141	141	141	141
Total MW	47,324	47,450	47,454	47,226	48,709	48,427	48,397	48,397	49,250	50,576

SERC-Central Assessment

Planning Reserve Margins

The ARM for the SERC-Central assessment area falls slightly below the NERC target reference margin of 15% during the summer months of 2025, 2026, and 2027. Economic development and load growth contribute to an increase in anticipated demand in the near-term future. SERC-Central is also retiring a total of 3,260 MW summery capacity of mostly coal generation by the year 2027, which is reflected through the three-year span. A Tier 1 capacity addition of 3,556 MW in natural gas generation is expected to alleviate the capacity shortage in summer months starting in 2028. SERC-Central entities will use internal processes to review season-ahead and prompt-year positions to ensure reserve margins are adequate in the near term. The entities are constantly monitoring load growth and use additional market capacity as needed. A large entity has recently entered into several short-term power purchase agreements and secured additional firm transmission to help mitigate near-term capacity needs. The entity maintains a diverse portfolio of generating resources with a variety of fuel procurement sources. This variety provides a natural hedge against supply concerns from any one source that could pose a risk to its overall generation.

Energy Assessment and Non-Peak Hour Risk

Entities incorporate energy risks, such as extreme weather, outages (forced and planned), interchange limits, and renewable variability into their loss-of-load probabilistic studies. These results are used to determine the margin targets, generation portfolios, and power contract requirements. They also assist in long term investment and commercial actions to mitigate reserve margin shortfalls. SERC-Central did not identify any increase in energy risk concerns due to the relatively low solar PV and wind penetration. However, ramping needs are expected to increase over time as more solar PV is added to the system. The entities plan to add more storage and flexible dispatchable gas generation to help mitigate the impacts.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.00	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	18.4%	18.6%	17.1%

* Provides the 2022 ProbA Results for Comparison

SERC-Central has been transitioning from a summer-peaking to a dual-peaking system in the last few years and is projected to continue in that trend. The reliability risk as indicated by the 2022 ProbA is projected to be stable. The 2022 ProbA results indicate no LOLHs or EUE based on data and modeling assumptions. The severe cold weather stress test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand

Historically a summer peaking area, SERC-Central has now become a dual-peaking system. The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 0.2% on average in the next 10 years.

Demand-Side Management

Controllable and dispatchable DR programs are considered available during peak hours from June through September. The amount of MW available is highly dependent on the weather and is estimated based on historical performance. While some program events are dispatched and monitored near real-time, customers receive monthly capacity payments and energy payments based on performance during events. Dispatchable voltage regulation can operate distribution feeder voltages in the lower half of the standard voltage range to lower peak demand. Electric system distribution feeders utilize a voltage feedback loop to bias voltage regulators to maintain the lowest acceptable feeder voltage during an economic event. Interruptible DR program can suspend a portion of participating customers’ load with 5- or 30-minutes notice during times of the power system need.

Distributed Energy Resources

The impact of DER resources is forecasted and incorporated into the total energy and peak demand forecasts. Entities do not always include the growth of DERs in resource planning, however. The BTM solar PV is embedded in the load forecast with an hourly shape derived from solar irradiance. The solar PV is often a fixed energy supply resource modeled as an hourly generation profile in a typical week pattern each month derived from simulated data. Consideration is given to aligning the solar PV generation with the peak load for the week, particularly in the summer when the highest load for the week will likely occur during the sunniest day of the week.

Generation

Natural gas (40%), coal (30%), and nuclear (18%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types (12%) are minimal. From 2023 to 2033, SERC-Central will retire more than 5 GW of coal generation within the next 10 years. Tier 1 additions of nearly 8.6 GW of natural gas, 0.5 GW of BES-connected solar PV, and 0.1 of GW BESS is expected during this time.

Energy Storage

There is no utility-scale transmission BES-connected BESS at this time. 246 MW of Tier 1 and 770 MW of Tier 2 and Tier 3 nameplate capacity BESS is expected within 10 years.

Capacity Transfers and External Assistance

Severe system events could reduce transfer capacity, possibly affecting a portion of load under summer conditions. The entity would coordinate with neighboring TOP to expedite returning a line to service and shed load if no other options are available. Entities plan to maintain surplus capacity to meet reliability needs during extreme weather scenarios. They will coordinate with its operations personnel, fuel suppliers, pipeline personnel, and neighboring utilities prior to and during weather events.

Transmission

The assessment area will add another 118.4 miles within the first five years followed by 53 miles in the next five years of new ac transmission lines with the voltage range between 100 to 200 kV. These projects are in the planning/construction phase and projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability.

Reliability Issues

SERC and its members have not identified any other emerging reliability issues without existing or planned solutions. However, entities continue to monitor the possible impacts on the long-term reliability of the BES from the supply chain issues, changing resource mix, transmission projects and temporary mitigations, summer and dual peaking scenarios, extreme weather events, and critical infrastructure sector interdependency.

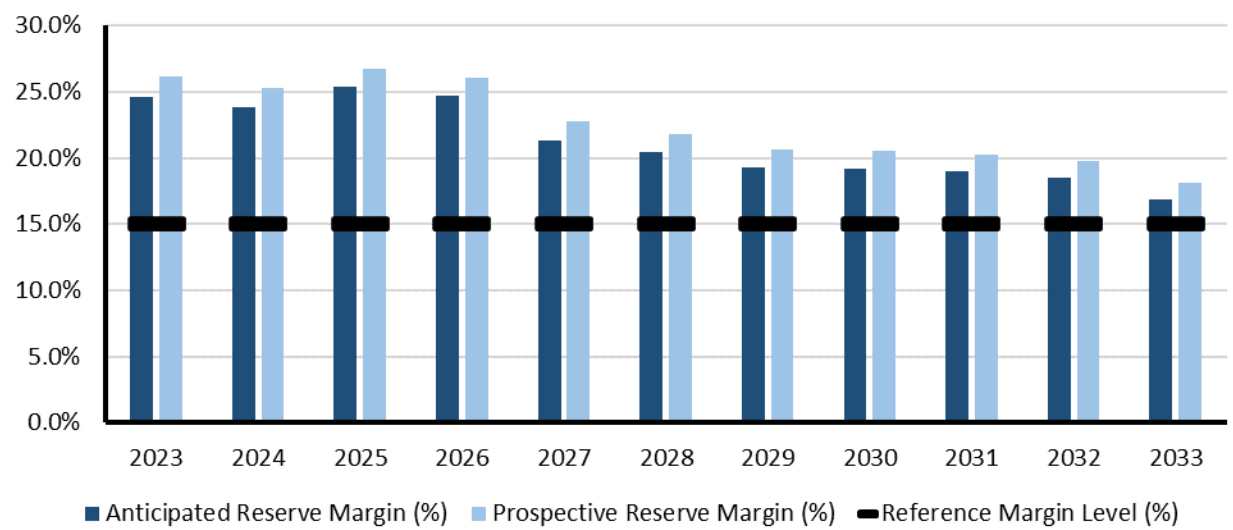
High transfers across the transmission system and their impacts on reliability driven by high regional wind and extreme weather events is an area of risk. To support reliability across the year with changes in generation resources, a dual peaking entity has adopted separate reserve margin targets for winter and summer seasons with plans for effective outage planning in off-peak periods. The entity studied a peak summer demand with low hydro scenario to reflect drought weather conditions and has identified projects to address the more severe reliability concerns. This assessment area can tackle fuel resilience risks with a well-diversified generation portfolio and 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. In addition, entities identified improvement opportunities for both normal operating conditions and to allow for more effective response and restoration activities under severe scenarios.

SERC-Florida Peninsula

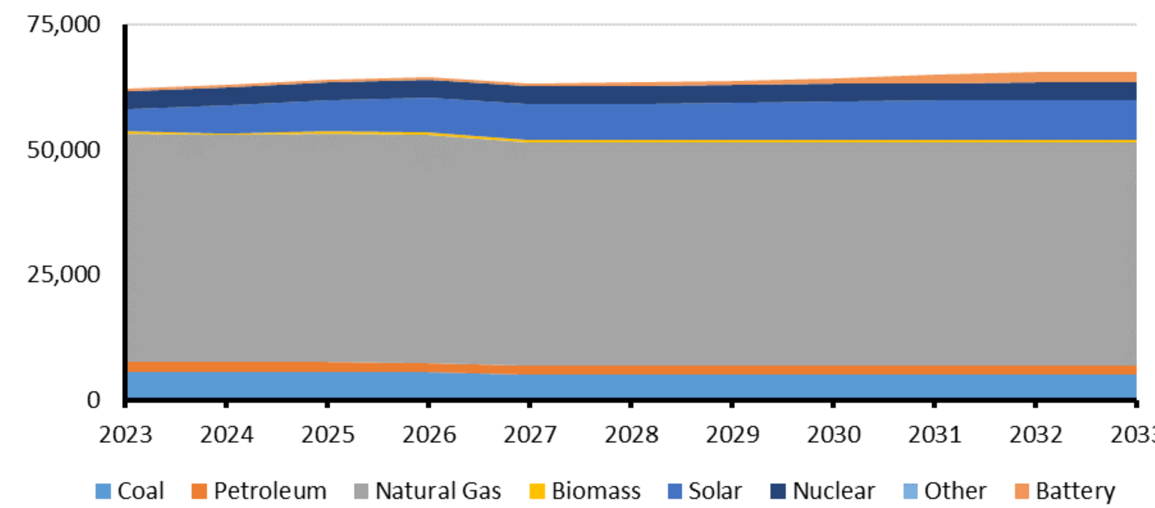
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 PAs, and 7 RCs. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	53,190	53,591	54,107	54,516	54,977	55,719	56,407	57,036	57,847	58,667
Demand Response	2,924	2,957	2,988	3,022	3,064	3,109	3,155	3,202	3,247	3,288
Net Internal Demand	50,266	50,634	51,119	51,494	51,913	52,610	53,252	53,834	54,600	55,379
Additions: Tier 1	1,549	2,394	3,099	3,281	3,464	3,735	4,419	5,004	5,660	5,660
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	594	700	499	499	406	406	406	406	406	406
Existing-Certain and Net Firm Transfers	60,700	61,062	60,624	59,204	59,035	59,035	59,035	59,035	59,035	59,035
Anticipated Reserve Margin (%)	23.8%	25.3%	24.7%	21.3%	20.4%	19.3%	19.2%	19.0%	18.5%	16.8%
Prospective Reserve Margin (%)	25.3%	26.7%	26.1%	22.7%	21.8%	20.7%	20.5%	20.3%	19.8%	18.1%
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

Highlights

- The ARMs are above the RML throughout the assessment period.
- Natural gas (73%), coal (9%), and nuclear (6%) are among the primary fuel types within the assessment areas. Renewables and other fuel types make up the remaining (12%) generation.
- From 2023 to 2033, SERC-Florida Peninsula will retire nearly 0.5 GW of coal generation. Tier 1 addition of nearly 0.9 GW natural gas, 3.5 GW BES-connected solar PV, and 1.6 GW BESS is expected during this time.
- SERC-Florida Peninsula is a summer-peaking assessment area.
- The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area, is expected to grow annually at a rate of approximately 1% on average in the next 10 years.

SERC-Florida Peninsula Generation Capacity by Fuel Type

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	5,172	5,172	5,172	4,713	4,713	4,713	4,713	4,713	4,713	4,713
Petroleum	2,017	2,017	1,846	1,718	1,718	1,718	1,718	1,718	1,718	1,718
Natural Gas	44,424	44,717	44,650	43,832	43,756	43,756	43,793	43,793	43,793	43,793
Biomass	429	429	429	414	414	414	414	414	414	414
Solar	5,565	6,273	6,978	7,161	7,344	7,526	7,709	7,891	8,032	8,032
Nuclear	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502	3,502
Other	12	12	12	12	12	12	12	12	12	12
Battery	534	634	634	634	634	723	1,187	1,589	2,104	2,104
Total MW	61,655	62,756	63,223	61,986	62,092	62,364	63,048	63,632	64,288	64,288

SERC-Florida Peninsula Assessment

Planning Reserve Margins
SERC -Florida Peninsula ARMs are above the RML throughout the assessment period.

Energy Assessment and Non-Peak Hour Risk
The entities collaborate and run probabilistic assessments that look at every hour of the 5-year study period to determine where a potential energy adequacy risk may arise. Additional scenario cases are also evaluated, such as unavailability of firm imports, DR, and 90/10 load projection. The study results observed in the months surrounding the peak month simulate additional scheduled maintenance outages while the projected demand begins to ramp up to its seasonal peak levels. The current energy assessments do not explicitly evaluate system ramping needs. Over the next few years, The FRCC Planning and Operating Committees plan to further evaluate system ramping needs and determine if system ramping could become a challenge for the overall footprint. The results of the loss-of-load probability study are used in combination with deterministic analyses to determine if the planned resources meet adequacy requirements.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	2.26	1.09	1.13
EUE (PPM)	0.009	0.004	0.004
LOLH (hours per Year)	0.004	0.002	0.002
Operable On-Peak Margin	11.4%	18.3%	18.6%

* Provides the 2020 ProbA Results for Comparison

SERC-Florida Peninsula is a summer-peaking assessment area. The reliability risk, as indicated by the 2022 ProbA, is projected to be stable. The 2022 ProbA results indicate low to no risk of LOLHs or EUE based on data and modeling assumptions. The severe cold weather stress-test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand
SERC-Florida Peninsula is a summer-peaking assessment area. The net non-coincident internal demand, which includes the available, controllable, and dispatchable DR for the assessment area is expected to grow annually at a rate of approximately 1% on average in the next 10 years.

Demand-Side Management
Controllable DR from interruptible and dispatchable load management programs is treated as a load-modifier and projected to be constant at approximately 6% of the summer and winter total peak demands for all years of this assessment period. Entities develop their own independent forecast of firm controllable and dispatchable DR values to be available at system peak based on their methodology and program policies. These individual reporting entities perform and develop independent analyses of the estimated impacts from their firm DR and load management. The impacts are aggregated for analytical purposes in the assessment area.

Distributed Energy Resources
The FRCC performs an annual collection of Distributed Energy Resources across the membership. Entities utilize the NERC published definitions of DERs when forecasting, monitoring, and reporting. In general, FRCC member DERs are modeled as being netted out with the actual customer demand since they are implicitly accounted for in the load forecasts of entities. Increased penetration levels of BTM PV continues to be observed year over year and is anticipated to continue; however, at relatively low penetration levels when compared to the Total Demand of the assessment area. In addition, members of the resource, transmission, technical and stability analysis subcommittees annually perform reviews of the DER penetration levels to determine if additional study work or sensitivities are needed. At this time, no additional challenges from increased penetration levels of DERs have been identified by the Planning Coordinators and Transmission Planners in the assessment area.

Generation
Natural gas (73%), coal (9%), and nuclear (6%) are among the primary fuel types within the assessment areas. Renewables and other fuel types make up the remaining (12%) generation. From 2023 to 2033, SERC-Florida Peninsula will retire nearly 0.5 GW of coal generation. Tier 1 addition of nearly 0.9 GW natural gas, 3.5 GW BES-connected solar PV, and 1.6 GW BESS is expected during this time.

Energy Storage
There is 519 MW of utility-scale transmission BES-connected BESS at this time. 1,585 MW of Tier 1 nameplate capacity BESS is expected within 10 years.

Capacity Transfers and External Assistance

The assessment area has one interface to the Eastern Interconnection made up of multiple transmission facilities. The owners of these facilities on each side of the subregions study various scenarios to determine transfer capabilities into and out of the assessment area. There are various contingencies that could limit the transfer capability into and out of the subregion that could result in potential reliability impacts. Those potential impacts would be mitigated by the various operating entities affected, including the FRCC Reliability Coordinator and Southeastern Reliability Coordinator.

Transmission

The assessment area will add another 67.6 miles within the first five years followed by 40.2 miles in the next five years of new AC transmission lines with the voltage range between 100 to 200 kV. The assessment area will add another 193.1 miles within the first five years followed by 9.3 miles in the next five years of new AC transmission lines with the voltage range between 200 to 300 kV. These projects are in the planning/construction phase and projected to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts to reliability.

Reliability Issues

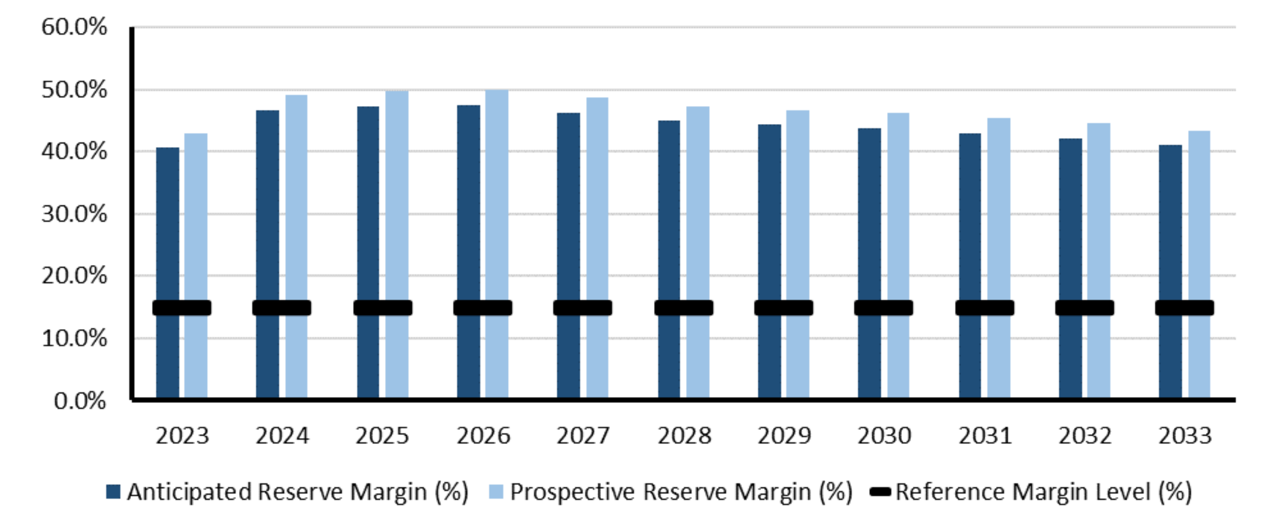
The 10-year projected total reserve margin is above 15%, and this assessment area remains under the industry standard metric of 0.1 loss-of-load probability. Although expected resources meet operating reserve requirements under normal peak-demand scenarios, supplemental analysis on significant and sustained temperature deviations from normal winter peak load and outage conditions identified that operating mitigations (i.e., DR and transfers) and energy emergency alerts (EEAs), including potential load shedding that may be needed under extreme peak demand and outage scenarios studied. The entities continue to monitor the possible impacts on the long-term reliability of the BES from the changing resource mix, the higher penetration of IBR generation, the risks of extreme weather, and the assessment area's dependency on natural gas as a fuel resource.

SERC-Southeast

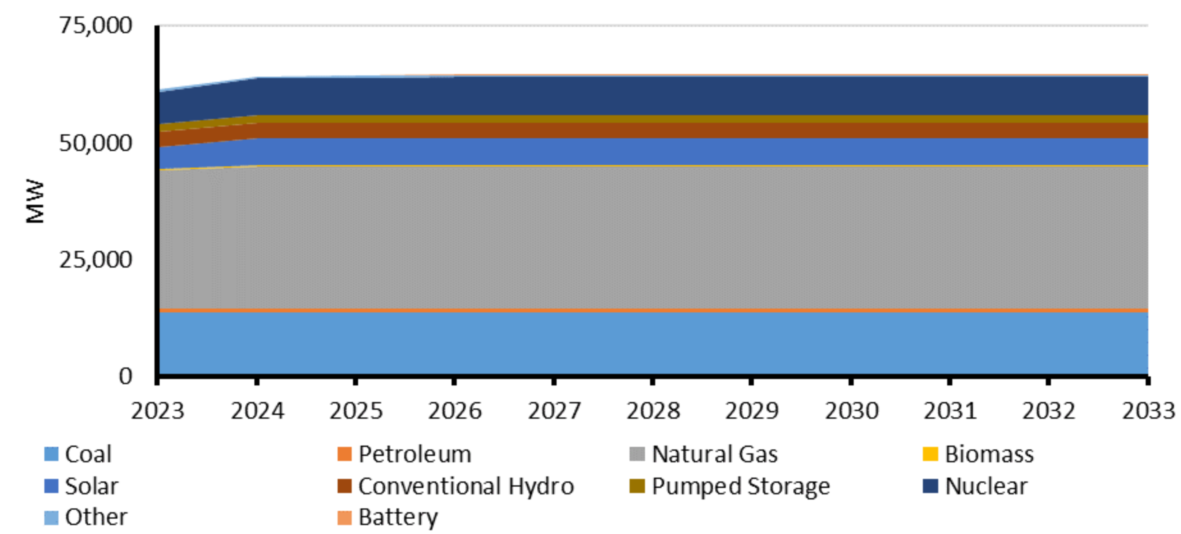
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 34 Balancing Authorities, 27 Planning Authorities, and 7 RCs. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	46,354	45,595	45,831	46,267	46,555	46,753	47,050	47,311	47,570	47,937
Demand Response	2,069	2,246	2,341	2,380	2,282	2,286	2,285	2,285	2,285	2,285
Net Internal Demand	44,285	43,349	43,490	43,887	44,273	44,467	44,765	45,026	45,285	45,652
Additions: Tier 1	2,679	2,921	3,186	3,186	3,186	3,186	3,186	3,186	3,186	3,186
Additions: Tier 2	218	218	218	218	218	218	218	218	218	218
Additions: Tier 3	299	426	426	426	426	426	426	426	426	426
Net Firm Capacity Transfers	-971	-471	-471	-471	-471	-471	-256	-256	-256	-256
Existing-Certain and Net Firm Transfers	60,294	60,819	60,878	60,878	60,878	60,878	61,093	61,093	61,093	61,093
Anticipated Reserve Margin (%)	42.2%	47.0%	47.3%	46.0%	44.7%	44.1%	43.6%	42.8%	41.9%	40.8%
Prospective Reserve Margin (%)	44.6%	49.5%	49.8%	48.4%	47.1%	46.5%	46.0%	45.1%	44.3%	43.1%
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

Highlights

- SERC-Southeast show ARMs above the RML during the first five years of this assessment period.
- Natural gas (47%), coal (22%), and nuclear (13%) generation are the dominant fuel types within the assessment areas. Hydro, renewables, and other fuel types make up the remaining (18%) generation.
- The assessment area will add 788 MW of natural gas generation over the period. 3,937 MW of utility-scale transmission BES-connected Tier 1 solar PV projects are expected in the next 10 years. Overall, there will be 1,878 MW of net additions and retirements within the next 10 years.
- There is no utility-scale transmission BES-connected BESS at this time. 330 MW of Tier 1 nameplate capacity BESS is expected within 10 years.

SERC-Southeast Generation Capacity by Fuel Type										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	13,770	13,770	13,770	13,770	13,770	13,770	13,770	13,770	13,770	13,770
Petroleum	915	915	915	915	915	915	915	915	915	915
Natural Gas	30,023	30,048	30,107	30,107	30,107	30,107	30,107	30,107	30,107	30,107
Biomass	424	424	424	424	424	424	424	424	424	424
Solar	5,496	5,738	5,738	5,738	5,738	5,738	5,738	5,738	5,738	5,738
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	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018	8,018
Other	313	313	313	313	313	313	313	313	313	313
Battery	65	65	330	330	330	330	330	330	330	330
Total MW	63,944	64,211	64,535	64,535	64,535	64,535	64,535	64,535	64,535	64,535

SERC-Southeast Assessment

Planning Reserve Margins

SERC-Southeast shows ARMs above RML during this assessment period.

Energy Assessment and Non-Peak Hour Risk

Many entities perform probabilistic assessments to identify energy risk. These assessments cover different scenarios such as hydro generation off-line, low solar PV output scenarios, potential environmental-related generation plant retirements, extreme weather impacting supply to natural-gas-fired generation plants, and unexpected loss of large generation units. The energy adequacy assessment results do not show increased risk outside of expected peak demand hours while considering expected ramping requirements, fuel, and generator availability as well as load forecast uncertainty scenarios. The assessments have demonstrated a need for additional transmission capacity to facilitate the displacement of traditional fossil-fueled generation resources. Lower solar PV output has not yet resulted in system reliability issues due to available alternate resources, but future reserve planning is a concern. DER penetration is currently low and does not significantly contribute to load forecast, particularly for winter periods. The results from the energy assessment are used for support in fuel and capacity appropriation decisions. Additionally, the results are used to determine the amount of seasonal reserve capacity that will be maintained based on the current forecasted peak season demand.

Probabilistic Assessments

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	0.03	0.00	0.00
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	30.2%	26.8%	30.8%

* Provides the 2020 ProbA Results for Comparison

SERC-Southeast is slightly winter peaking. The 2023 LTRA data indicates more coal retirements than anticipated in the 2022 LTRA. The reliability risk, as indicated by the 2022 ProbA, is projected to be stable. The 2022 ProbA results indicate no loss-of-load hours or EUE based on data and modeling assumptions. The severe cold weather stress test indicated that there is some risk of customer interruption and loss of energy in the case of combining unusual weather with higher-than-anticipated generator unit outages.

Demand

Each consumer class can have an econometric forecast based on load factor, demand ratio, trend analysis, weather, appliance efficiency, large load adjustment, and load profile models. The weather is a key driver in the forecast process. Regression models relating weather and the economy to energy sales can predict future sales for customers. Load factors and diversity ratios can determine the peaks. Future hourly load shapes are derived from historical hourly load shapes and the forecasted demand and energy. Customer load shapes are added together to form the hourly load shape for its system. Temperature sensitivities are utilized to develop weather case extreme forecast. Discreet adjustments are examined outside of the models for analysis on how DERs impact the forecast. The variable resources do not generally contribute to load forecast uncertainty in long-range forecast. Some entities use the Statistically Adjusted End-Use model, which combines the strengths of econometric and end-use methodologies by incorporating the detail of end-use models while maintaining the ease of use associated with econometric models. The Statistically Adjusted End-Use Model allows the entity to evaluate the function of price, income, population, appliance saturations, market shares, and specifically the importance of weather in determining usage. The model incorporates member cooperative results from their residential end-use surveys, thus capturing any new technology (electric vehicles, residential solar PV) that could affect usage. Each year, historical data will be added to the LF databases for each member, and new regression equations will be developed and evaluated with the SAE model to forecast average residential usage as well as a linear regression equation to forecast non-residential sales. The summer and winter peaks are projected with the most probable weather conditions (50/50 forecast). The historical relationship between total system load levels and weather will continue to be the key component in developing an hourly demand forecast for the total system load.

Demand-Side Management

The demand side management water heater program allows system operators to control appliance usage during peak demand periods. The number of installed water heater control switches are accounted for each month. Historical trends are used to forecast the number of water heater control switches to be installed in future years. Entities monitor and dispatch DR programs per individual contract terms. Annual ELCC simulations are performed to determine the capacity value for each unique and active DR program. An adjustment to that capacity value is then made based on predicted customer response when the program is called or dispatched. The impacts of BTM DERs are accounted for in the development of the annual load forecasts. In front-of-the-meter DERs are considered separate generation resources and do not impact any current demand-side management programs.

Distributed Energy Resources

Some entities record DER contributions by the sum of their capacities for each metering point served via distribution transformers. When DER capacities at a certain metering point meet or exceed a certain level, estimated generation is placed back onto the load bus for load forecasting purposes. Entities model DERs as hourly profiles in all resource planning models, thereby taking into consideration ramping and other operational considerations. The forecast of BTM solar PV is based on a trend model for MWs. This MW forecast is then converted to an energy forecast by using an assumed capacity factor.

The BTM solar PV forecast increases through the assessment period. On a yearly basis, the reliability model is updated based on the latest system Integrated Resource Plan. Capacity values for proposed and newly added DER resources are then calculated based on the current yearly model assumptions. Projections of solar PV are included in the Base Case forecast on the demand side. However, demand-side BESS and other BTM resources are not prevalent and are not included.

Generation

- Natural gas (47%), coal (22%), and nuclear (13%) generation are the dominant fuel types within the assessment area. Hydro, renewables, and other fuel types make up the remaining (18%) generation.
- The assessment area will add 788 MW of natural gas generation over the period.
- Overall, there will be 1,878 MW of net additions and retirements within the next 10 years.
- 2,399 MW of utility-scale transmission BES-connected Tier 1 solar PV projects are expected in the next 10 years.

Energy Storage

- There is no utility-scale transmission BES-connected BESS at this time.
- 330 MW of Tier 1 nameplate capacity BESS is expected within 10 years.

Capacity Transfers and External Assistance

Entity studies confirmed Open Access Same-Time Information System (OASIS) reservations in its long-term assessments and plans for the delivery of those commitments under a variety of scenarios including different load levels and system flow patterns. For imports into the system, OASIS reservations for the capacity benefit margin and Transmission Reliability Margin are included and planned for. Any concerns that are identified in these assessments are reviewed with neighboring utilities, and evaluations are coordinated when necessary to determine optimal solutions.

Transmission

- The assessment area will add another 369.3 miles within the first five years followed by 109.1 miles in the next five years of new AC transmission lines with the voltage range between 100 to 200 kV.
- The assessment area will add another 229.9 miles within the first five years followed by 4.8 miles in the next five years of new AC transmission lines with the voltage range between 200 to 300 kV.
- The assessment area will add another 101.6 miles within the first five years followed by 65.0 miles in the next five years of new AC transmission lines with the voltage range higher than 400 kV.
- These projects are in the planning/construction phase and projected to enhance system reliability by supporting voltage and relieving challenging flows.
- Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.
- Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

Reliability Issues

Electromagnetic transient studies of in-service IBRs in relatively weak areas of the system have been deemed necessary for some entities. This is important to determine appropriate ramp rates, controller settings, and ride-through capabilities for available generation. The potential impacts of driving this need are unexpected responses (voltage oscillations, power quality impacts, etc.) observed during disturbances or abnormal configurations. Extreme weather study processes are evolving, and more emphasis is being placed on extreme cold due to recent events in other areas. Extreme weather events are included as part of the load and weather patterns considered in its probabilistic determination of reserve margins. Additionally, fuel price volatility and fuel availability continue to present challenges that have resulted in various scenarios being studied and evaluated on a continuous basis by some entities. Entities identify potential common mode failures within the natural gas subsector through various processes and studies and coordinate with their critical natural gas facilities, local electric sector participants, and fuel suppliers in performing assessments to ensure any facilities critical to maintaining fuel availability are not included in its load shedding procedures

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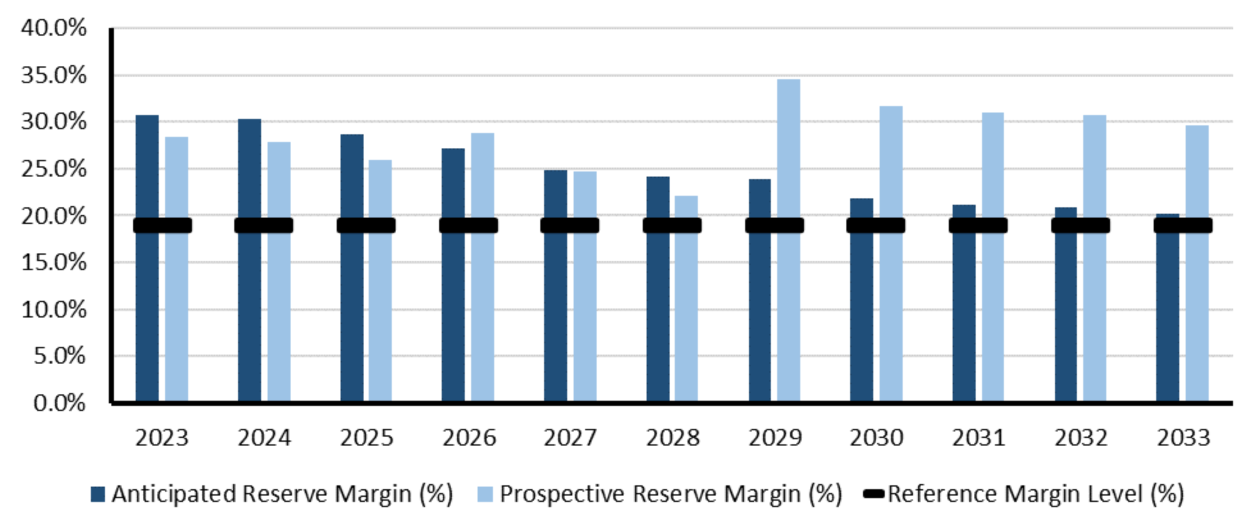
SPP

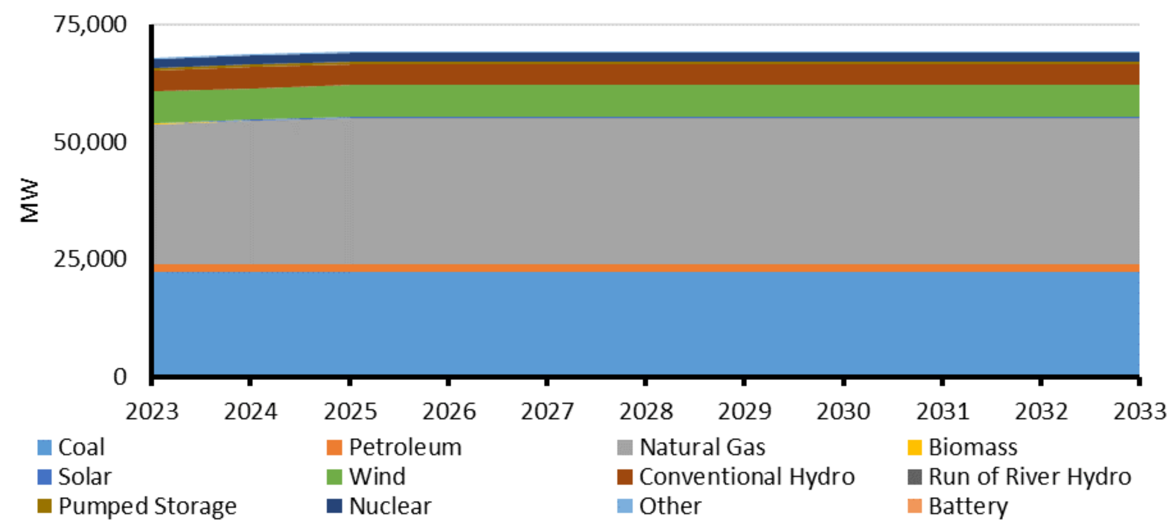
The SPP Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning 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. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	53,603	54,846	55,784	56,754	57,048	57,249	58,253	58,557	58,908	59,242
Demand Response	1,353	1,489	1,772	1,798	1,807	1,843	1,851	1,857	2,062	2,046
Net Internal Demand	52,250	53,356	54,012	54,957	55,240	55,405	56,402	56,700	56,846	57,196
Additions: Tier 1	718	1,302	1,302	1,302	1,302	1,302	1,302	1,302	1,302	1,302
Additions: Tier 2	0	0	2,739	2,739	2,739	9,795	9,795	9,795	9,795	9,795
Additions: Tier 3	0	0	4,205	4,205	4,205	4,205	4,205	4,205	4,205	4,205
Net Firm Capacity Transfers	-404	-384	-364	-474	-469	-469	-400	-400	-402	-402
Existing-Certain and Net Firm Transfers	67,371	67,391	67,411	67,301	67,306	67,306	67,418	67,418	67,416	67,416
Anticipated Reserve Margin (%)	30.3%	28.7%	27.2%	24.8%	24.2%	23.8%	21.8%	21.2%	20.9%	20.1%
Prospective Reserve Margin (%)	27.8%	25.9%	28.8%	24.7%	22.2%	34.5%	31.7%	31.0%	30.7%	29.7%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- ARMs do not fall below the RML for this assessment period.

SPP Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	22,283	22,283	22,283	22,283	22,283	22,283	22,283	22,283	22,283	22,283
Petroleum	1,728	1,728	1,728	1,728	1,728	1,728	1,728	1,728	1,728	1,728
Natural Gas	30,544	31,128	31,128	31,128	31,128	31,128	31,128	31,128	31,128	31,128
Biomass	35	35	35	35	35	35	35	35	35	35
Solar	201	201	201	201	201	201	201	201	201	201
Wind	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713	6,713
Conventional Hydro	4,418	4,418	4,418	4,418	4,418	4,418	4,418	4,418	4,418	4,418
Run of River Hydro	75	75	75	75	75	75	75	75	75	75
Pumped Storage	440	440	440	440	440	440	440	440	440	440
Nuclear	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944
Other	281	281	281	281	281	281	281	281	281	281
Battery	1	1	1	1	1	1	1	1	1	1
Total MW	68,664	69,248	69,248	69,248	69,248	69,248	69,248	69,248	69,248	69,248

SPP Assessment

Planning Reserve Margins

ARMS do not fall below the RML of 19% (based on SPP coincident peak demand) for the entire ten-year assessment period. While the SPP ARM shows a robust amount of excess capacity, these margins reflect the full availability of accredited capacity and do not account for planned, forced or maintenance outages. The SPP ARM also does not reflect de-rates based on real time operational impacts. Similar to the Generation Unavailability scenario in the *2023 NERC Summer Reliability Assessment*, SPP shows the potential to use all of the LTRA ARM capacity, which means there could be times of capacity shortfall based on performance impacts during high load periods. While the potential to use all of the LTRA ARM capacity has a low probability, the assumptions and projections are based around historic unavailability during on-peak periods.

The RML of 19% was established by SPP and its stakeholders and is based on results of the most recent biennial LOLE study.[51] The study analyzes the ability to reliably serve the SPP BA area's 50/50 forecasted peak demand with a security constrained economic dispatch. SPP, with stakeholder input, develops the inputs and assumptions used for the LOLE Study. SPP will study the Planning Reserve Margins such that the LOLE for the applicable planning year (2- and 5-year study) does not exceed 1-day-in-10 years, or 0.1 day per year. At a minimum, the RML will be determined with 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. The 2023 LOLE study is underway in SPP but will not be completed prior to publication of the *2023 LTRA*.

Energy Assessment and Non-Peak Hour Risk

As the resource mix continues to change from a baseload thermal and hydro resources to VERs and short duration energy storage resources, SPP recognizes that its LOLE study must also continue to evolve. A potential change and improvement identified for the 2023 LOLE study includes considering energy adequacy and additional metrics (e.g., EUE).

Probabilistic Assessments

SPP's most recent study performed for NERC's Probabilistic Assessment (2022 ProbA) found negligible risk of load loss in the Base Case for both study years. All unserved energy was concentrated in peak summer months.

Base Case Summary of Results (2022 ProbA)			
	2024*	2024	2026
EUE (MWh)	0.00	0.27	0.84
EUE (PPM)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
Operable On-Peak Margin	13.3%	19.7%	19.6%

* Provides the 2020 ProbA Results for Comparison

In 2023, SPP completed a probabilistic analysis of a winter risk scenario that paired increases in both conventional forced generation outages and peak demand. The scenario was carried out for the 2026 study year by using the 90/10 winter load forecast and increasing the forced outage rate of the conventional fleet by a factor of two.[52] In this scenario, some energy goes unserved in winter months and overall EUE rises to 1.36 MWh.

Demand

SPP peak load occurs during the summer season. The 2024 load forecast is projected to peak at 53,603 MW, which is a 1% increase compared to the previous year's LTRA forecast for the 2024 summer season. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment time frame. The diversity factor used to convert members' non-coincident peak demand forecasts to an SPP coincident peak demand forecast is consistent with the percentage used for the 2022 LTRA. The current annual growth rate is approximately 1%.

Demand-Side Management

SPP's EE and conservation programs are incorporated into the reporting entities' demand forecasts. The SPP assessment area is projecting a significant amount of DR to come online over the assessment time frame and is currently working on accreditation methodologies to better access reliability contributions from these programs. DR resources are projected to rise sharply over the assessment period from the current contribution of 829 MW to over 2,000 MW by 2033. As an additional sensitivity to the 2023 LOLE study, SPP modeled high level constraints applied to the current DR programs to understand the possible reliability impacts when constraining the programs to a certain limited number of calls per year and limited number of hours per day. Additionally, SPP is working with stakeholders to gather program specific details that can be modeled. With the footprint's projected DR growth, it will be important to model these programs accurately to better depict the

[51] SPP LOLE Study Report

[52] See 2022 ProbA Regional Risk Scenarios Report. The scenario was created in early 2022. Since then, significantly higher forced outage rates have been observed in severe winter events, such as winter storm Elliott.

reliability implications to the SPP system. DR growth and electrification have the potential to introduce new demand forecast uncertainty and reliability risk.

Distributed Energy Resources

SPP currently has approximately 300 MW of installed solar PV generating facilities. The SPP Model Development, Economic Studies, and Supply Adequacy working groups are currently developing policies and procedures around DERs. SPP implemented resource adequacy policies for DERs that require certain testing, reporting and documentation requirements for resources and programs not registered with approval planned for late 2023.

Generation

Since the 2022 LTRA, SPP members have reported approximately 1,500 MWs of conventional resources being retired. There are no known unaddressed reliability impacts at this time. Retirements continue to be assessed throughout the time frame through planning and operational processes. The reliability impacts that retired generation have on the transmission system are also analyzed in the annual Integrated Transmission Plan. Some projected retirements in the assessment time frame are currently expected to be replaced with renewable resources. The confirmed retirement impact to resource adequacy in the assessment area is being studied in the 2023 LOLE study.

In 2023, FERC rejected SPP's proposed ELCC methodology for wind and solar PV resource capacity accreditation. SPP is currently working on revising ELCC policy for wind, solar PV, and storage with the goal of obtaining internal approvals and refiling with FERC in late 2023. More properly accrediting wind, solar PV, and storage resources becomes critical as more conventional generators nearing retirement cause SPP historical Planning Reserve Margin levels to decline.

Energy Storage

There are approximately 17,000 MWs of energy storage and hybrid resources in SPP's generator interconnection queue that are being studied. A small amount (about 50 MWs) of these resources are currently under contract by members across the SPP assessment area. These resources are modeled as generation in both near and long-term planning assumptions.

Capacity Transfers and External Assistance

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 Planning Coordinator footprints. The modeled transactions are fed into the models created for the SPP planning process.

SPP and ERCOT have executed a coordination plan that 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. SPP's and ERCOT's last annual update the coordination plan occurred in June 2023.

Transmission

After evaluating more than 1,080 solutions, SPP worked together with its member organizations to create a robust portfolio of 44 transmission projects, including 51 miles of new extra-high-voltage transmission that can holistically address the reliability, economic, policy, and operational needs of the system. The recommended portfolio contains reliability and economic projects that will mitigate 137 system issues.[53] The *SPP 2024 Integrated Transmission Plan Assessment* and the *2022 SPP Transmission Expansion Plan* reports provide details for proposed transmission projects needed to either maintain reliability and/or provide economic benefit to end users.

Reliability Issues

There are concerns of drought conditions impacting the Missouri River and other water sources for generation resources that rely on once-through cooling processes. Low water can impact the generation's capacity output and reduce its ability to support congestion management and serve load. An additional concern could be the low water's impact on coal availability, which could cause units to run at a derated level to conserve coal inventory. In order to identify mitigations prior to peak conditions, these extreme conditions are studied in SPP's seasonal assessment process. Closer to real time, additional analysis are performed with more accurate forecast data.

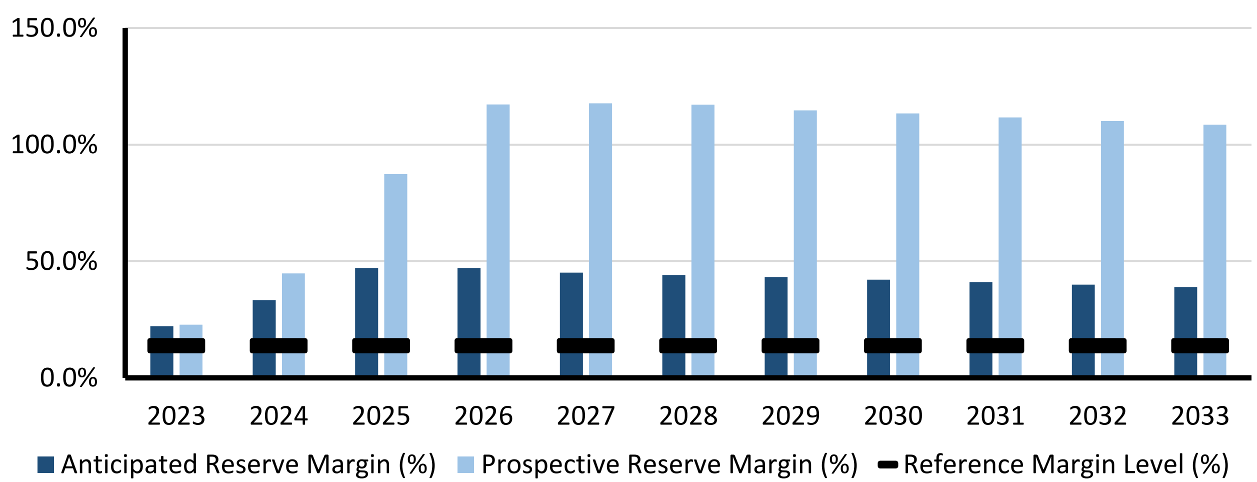
[53] 2022 ITP Report

Texas RE-ERCOT

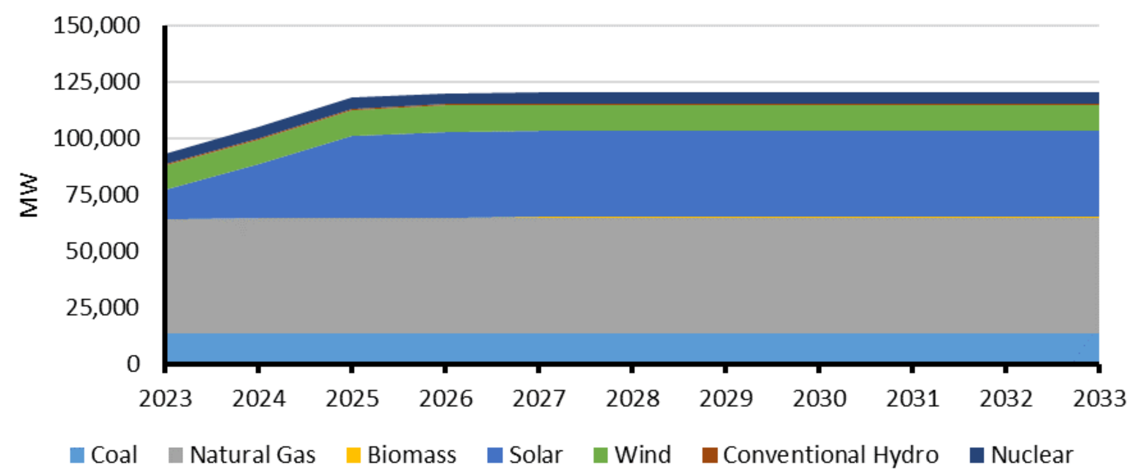
The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single Balancing Authority. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer peaking. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,030 generation units, and serves more than 26 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Regional Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	84,325	85,740	87,131	88,518	89,090	89,624	90,298	90,986	91,646	92,296
Demand Response	3,464	3,464	3,464	3,464	3,464	3,464	3,464	3,464	3,464	3,464
Net Internal Demand	80,861	82,276	83,667	85,054	85,626	86,160	86,834	87,522	88,182	88,832
Additions: Tier 1	12,520	25,802	27,852	28,010	28,010	28,010	28,010	28,010	28,010	28,010
Additions: Tier 2	8,618	33,248	58,809	63,012	64,574	64,574	64,874	64,874	64,874	64,874
Additions: Tier 3	7,589	11,955	23,097	26,029	27,828	28,226	28,226	28,226	28,226	28,226
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	95,260	95,260	95,260	95,405	95,405	95,405	95,405	95,405	95,405	95,405
Anticipated Reserve Margin (%)	33.3%	47.1%	47.1%	45.1%	44.1%	43.2%	42.1%	41.0%	40.0%	38.9%
Prospective Reserve Margin (%)	44.8%	87.4%	117.2%	117.7%	117.2%	114.7%	113.4%	111.7%	110.1%	108.6%
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

- Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2024–2033). The ARM peaks at 47% by summer 2025, reflecting the expected addition of 25,802 MW of Tier 1 capacity, most of which is solar PV.
- ERCOT's summer peak demand is forecasted to increase by 1.1% per year through 2033 while annual energy is forecasted to increase by 2.1% per year for the same period. While these growth rates are close to the values for the load forecast used in the *2022 LTRA*, ERCOT has adopted more extreme weather assumptions to reflect the increasing frequency of extreme weather events experienced over the last several years and the expectation that this trend will continue.
- ERCOT completed its *2022 Regional Transmission Plan* in December 2022. The plan lists 15 major reliability improvement projects out of a total of 89 proposed projects. Currently, there are $10.26 billion of transmission improvement projects that are expected to be put in service between 2023 and the end of 2028.

Texas RE-ERCOT Fuel Composition

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568
Natural Gas	51,088	51,321	51,321	51,471	51,471	51,471	51,471	51,471	51,471	51,471
Biomass	163	163	163	163	163	163	163	163	163	163
Solar	23,587	36,056	38,033	38,191	38,191	38,191	38,191	38,191	38,191	38,191
Wind	11,032	11,612	11,686	11,686	11,686	11,686	11,686	11,686	11,686	11,686
Conventional Hydro	480	480	480	480	480	480	480	480	480	480
Nuclear	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973	4,973
Total MW	104,891	118,173	120,223	120,531	120,531	120,531	120,531	120,531	120,531	120,531

Texas RE-ERCOT Assessment

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2024–2033). The ARM peaks at 47% by summer 2025, reflecting the expected addition of 25,802 MW of Tier 1 capacity, most of which is solar PV. However, the high reserve margin belies concerns about the resource mix in Texas RE-ERCOT—the continuing trend towards less fully dispatchable resources and more IBRs like solar PV and wind—as well as the availability of thermal resources (and associated fuel supplies) for addressing increasing weather volatility and changes to load patterns.

While investigating for the Public Utilities Commission of Texas a reliability standard that encompasses multiple probabilistic reliability measures, ERCOT has proposed a reliability standard framework composed of three measures: frequency, event duration and event magnitude. Pending direction from the Public Utilities Commission of Texas, continued analysis of the reliability standard framework is planned for this summer.

Energy Assessment and Non-Peak Hour Risk

The penetration of solar PV in Texas RE-ERCOT continues to increase the risk of tight operating reserves during hours other than the daily peak load hour. This issue is most acute for the summer season when solar PV generation ramps down during the early evening hours while load is still relatively high. ERCOT's Probabilistic Reserve Risk Model is designed for analysis of the hours with the highest risk of reserve shortages for a seasonal peak demand day. As shown ProbA Base Case chart, the summer 2023 model indicates a progression of increasing hourly EEA risk probabilities from the early afternoon through the early evening hours with the peak EEA probability now occurring for hour-ending 9:00 p.m.

To address energy adequacy concerns, the Public Utility Commission of Texas adopted a performance credit mechanism (PCM) in January 202) as part of a Reliability Standard that the 87th Texas Legislature (by way of Senate Bill 3) directed FERC to implement. The PCM is a new market product that is intended to incentivize development and preservation of dispatchable generation. Under the PCM, generation resources commit to producing more energy during the tightest grid conditions of the year and sell credits to load-serving entities. Since PCM implementation may take up to four years, FERC directed ERCOT to investigate alternative bridging strategies that can be implemented relative quickly. ERCOT proposed modifying the operating reserve demand curve as the preferred approach. The 88th Texas legislative session has passed several bills that address grid reliability and further promote dispatchable resources by including performance penalties for generators with a signed interconnection agreement after January 1, 2026, and a November 2023 ballot measure to provide $7.2 billion in low interest loans and a completion bonus grants for new dispatchable resources of at least 100 MW. This requires ERCOT to consider implementing a new ancillary services program to procure dispatchable reliability reserve services on a day-ahead and real-time basis and placing a cost limit for the PCM of $1 billion (less the cost of the bridging solution), so ERCOT will need to develop reliability plans for areas with high load growth including the Permian Basin.

Probabilistic Assessments

ERCOT's recent study performed for NERC's 2022 ProbA identified LOLH and EUE risk predominantly in the winter, largely driven by the incorporation of additional forced outage risk.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	12.86	492.03	1,235.40
EUE (PPM)	0.03	1.09	2.63
LOLH (hours per Year)	0.01	0.15	0.30
Operable On-Peak Margin	10.2%	36.7%	35.9%

* Provides the 2020 ProbA Results for Comparison

In 2023, ERCOT performed a probabilistic risk scenario that studied the impact of transmission limits on reliability indices as heavy IBRs in one area use transmission to get to its load in the central and eastern parts of Texas for the 2026 study year.[54] Results of this scenario, when compared to the 2022 ProbA Base Case, show that the addition of internal transmission constraints had implications for the reliability of the ERCOT system, resulting in modest EUE increases and a more drastic rise in LOLH.

[54] See 2022 ProbA Regional Risk Scenarios. The scenario was created in early 2022. Since then, significantly higher forced outage rates have been observed in severe winter events, such as winter storm Elliott.

Demand

ERCOT's summer peak demand is forecast to increase by 1.1% per year through 2033 while annual energy is forecasted to increase by 2.1% per year for the same period. While these growth rates are close to the values for the load forecast used in the *2022 LTRA*, ERCOT has adopted more extreme weather assumptions to reflect the increasing frequency of extreme weather events experienced over the last several years and the expectation that this trend will continue. As a result, peak loads are significantly higher than those reported in the *2022 LTRA*. These more extreme weather assumptions are also reflected in the extreme peak loads used for scenario and probabilistic risk analysis.

Since the previous summer, ERCOT has experienced continued rapid load growth in large flexible loads (LFL), i.e., interruptible computer operations such as bitcoin mining. The 2023 load forecast increases the demand due to LFLs by 700 MW per year from 2023 through 2027, resulting in approximately 5,000 MW total LFL load in 2027. LFLs are forecasted to increase ERCOT's 2027 summer peak by 500 MW (10% of this demand responsive load).[55]

Currently there are no adjustments for EVs or BESS in the ERCOT long-term forecast used for the LTRA. ERCOT recently collaborated with a vendor to create an EV forecast that will be integrated into the long-term load forecast in 2023.

Demand-Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of non-controllable load resources providing responsive reserve service and ERCOT's Emergency Response Service. The ERCOT Emergency Response Service consists of 10-minute and 30-minute ramping DRs and distributed generation that can first be deployed when physical responsive reserves drop to 3,000 MW and are not projected to be recovered above 3,000 MW within 30 minutes following the deployment of non-spin reserves. Responsive reserve 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. Post Winter Storm Uri programmatic reforms include increasing the $50 million ERS program budget by 50% and providing ERCOT the flexibility to contract ERSs for up to 24 hours.

The remaining dispatchable DR available to ERCOT is from the transmission and distribution service providers' (TDSP) load management programs. These programs provide price incentives for voluntary load reductions from commercial, industrial, and (most recently) residential loads during EEA events. These programs are available for the months of June through September from 1:00–7:00 pm weekdays (except holidays) and are deployed concurrently with ERSs via ERCOT instruction pursuant to agreements between ERCOT and the TDSPs. TDSP Load Management Programs were also provided for the 2022–2023 winter season.

Distributed Energy Resources

ERCOT is currently working with TDSPs on a more consistent process for how DERs are modelled and dispatched in operations and transmission planning cases. One of the remaining issues to make DERs fully visible for operations and planning assessments is to comprehensively capture "unregistered distributed generation (DG)." Although ERCOT currently has requirements for TDSPs to provide limited unregistered DG data (e.g., rooftop solar PV systems), the data is not suitable for modeling. Approved in the 88th Texas Legislature, HB 3390 authorizes ERCOT to annually require TDSPs to provide unregistered DG information deemed necessary for grid reliability assessment.

Generation

Solar PV capacity continues to be rapidly added to Texas RE-ERCOT, so ERCOT is seeing more severe solar ramps. In June 2023, ERCOT implemented a new ancillary service called "ERCOT Contingency Reserve Service." As the wind and solar PV generation fleet continues to grow, the ERCOT Contingency Reserve Service will give the ERCOT control room the capability to deploy resources that can respond within 10 minutes in anticipation of net demand ramps.

ERCOT conducted a study to assess the impact of integrating potential synchronous condensers in the West Texas system. Following the 2021 Odessa event and subsequent events that resulted in generation loss, ERCOT has intensified its efforts to identify potential corrective measures that can enhance the ride-through performance of IBRs. ERCOT has also proposed new grid code requirements for IBRs to improve voltage ride-through performance to align with IEEE Standard 2800. ERCOT recently proposed that all IBRs must meet the voltage ride-through requirements by the end of 2025.

ERCOT also monitors system inertia on a real-time and forward-looking basis. The need for reliability unit commitment is determined for hours when inertia is not sufficient. ERCOT also uses historical system inertia conditions as an input to determine Responsive Reserve Service requirements and amounts needed for different inertia conditions.

Several mitigation strategies to address fuel acquisition risks have been implemented. For example, ERCOT developed a firm fuel supply service that is intended to help maintain system reliability in the event of a natural gas curtailment or other fuel supply disruption. Firm fuel supply service resources are contracted through a competitive procurement process with a single clearing price with bidders offering capacity with on-site fuel or off-site natural gas storage that meets certain qualification criteria. Based on the procurement experience for the 2022–2023 winter season, ERCOT has proposed improvement to the FFSS procurement process. ERCOT considers limitations for natural-gas-fired generators in its Regional Transmission Plan through the inclusion of extreme events that represent

[55] For the *2023 LTRA*, all LFLs are assumed fully curtailable during an energy emergency condition.

the loss of multiple gas generators following the loss of any single gas pipeline. These events are identified by evaluating the gas-pipeline network topology and survey responses from gas generators.

Improved fuel supply data supports overall reliability operations. During recent cold weather events, not all Resource Entities or their affiliates had purchased enough natural gas to satisfy the level of generation their qualified scheduling entity (QSE) indicated was available in their seven-day Current Operating Plan (COP). To help address this issue, ERCOT has proposed rules requiring a QSE to provide gas purchase constraints data that enables ERCOT to assess the generation resource's ability to run at levels indicated in their Current Operating Plan. ERCOT also recently proposed rules that require a QSE that represents a Generation Resource that uses coal or lignite as its primary fuel to submit to ERCOT a declaration of coal and lignite inventory levels. The proposed seasonal declaration process includes requirements for QSEs to notify ERCOT when inventory levels fall below certain thresholds.

Energy Storage

Currently, there is 3,940 MW of on-line utility-scale BESS capacity in Texas RE-ERCOT that is consuming/discharging energy; these mainly provide ancillary services. For example, BESS provides nearly 68% of ERCOT's regulation up and RRS for PFR. Based on the latest project information in the interconnection queue, ERCOT has 11,800 MW of Tier 1 BESS capacity expected to be operational by the end of 2025.

While BESS can help maintain grid reliability, integration of BESS sources has presented some operational challenges. One challenge is that some BESS systems have failed to deliver the required RRS-PFR response when needed. Another concern is that the growth in non-thermal resources will reduce the diversity of resources providing RRS-PFR, which could lead to NERC Reliability Standard violations. To address this issue, a recently completed study investigates whether there are reliability reasons to establish one or more types of limits on Resources providing RRS-PFR.

Since late 2022, ERCOT has been working on identifying modeling changes to better monitor state-of-charge. ERCOT is researching an initiative to build an state-of-change forecasting system using machine learning models. The forecasts would have a five-minute granularity for the next two hours, and hourly granularity for the next 168 hours.

Capacity Transfers and External Assistance

ERCOT has coordination plans in place with neighboring grids. These plans cover dc tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers.

Transmission

ERCOT completed its 2022 Regional Transmission Plan in December 2022. The plan lists 15 major reliability improvement projects out of a total of 89 proposed projects. Currently, there are $10.26 billion of transmission improvement projects that are expected to be put in service between 2023 and the end of 2028.

In November 2022, the PUCT amended rules to establish a congestion cost savings test for evaluating economic transmission projects; to require FERC to consider historical load, forecasted load growth, and additional load seeking interconnection when evaluating the need for additional ERCOT reliability transmission projects; to provide exemptions to the certificate of convenience and necessity requirements for certain transmission projects; and to require ERCOT to conduct a biennial assessment of the ERCOT grid's reliability and resiliency in extreme weather conditions. The rule will also allow the PUCT to consider the resiliency benefits of proposed transmission projects as determined by ERCOT's new biennial assessment when determining whether to approve a project. ERCOT has begun implementing the amended rules, including the evaluation of economic projects based on the new criteria using the 2022 RTP economic cases.

Other Reliability Issues

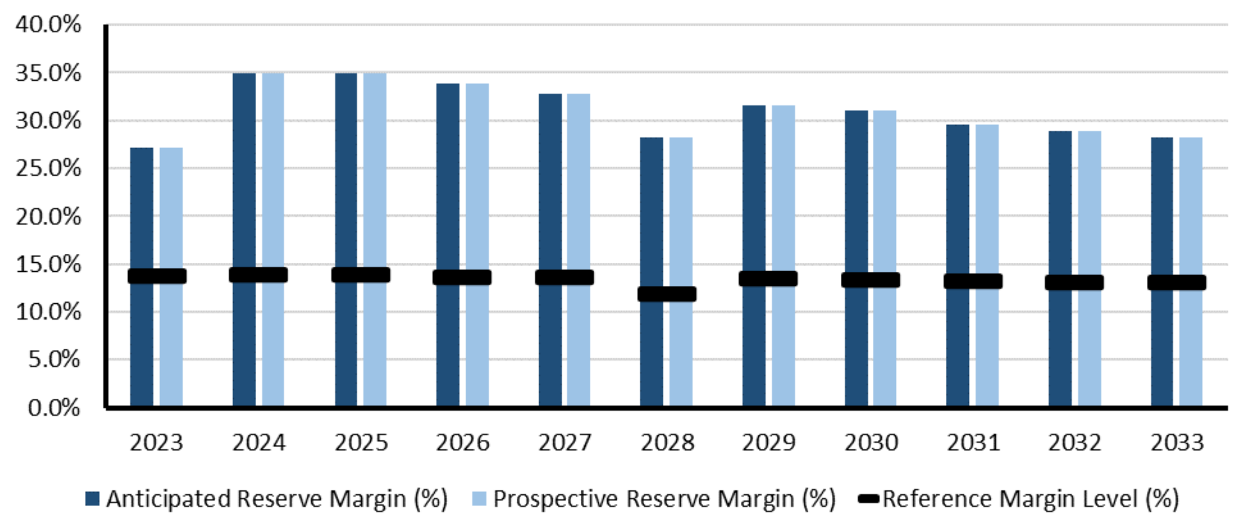
Several proposed rules and rule changes by the U.S. EPA heighten the risk of thermal unit retirements occurring after 2023. ERCOT is working with Generation Owners and state regulators to assess how these rules could impact grid reliability. Unless appropriate reliability safeguards are put in place, there is a risk of regional reliability issues developing, such as overloads on multiple transmission elements as well as the risk of a broader system-wide resource adequacy problem.

WECC-AB

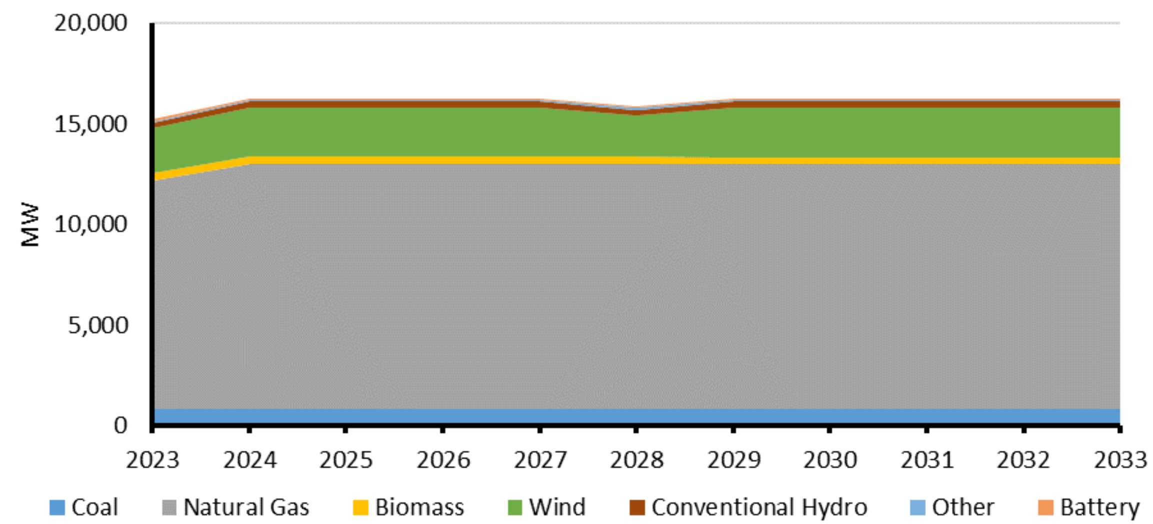
WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 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. See Normal Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	12,065	12,065	12,154	12,257	12,373	12,362	12,413	12,548	12,622	12,689
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,065	12,065	12,154	12,257	12,373	12,362	12,413	12,548	12,622	12,689
Additions: Tier 1	2,579	2,579	2,579	2,579	2,437	2,578	2,578	2,578	2,578	2,578
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	1,350	1,771	2,088	2,216	2,187	2,433	2,525	2,579	2,647	2,700
Net Firm Capacity Transfers	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	13,694	13,694	13,694	13,694	13,435	13,687	13,687	13,687	13,687	13,687
Anticipated Reserve Margin (%)	34.9%	34.9%	33.9%	32.8%	28.3%	31.6%	31.0%	29.6%	28.9%	28.2%
Prospective Reserve Margin (%)	34.9%	34.9%	33.9%	32.8%	28.3%	31.6%	31.0%	29.6%	28.9%	28.2%
Reference Margin Level (%)	13.9%	13.8%	13.7%	13.6%	11.9%	13.4%	13.4%	13.2%	13.1%	13.1%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML.
- Alberta shows the lowest growth rate in the West. The peak hour demand for the Alberta subregion occurs in the winter. The subregion is expected to grow from about 11.9 GW in 2023 to 12.6 GW in 2033, a 6.1% cumulative load growth over the assessment period, or a 0.78% annualized average rate. There was almost no change to the load forecast for this year's plan from last year.
- Several near-term 2023 transmission projects are planned for reliability and economics/congestion. The Provost to Edgerton and Nilrem to Vermilion project is delayed.

Note: the table below reflects the expected 50th percentile, or a 50% probability of energy availability by resource type on the peak hour.

WECC-AB Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	800	800	800	800	800	800	800	800	800	800
Natural Gas	12,211	12,211	12,211	12,211	12,211	12,204	12,204	12,204	12,204	12,204
Biomass	336	336	336	336	336	336	336	336	336	336
Wind	2,472	2,472	2,472	2,472	2,054	2,472	2,472	2,472	2,472	2,472
Conventional Hydro	285	285	285	285	301	285	285	285	285	285
Other	81	81	81	81	81	81	81	81	81	81
Battery	88	88	88	88	88	88	88	88	88	88
Total MW	16,273	16,273	16,273	16,273	15,872	16,265	16,265	16,265	16,265	16,265

WECC-AB Assessment

Planning Reserve Margins

The ARM does not fall below the reference margin. The 2024 operable on-peak margin has grown slightly to 26.1% from 22.4% in the last assessment.

Energy Assessment and Non-Peak Hour Risk

WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing the probability metrics used for assessing demand and variable resource availability in every hour.

WECC performs energy-based probabilistic assessments based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. For this reason, WECC does not perform calculations for capacity contributions for VERs or other types of resources, seasonally or otherwise. Similarly, duration is not assumed for storage resources. WECC is still looking at ways of improving BESS modeling.

For variable resources, WECC uses historical hourly generation data to develop expected capacity contributions and the associated probability distributions around the expected capacity contribution on an hourly basis. This is consistent with how the same information was calculated in previous assessments. For the purposes of the LTRA, the expected 50th percentile of the probability density functions is used as the most likely energy contribution from each resource type. For the ProbA, the entire probability density functions are used with the associated probabilities of occurrence. The contributions for all resource types are calculated on a localized, BA footprint. Therefore, solar behavior in one balancing area may not reflect the expected contribution of solar in another balancing area.

Probabilistic Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	-	-	-
EUE (PPM)	-	-	-
LOLH (hours per Year)	-	-	-
Operable On-Peak Margin	22.4%	26.1%	33.9%

*Provides the 2022 ProbA Results for Comparison

Demand

The peak hour of demand for Alberta occurs in winter in late December around 6:00 p.m. The subregion is expected to grow from about 11.9 GW in 2023 to 12.6 GW in 2033, a 6.1% cumulative load growth over the assessment period, or 0.78% annualized average rate. There was almost no change to the load forecast for this year's plan. Alberta continues to show the lowest growth rate in WECC.

Alberta produces hourly load projections for 20 years with historical load and real GDP, population, employment, oil sands production, gas production, meteorological inputs, and key load impacting events (e.g., past wildfires) in its demand forecasting. The forecast considers transportation electrification and DERs. The next assessment is expected to reflect more explicit modelling of EE, building and industry electrification, and EV charging profiles in the forecast. They incorporate the impact of temperatures on the efficiency of engines and BESS and the unique driving range needs depending on the day of the week.

Demand-Side Management

WECC-AB reported no controllable and dispatchable DR; however, programs are market driven and can be called upon for economic consideration in the AESO area.

Distributed Energy Resources

Alberta has 3,619 MW of existing nameplate wind and 1,165 MW of solar PV. 4,041 MW of wind and 3,310 MW of solar PV are planned. Solar PV is expected to grow at a CAGR of 7.3% while wind capacity is planned to grow at 3.11% and BESS at 2.77%. These rates will lead to a doubling of solar PV, a 40% increase in wind, and a 35% increase in BESS by 2033. BTM resources are netted with load. The renewable resources will be supported by 205 MW of BESS.

Generation

Highlights of Alberta's resource portfolio include almost 800 MW of coal, 11 GW of natural gas (increasing to 16 GW by the end of 2039), and almost 900 MW of conventional hydrogeneration. Almost 800 MW of hydro was built before 1972. No hydro units have retirement dates planned. Alberta has a 30% by 2030 clean energy target.

Energy Storage

Alberta has 90 MW of energy storage and plans to add 105 MW more by 2039, 45 MW of which will be in the next 10 years.

Capacity Transfers and External Assistance

No firm imports are shown to be needed in the model.

Transmission

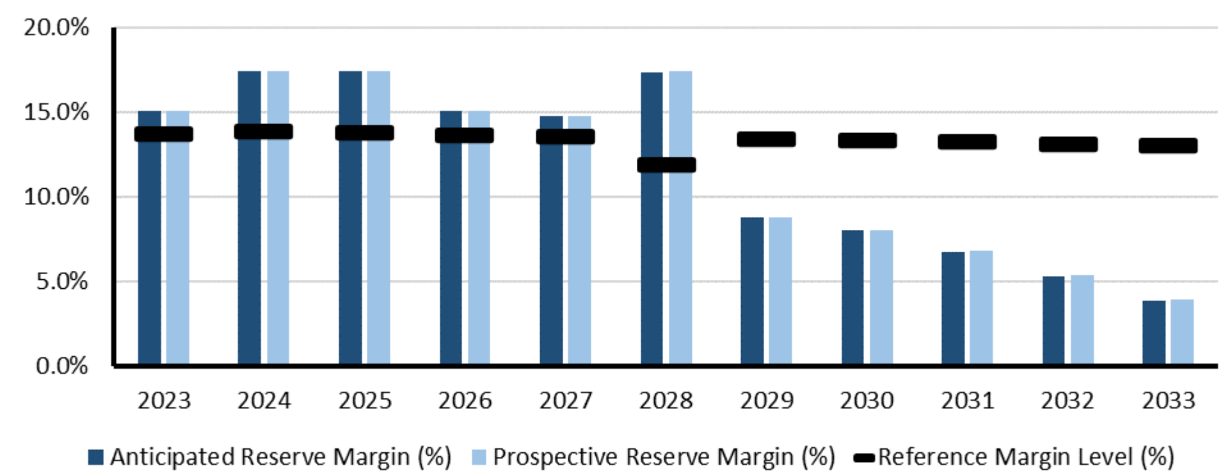
Several near-term 2023 transmission projects are planned for reliability and economics/congestion, covering over 330 miles, and two of which are 400+ kV lines. The Provost to Edgerton and Nilrem to Vermilion project is delayed.

WECC-BC

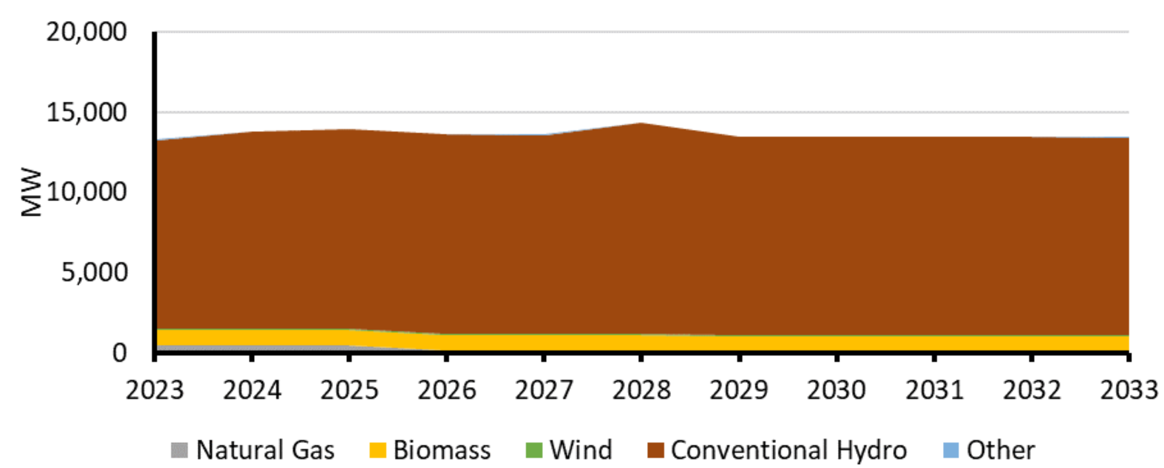
WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 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. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	11,786	11,897	12,031	12,159	12,270	12,389	12,511	12,657	12,799	12,943
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,786	11,897	12,031	12,159	12,270	12,389	12,511	12,657	12,799	12,943
Additions: Tier 1	672	806	806	1,158	1,627	1,561	1,599	1,599	1,913	2,226
Additions: Tier 2	0	0	0	4	4	4	4	4	4	4
Additions: Tier 3	0	0	2	44	46	44	44	95	95	95
Net Firm Capacity Transfers	0	0	198	334	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	13,166	13,166	13,043	12,799	12,774	11,915	11,915	11,915	11,568	11,220
Anticipated Reserve Margin (%)	17.4%	17.4%	15.1%	14.8%	17.4%	8.8%	8.0%	6.8%	5.3%	3.9%
Prospective Reserve Margin (%)	17.4%	17.4%	15.1%	14.8%	17.4%	8.8%	8.1%	6.8%	5.4%	3.9%
Reference Margin Level (%)	13.9%	13.8%	13.7%	13.6%	11.9%	13.4%	13.4%	13.2%	13.1%	13.1%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML for the peak hour starting in winter 2029–2030.
- BC Planning Reserve Margins are below the RML from December 2029 through the remainder of this assessment period. BC shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new solar PV or conventional hydrogeneration resources were to be delayed. BC is retiring 400 MW of natural gas and refurbishing significant amounts of hydrogeneration that come off-line for about a year.
- The peak hour demand for the BC subregion occurs in the winter. The subregion is expected to grow from about 11.6 GW in 2023 to 12.9 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast and an 11.4% load growth over the assessment period, or 1.07% annualized average rate.
- BC is showing hours of demand at risk that are not fully mitigated by the addition of Tier 3 resources.

Note: the table below reflects the expected 50th percentile, or a 50% probability of energy availability by resource type on the peak hour.

WECC-BC Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Natural Gas	457	457	170	170	170	61	61	61	61	61
Biomass	944	944	944	944	944	938	938	938	938	938
Wind	111	111	111	111	81	111	111	111	111	111
Conventional Hydro	12,303	12,437	12,404	12,375	13,184	12,343	12,382	12,382	12,347	12,313
Other	22	22	22	22	22	22	22	22	22	22
Total MW	13,837	13,972	13,651	13,623	14,401	13,476	13,514	13,514	13,480	13,446

WECC-BC Assessment

Planning Reserve Margins
For the peak hour, the ARM and PRM fall below the RML starting in winter 2029–2030. BC shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new solar PV or conventional hydrogeneration resources were to be delayed. BC is retiring 400 MW of natural gas and refurbishing significant amounts of hydrogeneration that come offline for about a year.

Energy Assessment and Non-Peak Hour Risk
WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

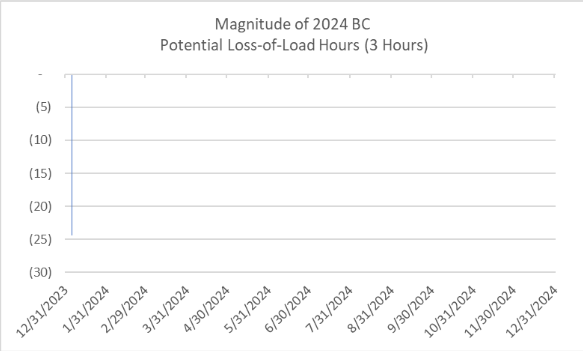
WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing, Tier 1 and Tier 2 resources, BC shows three potential loss-of-load hours in 2024 and 2025 and 31 om 2026:

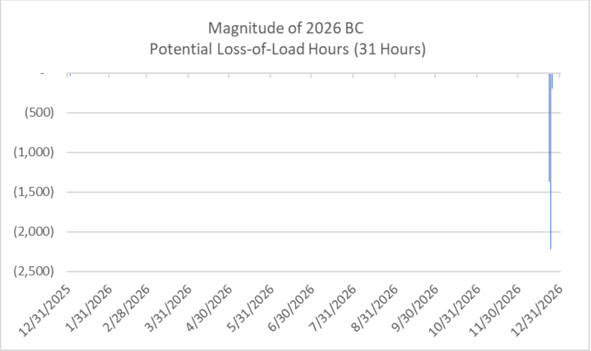
Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	24	47	15,991
EUE (PPM)	0.370	0.71	238
LOLH (hours per Year)	0.002	0.002	0.749
Operable On-Peak Margin	18.5%	12.7%	10.7%

*Provides the 2022 ProbA Results for Comparison

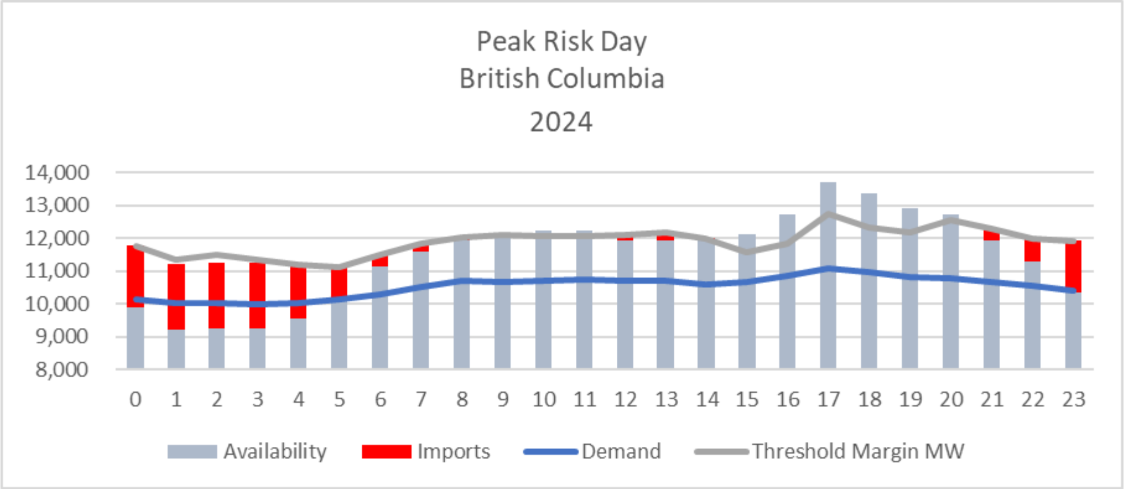
Probabilistic Assessments
WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the 1-day-in-10-year level, meaning that 99.98% of the demand for each hour is covered by available resources, i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour.

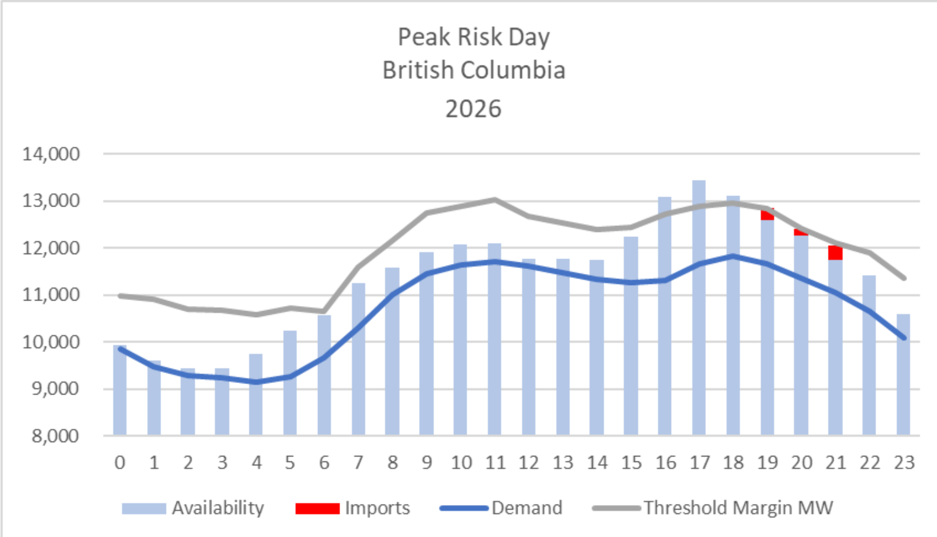
The following plots are outputs from WECC's probabilistic assessment and show the distribution of load loss events in MW across the study years 2024 and 2026.





The following plots are outputs from WECC's probabilistic assessment and show the modeled demand and resources on the peak demand day for 2024 and 2026.





Demand

The peak hour of demand for BC occurs in the winter in late December around 6:00 p.m. The subregion is expected to grow from about 11.6 GW in 2023 to 12.9 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast and an 11.4% load growth over this assessment period, or 1.07% annualized average rate.

Demand-Side Management

No controllable or DR program capacities were reported.

Distributed Energy Resources

BTM resources are netted with load. BC has 2 MW of existing solar PV and 30 MW planned, half in 2023 and half in 2027. BC has 15 MW of new wind planned in 2026 to add to its existing portfolio of 747 MW of wind capacity.

Generation

British Columbia is 95% carbon-free today. Its *CleanBC Roadmap to 2030* states, "By 2030, BC will phase out BC Hydro's last gas-powered facility so the electricity we make is 100% clean." In 2023, BC has 462 MW of natural gas, 17 MW of landfill gas, and 143 MW of black liquor fuel. Confirmed retirements increased through 2033 by 1 GW from the last assessment.

Energy Storage

No BESS projects are planned. BC has plentiful hydrogeneration energy storage resources.

Capacity Transfers and External Assistance

BC shows a small amount of import growth in winter 2023–2024 (110 MW), 2026–2027 (198 MW), and 2027–2028 (334) compared to none in last year's result.

Transmission

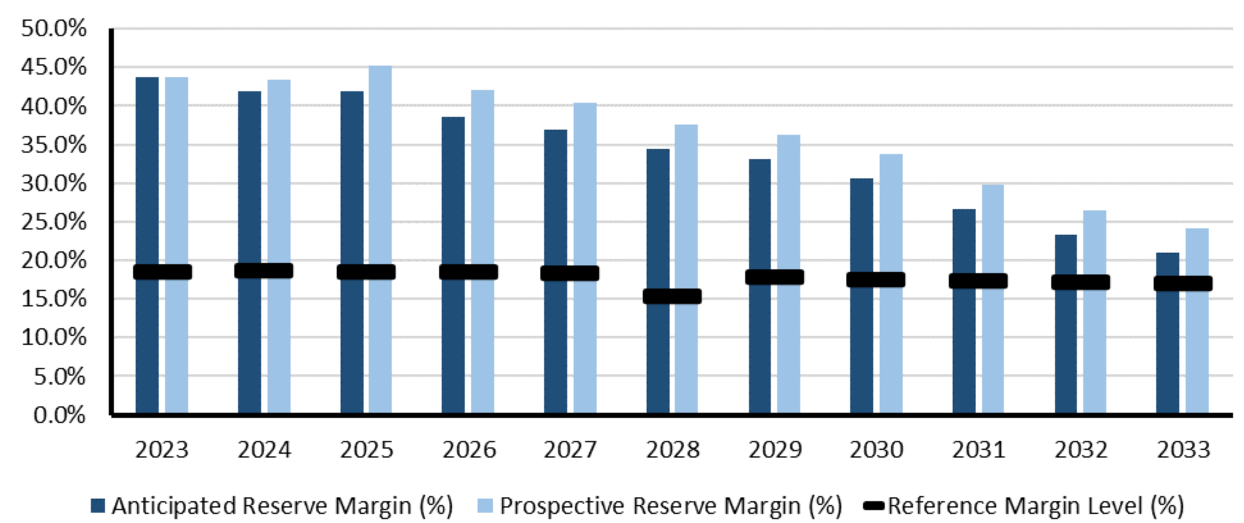
Out of 12 projects, 6 are planned with voltage design of 500 kV and higher in BC. The primary drivers are economics / congestion and reliability. There are also three conceptual projects for 200–299 kV lines for downtown Vancouver.

WECC-CA/MX

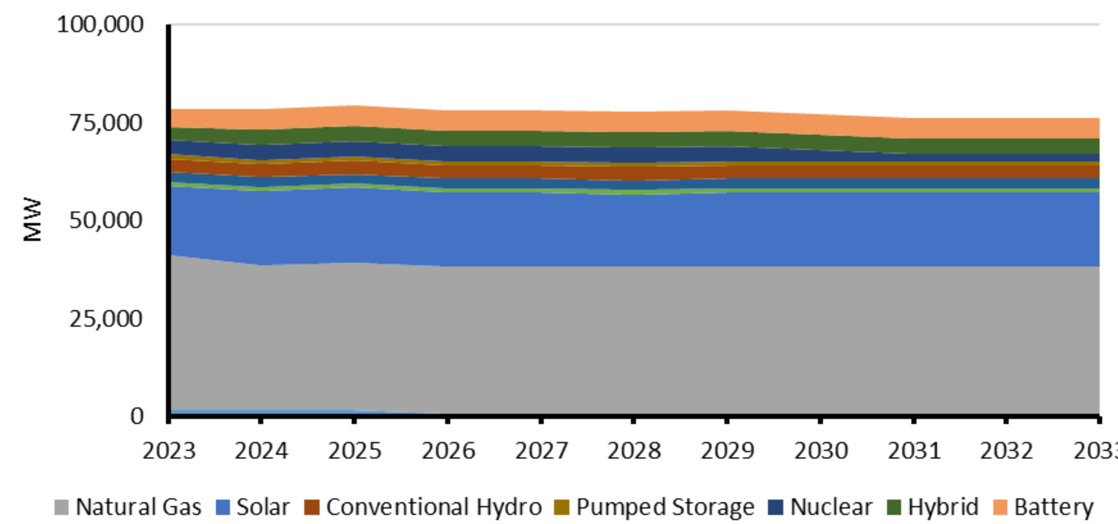
WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorizes, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 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. See **Elevated Risk Areas** for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	57,178	57,884	58,554	59,380	60,294	61,180	62,213	63,418	64,470	65,449
Demand Response	829	836	841	852	855	866	872	878	883	883
Net Internal Demand	56,349	57,048	57,712	58,529	59,439	60,313	61,341	62,540	63,587	64,566
Additions: Tier 1	10,859	11,771	11,790	11,810	11,610	11,822	11,830	11,830	11,830	11,830
Additions: Tier 2	828	1,964	1,964	1,964	1,932	1,964	1,964	1,964	1,964	1,964
Additions: Tier 3	232	1,957	2,198	3,212	3,316	3,419	3,723	23,547	23,547	23,547
Net Firm Capacity Transfers	0	0	161	338	521	408	1,339	1,572	808	530
Existing-Certain and Net Firm Transfers	69,136	69,136	68,189	68,366	68,281	68,418	68,245	67,374	66,610	66,332
Anticipated Reserve Margin (%)	41.96%	41.82%	38.58%	36.99%	34.41%	33.04%	30.54%	26.65%	23.36%	21.06%
Prospective Reserve Margin (%)	43.43%	45.27%	41.99%	40.34%	37.66%	36.30%	33.74%	29.79%	26.45%	24.10%
Reference Margin Level (%)	18.64%	18.54%	18.42%	18.26%	15.28%	17.81%	17.58%	17.34%	17.17%	17.01%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the reference margin on the peak hour; however, CA/MX shows increasing EUE and LOLH over this assessment period, including 19 hours at risk in 2026 that are not fully mitigated by the addition of Tier 3 resources.
- The ARM falls below the RML in summer of 2027 but is covered by additional resources under the PRM if all 3,212 MW come on-line on time. Starting in summer 2024 onwards, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new resources were to be significantly delayed.
- The peak hour demand for the CA/MX subregion occurs in the summer. The subregion is expected to grow from about 55.5 GW in 2023 to 64.6 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast in the long-term but a lower forecast through 2028. This represents a 16.3% load growth over this assessment period, or a 1.52% annualized average rate.
- 16 GW of energy storage is planned, and CA/MX has 2.8 GW of natural gas planned for retirement by the end of 2023, 1.2 GW of coal in 2025, and 2.3 GW of nuclear by the end of 2030.

Note: the table below reflects the expected 50th percentile, or 1 in 2 probability of energy availability by resource type on the peak hour.

WECC-CA/MX Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	1,595	1,595	487	487	487	487	487	487	487	487
Petroleum	761	761	761	761	761	757	757	757	757	757
Natural Gas	36,884	37,644	37,644	37,644	37,644	37,639	37,639	37,639	37,639	37,639
Biomass	777	777	777	777	777	775	775	775	775	775
Solar	19,095	19,112	19,130	19,150	18,317	19,166	19,174	19,174	19,174	19,174
Wind	994	994	994	994	1,354	994	994	994	994	994
Geothermal	2,434	2,434	2,434	2,434	2,434	2,428	2,428	2,428	2,428	2,428
Conventional Hydro	3,453	3,453	3,453	3,453	3,495	3,453	3,453	3,453	3,453	3,453
Pumped Storage	1,034	1,034	1,034	1,034	1,057	1,034	1,034	1,034	1,034	1,034
Nuclear	3,880	3,880	3,880	3,880	3,880	3,874	2,770	1,667	1,667	1,667
Hybrid	3,942	3,942	3,942	3,942	3,882	3,940	3,940	3,940	3,940	3,940
Other	29	29	29	29	29	29	29	29	29	29
Battery	5,117	5,252	5,252	5,252	5,252	5,256	5,256	5,256	5,256	5,256
Total MW	79,995	80,908	79,818	79,839	79,370	79,832	78,736	77,632	77,632	77,632

WECC-CA/MX Assessment

Planning Reserve Margins
The reserve margins would fall below the RML in summer of 2027 without Tier 1 resources (3,212 MW) coming on-line. Starting in summer 2024 onwards, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new resources were to be significantly delayed.

Energy Assessment and Non-Peak Hour Risk
WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

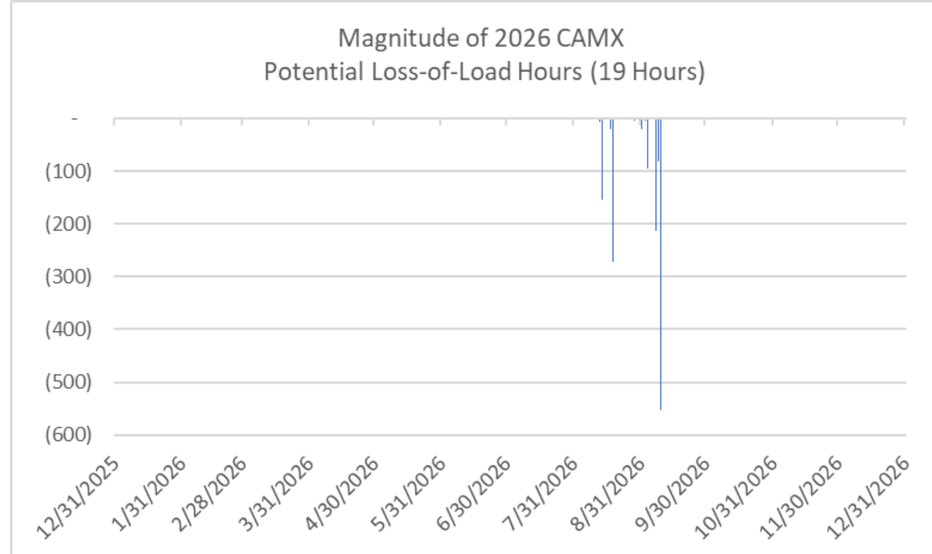
WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing, Tier 1 and Tier 2 resources, CA/MX shows 19 potential loss-of-load hours in 2026:

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	37,305	-	11,731
EUE (PPM)	136	-	43
LOLH (hours per Year)	0.721	-	0.227
Operable On-Peak Margin	30.3%	30.7%	27.5%

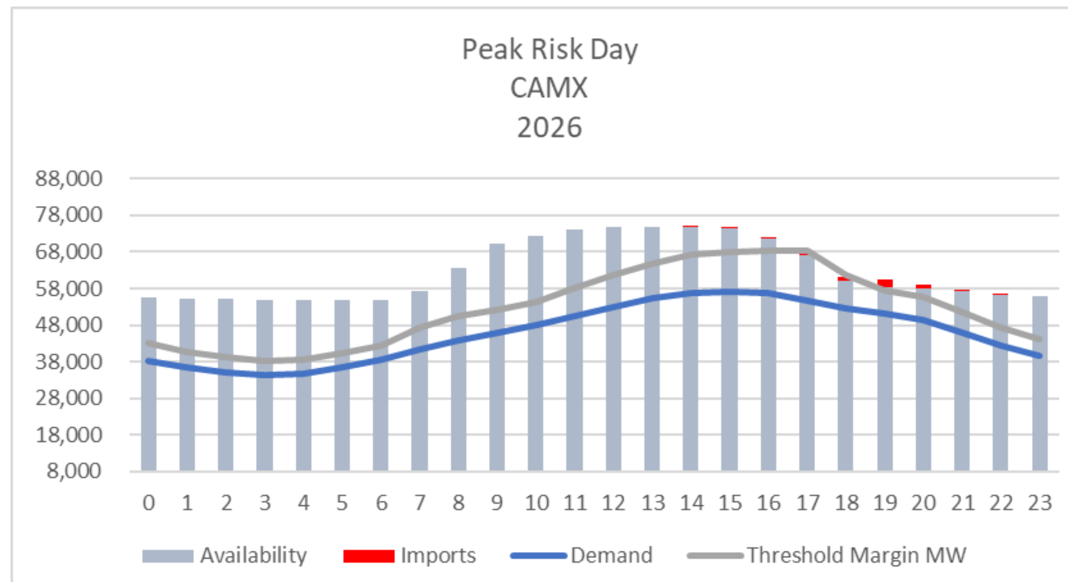
* Provides the 2022 ProbA Results for Comparison

Probabilistic Assessments
WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the 1-day-in-10-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

The following plot is output from WECC's probabilistic assessment and shows the distribution of load loss events in MW across the 2026 study year.



The following plot is output from WECC's probabilistic assessment and shows the modeled demand and resources on the peak demand day for 2026.



Demand

The peak hour demand for the CA/MX subregion occurs in the summer around the second week of September at 3:00 p.m. The subregion is expected to grow from about 55.5 GW in 2023 to 64.6 GW in 2033, a slight (average CAGR of 0.25%) increase from the last forecast in the long-term but a lower forecast through 2028. This represents a 16.3% load growth over this assessment period, or 1.52% annualized average rate.

Load forecasts are developed by correlation with econometric and demographic factors. In CA/MX, these include population, households, personal income, energy rates, commercial floorspace, employment, and precipitation. For transportation, vehicle attributes, fuel prices, incentives, vehicle miles traveled, duty cycle, and consumer preference surveys contribute to analyses.

Existing electrification is captured through building surveys and DMV vehicle registration data. Multiple scenarios are designed for both vehicle and building electrification to reflect a variety of state and local ordinances.

There are local policies that have taken effect since the last assessment, driving building electrification. Examples include the following:

- Sacramento's All-Electric Only ordinance that went into effect January 1, 2023, for all new construction under three stories and all new construction regardless of height in 2026.
- San Luis Obispo passed an All-Electric Only ordinance for all new construction with an exception for certain natural gas end uses through 2025 if no all-electric alternative is commercially available or viable (for commercial kitchens, ADU water or space heating and for public swimming pools)
- Pasadena passed an All-Electric Only ordinance for new construction (or 50%+ renovations) multifamily, nonresidential and mixed-use buildings with exceptions for ADUs, commercial kitchens, and essential buildings (defined as medical healthcare facilities and research and development labs).

For a full list of electrification measures reflected in zero emission building ordinances, visit the Building Decarbonization Website.[56]

Additionally, there are transportation electrification goals in place to increase the number of EVs. The California Air Resources Board is regulating all new consumer vehicles sold to produce zero emissions by 2035. Seventeen other states adopted similar rules. The California Energy Commission (CEC) provided a calculator to estimate high, low, and expected impact levels by assuming various levels of meeting the targets of Executive Order B-48-18.

Demand-Side Management

CA/MX DSM is expected to grow from 829 MW in summer 2024 to 883 MW in summer 2033. In addition to the controllable and dispatchable programs, voluntary conservation has played a significant role during extreme events. During the widespread heatwave in 2020, demand reductions of approximately five GW were realized, exceeding the amounts available from dispatchable and controllable programs. For comparison, during the 2022 heat event, demand reductions were approximately 1,900 MW, reflecting the reduced geographic area of that event.

The CEC is utilizing the federal Inflation Reduction Act to provide funding for whole house EE. For low to moderate income households, it will also fund point of sale rebates for panel upgrades and qualified high-efficiency electric appliances, such as heat pumps for space heating and cooling. The programs will launch in 2024.

Some areas reported unavailable capacity when connecting new customer or upgrading service along with delays receiving the equipment, such as switchboards and switchgears, needed to connect new electrical services.

Distributed Energy Resources

BTM resources are netted with load. Utility distribution companies are required under Title 20 to report location, capacity, and technology type to the CEC for all interconnected systems, including BTM. Owners of systems larger than one MW must also report generation. Generation for smaller, less than one MW systems is either modeled according to capacity or purchased from third-party vendors.

One area adopted a bass diffusion model to estimate the rooftop PV impact to system load in terms of annual capacity and energy, capturing all BTM installations.

California changed its net metering tariff to a net billing tariff in 2023. This is expected to create a drag on BTM solar PV installations in the near term due in large part to the increased payback period for the investment. California has accounted for the largest share of BTM solar PV in WECC.

[56] **Building Decarbonization**

Generation

CA/MX has almost three GW of natural gas planned for retirement by the end of 2023, over one GW of coal in 2025, and 2.3 GW of nuclear by the end of 2030. In total, almost six and a half GW of coal, nuclear, and natural gas are planned to be retired by 2030. This is offset by 2.8 GW of planned new natural gas, 665 MW of geothermal, 644 MW of petroleum, 627 MW of pumped storage, 35 MW of new conventional hydro, and 55 MW of biomass capacity.

There are several renewable portfolio or carbon-free electricity targets in CA/MX that contribute to a changing resource mix. For example, the electric system operator in Mexico, CENACE, is aiming for 35% by 2025–2029 and California for 60% by 2030.

Coal deliveries were reduced for one area for the past two years, resulting in a reduction of available generation capacity for the foreseeable future. The area has implemented a fuel rationing procedure to maximize coal inventories.

Supply chain issues continue to be a major factor affecting the delivery of new resources, such as utility-scale solar PV and transmission line upgrades. These supply chain issues along with the increased costs of component suppliers have resulted in the need for renegotiations. Balancing areas report developers are seeing a 75-to-80-week delivery time for transformers and circuit breaker equipment compared to the typical 24 weeks prior to Covid-19. PV module deliveries have been significantly delayed for utility-scale solar PV projects. For example, the deliveries of solar modules delayed one very large multi-hundred MW project by 12 months.

Energy Storage

CA/MX is planning on adding 16 GW of energy storage to its almost three GW of existing energy storage, 6.6 GW of which are planned by the end of 2025.

Capacity Transfers and External Assistance

The summer imports through 2029 and compared to last year are decreasing, then increasing 2030 onwards. Winter firm imports are slightly above last year’s results (ranging from 240–632 MW).

Transmission

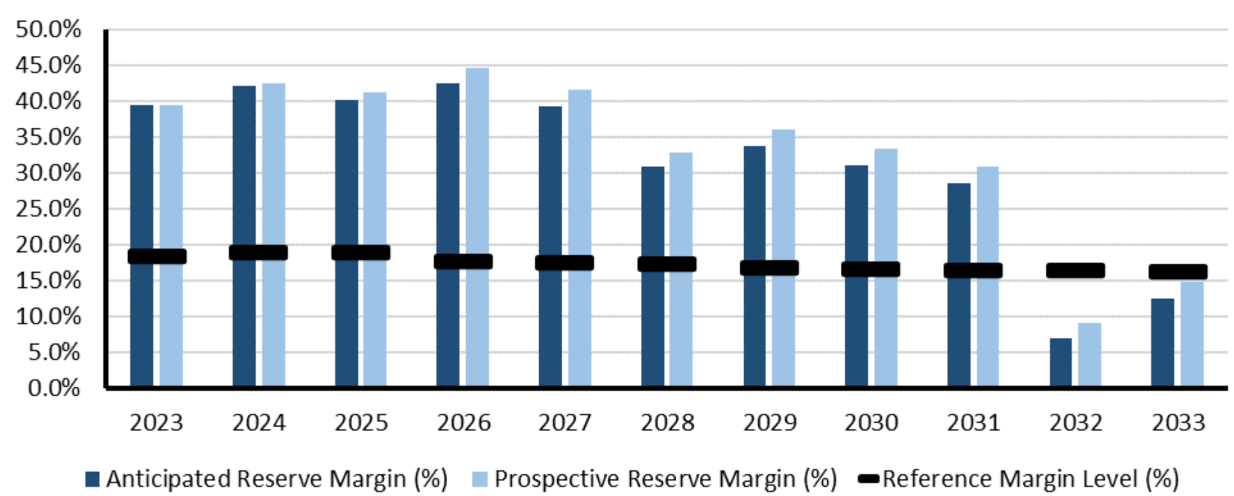
There are 10 planned and 2 conceptual projects with voltage designs of 500 kV and higher in CA/MX, representing a total addition of more than 1,000 miles. A diverse set of 3 conceptual projects spanning 160 miles, driven primarily by economics, congestion, and reliability needs are also in the works. There are 75 projects outside of the conceptual phase and in planning for almost 1,600 miles, plus 6 projects under construction for 35 miles.

WECC-NW

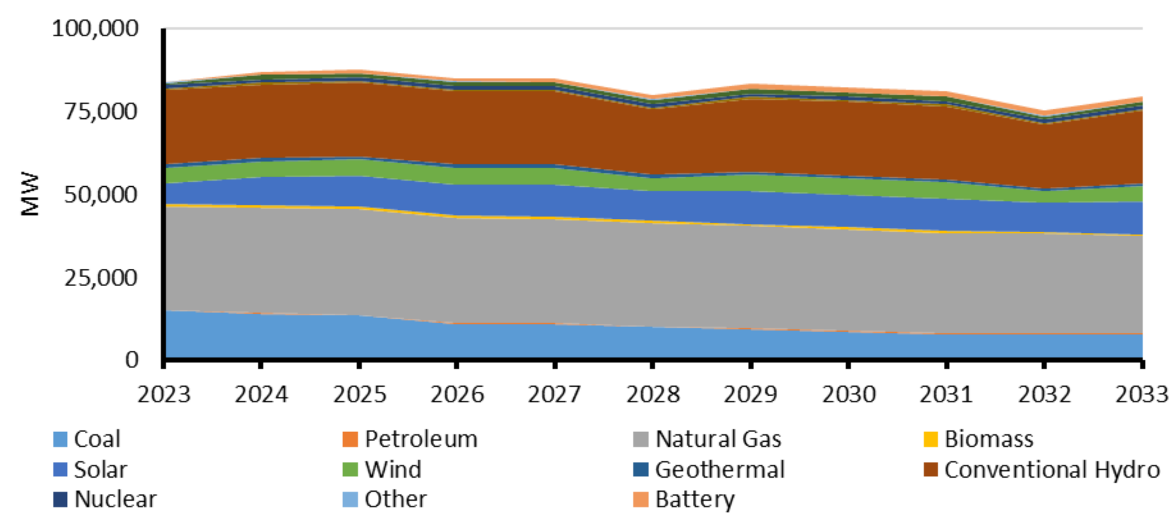
WECC-NW (Northwest) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 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. See Elevated Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	62,899	64,432	65,427	67,732	69,449	70,241	70,881	71,453	73,043	73,661
Demand Response	902	912	917	929	947	955	965	976	872	881
Net Internal Demand	61,997	63,520	64,510	66,803	68,502	69,286	69,916	70,477	72,171	72,780
Additions: Tier 1	7,190	8,450	8,846	9,020	8,938	9,691	9,746	9,801	9,303	9,895
Additions: Tier 2	229	671	1,351	1,463	1,365	1,611	1,628	1,628	1,502	1,645
Additions: Tier 3	676	2,131	3,798	3,865	5,820	7,403	8,994	9,889	10,468	11,898
Net Firm Capacity Transfers	1,157	1,290	6,785	8,002	9,826	9,255	9,293	9,383	1,957	2,103
Existing-Certain and Net Firm Transfers	80,900	80,584	83,100	84,066	80,760	83,028	81,942	80,831	67,904	71,957
Anticipated Reserve Margin (%)	42.1%	40.2%	42.5%	39.3%	30.9%	33.8%	31.1%	28.6%	7.0%	12.5%
Prospective Reserve Margin (%)	42.5%	41.2%	44.6%	41.5%	32.9%	36.1%	33.5%	30.9%	9.1%	14.7%
Reference Margin Level (%)	18.9%	18.9%	17.6%	17.6%	17.4%	16.8%	16.5%	16.4%	16.5%	16.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML for the peak hour starting in summer 2032.
- WECC-NW's demand-side management programs are expected to decline from 902 MW in summer 2024 to 881 in summer 2033 and grow from 584 in winter 2024, peaking in 2031 around 686 MW and then declining to 596 MW in winter 2033.
- Significant demand growth coupled with 19 GW of resources planned to retire from 2023 through 2034 are contributing to increasing loss-of-load hours over the planning period. There are several states in the WECC-NW renewable portfolio and carbon-free electricity targets driving the changes in resource portfolios in addition to a plethora of local building, transportation, and industrial electrification measures.

Note: the table below reflects the expected 50th percentile, or 1 in 2 probability of energy availability by resource type on the peak hour.

WECC-NW Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	13,883	13,450	10,834	10,834	9,961	9,272	8,631	7,675	7,678	7,675
Petroleum	285	285	285	285	285	279	279	279	280	279
Natural Gas	31,882	31,882	31,634	31,457	31,053	30,862	30,519	30,388	30,144	29,414
Biomass	775	773	767	737	731	671	671	671	669	656
Solar	8,373	9,130	9,492	9,660	8,877	9,883	9,883	9,815	8,622	9,767
Wind	4,864	5,077	5,065	5,065	4,119	5,058	5,037	4,998	3,779	4,928
Geothermal	910	892	926	890	905	858	740	740	670	467
Conventional Hydro	22,220	22,216	22,119	22,111	19,768	22,090	22,090	22,083	19,116	22,081
Pumped Storage	448	448	448	448	434	448	448	448	402	448
Nuclear	1,097	1,097	1,097	1,097	1,081	1,095	1,095	1,095	1,091	1,095
Hybrid	1,293	1,293	1,293	1,293	1,394	1,430	1,430	1,430	1,117	1,157
Other	78	78	78	78	78	77	77	77	78	77
Battery	824	1,124	1,124	1,129	1,186	1,440	1,495	1,550	1,605	1,705
Total MW	86,933	87,745	85,161	85,084	79,872	83,464	82,395	81,249	75,250	79,749

WECC-NW Assessment

Planning Reserve Margins

The ARM falls below the RML for the peak hour starting in summer 2032 and remains insufficient with the additional Tier 2 resources under the PRM following five GW planned for retirement between 2029 and 2032.

Energy Assessment and Non-Peak Hour Risk

WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing Tier 1 and Tier 2 resources, WECC-NW shows 28 potential loss-of-load hours in 2026, which falls to 15 hours at risk when Tier 3 resources are considered.

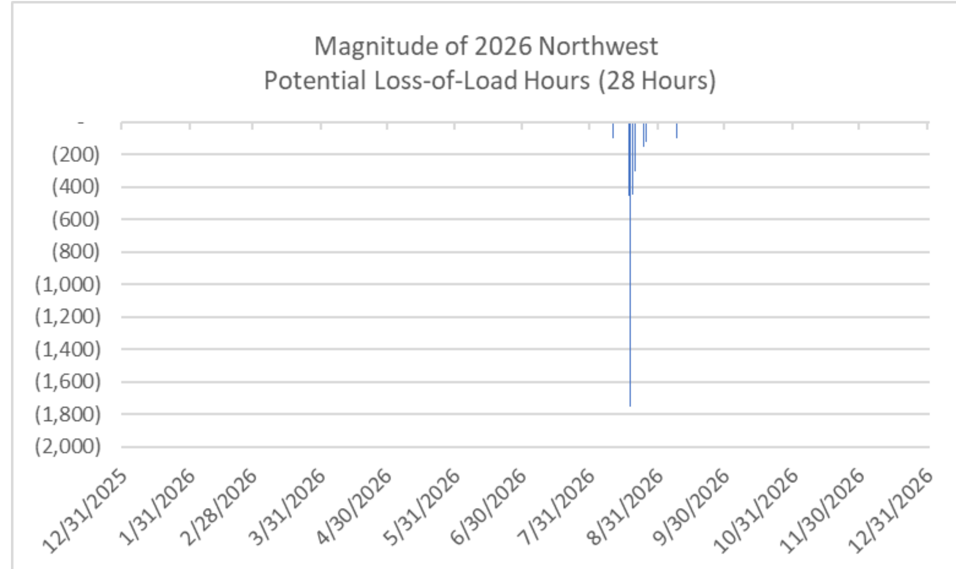
Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	1,722	-	8,101
EUE (PPM)	4	-	21
LOLH (hours per Year)	0.036	-	0.132
Operable On-Peak Margin	25.8%	37.6%	32.5%

* Provides the 2022 ProbA Results for Comparison

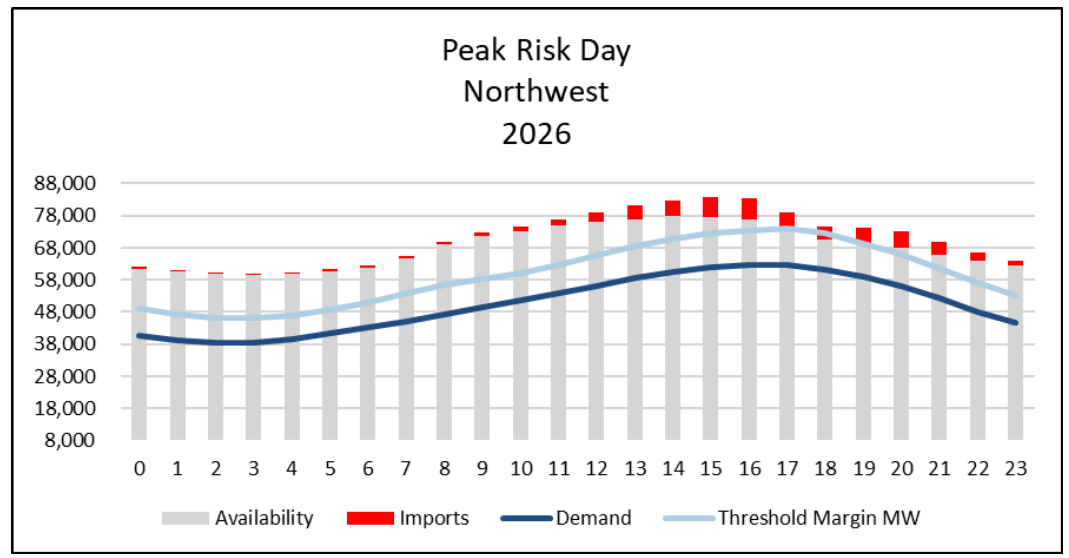
Probabilistic Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

The following plot is output from WECC's probabilistic assessment and shows the distribution of load loss events in MW across the 2026 study year.



The following plot is output from WECC's probabilistic assessment and shows the modeled demand and resources on the peak demand day for 2026.



Demand

The peak hour demand for WECC-NW occurs in the summer anywhere from mid-July to late-August around 4:00 p.m.. The subregion is expected to grow from about a 72 GW peak in 2023 to 84 GW in 2033; however, there are significant differences between balancing areas with some showing almost 50% growth compared to last year while others show slight shrinking load. This has been reported to be due to new data centers. This is contributing to some BAs showing a need for increased imports in the model compared to last year. This represents a nearly 17% load growth over this assessment period.

Additionally, there are transportation electrification goals in place to increase the number EVs. WECC-NW serves a portion of Northern California, where the California Air Resources Board is regulating all new consumer vehicles sold to produce zero emissions by 2035. Seventeen other states adopted similar rules. Oregon and Washington will ban the sale of new gas cars by 2035. ACEEE’s top three states in the 2023 Transportation Electrification Scorecard are California, Oregon, and Washington for planning and goal setting. The West dominates the top states supporting transportation transitions to electric vehicles with Colorado in 6th and Nevada tied for 12th.

Electrification assumptions are incorporated into the load projects for most areas in WECC-NW, including transportation, building, and some industrial. Several cities across the Northwest have implemented building electrification policies, including Salt Lake City, which has an all-electric requirement, and Park City, Utah, where there are programs that encourage the elimination of natural gas and propane with similar programs in Boulder and Superior, Colorado, respectively. Washington has both statewide and local electrification requirements.

Note that many balancing areas reported supply chain risks in WECC-NW. These include material delays, wires, and meters, causing a variety of projects to be postponed, including connecting new customers. A few said human resources (i.e., staffing) is an equally large problem.

Demand-Side Management

WECC-NW’s demand-side management programs are expected to decline from 902 MW in summer 2024 to 881 in summer 2033 and grow from 584 in winter 2024, peaking in 2031 around 686 MW and then declining to 596 MW in winter 2033.

Distributed Energy Resources

BTM resources are netted with load. Wind is expected to grow at CAGR of 2.65%, solar PV at 6.38%, BESS at 19.69% and hybrid resources at almost 28%. Existing solar PV accounts for eight GW of installed capacity and more than 10 GW of capacity are planned through 2033. Over 7.5 GW of wind is planned to be added through 2033 to the existing capacity of over 20 GW.

Generation

There are 19 GW of resources planned to retire from 2023 through 2034. This includes 128 MW of biomass, 8 GW of coal, over 6 GW of natural gas, and 6 MW of petroleum. There are several states in the WECC-NW with renewable portfolio and carbon-free electricity targets that are driving the changes in resource portfolios. These include Montana (15% 2015-19), Nevada (50% by 2030), Oregon (35% by 2030), and Washington state (greenhouse gases neutral with limited offsets by 2030).

Many balancing areas reported supply chain risks in WECC-NW. Supply chain issues are resulting in longer lead times for parts and equipment, delaying resource restoration after forced outages. The impact has been project schedules being extended to account for the procurement issues. Power circuit breaker lead times were being continually delayed. These issues are affecting all resources, both new facilities and updates to existing facilities. It is challenging to prioritize and schedule outages and decisions between stacking versus shifting.

The supply chain issues are expected to contribute to deviations from resource plans in the near term. For instance, solar PV panel supply chain issues have indefinitely postponed the incorporation of a new power supply resource that had been planned for January 2024.

Additionally, coal availability declined, and prices rose due to increased demand spurred by high natural gas prices and weather events. Those issues, combined with transportation constraints, resulted in lower availability. Supply chain issues limited coal inventory during peak hours of the day. This resulted in a new strategy for how units are scheduled on a day-ahead basis and how power is purchased in the real time markets.

Energy Storage

The NW is planning significant increases in BESS, including 425 MW in 2023, 680 MW in 2024, and another 1,130 MW through 2030. Existing BESS capacity is 172 MW.

Capacity Transfers and External Assistance

Significant increases from 1.6 GW to over 9 GW in the latter half of the forecast years compared to no year over 1 GW in the 2022 LTRA results.

Transmission

Four 500 kV and higher planned projects are in WECC-NW. Idaho Power’s new 300-mile Boardman-to-Hemingway 500 kV line, originally proposed in 2007 and projected to be in-service in 2013, has cleared its major regulatory requirements and should break ground this year or in 2024 and be energized as early as 2026.

The balancing areas in WECC-NW report supply chain delays to replace, upgrade, and expand transmission equipment, which has delayed project schedules. Transformer lead times reached three years. Breaker lead times were 85 weeks, or over a year and a half. Instrument transformers and other items were also experiencing much longer lead times, causing significant delays to project schedules.

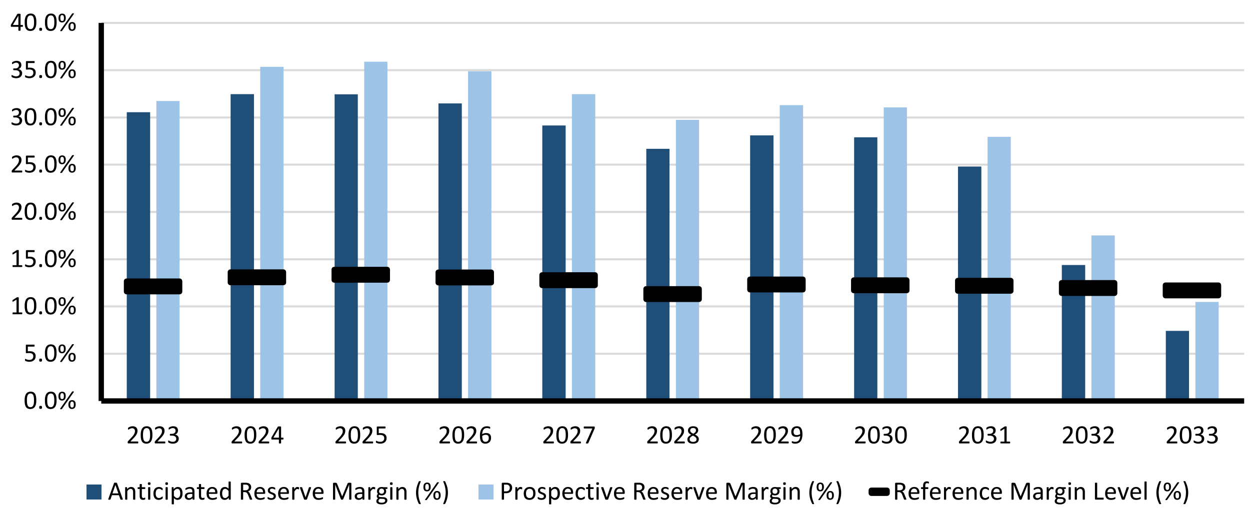
One key transmission risk is unusual outages scheduled during peak summer seasons that limit generation on baseloads, which can ultimately impact reliability.

WECC-SW

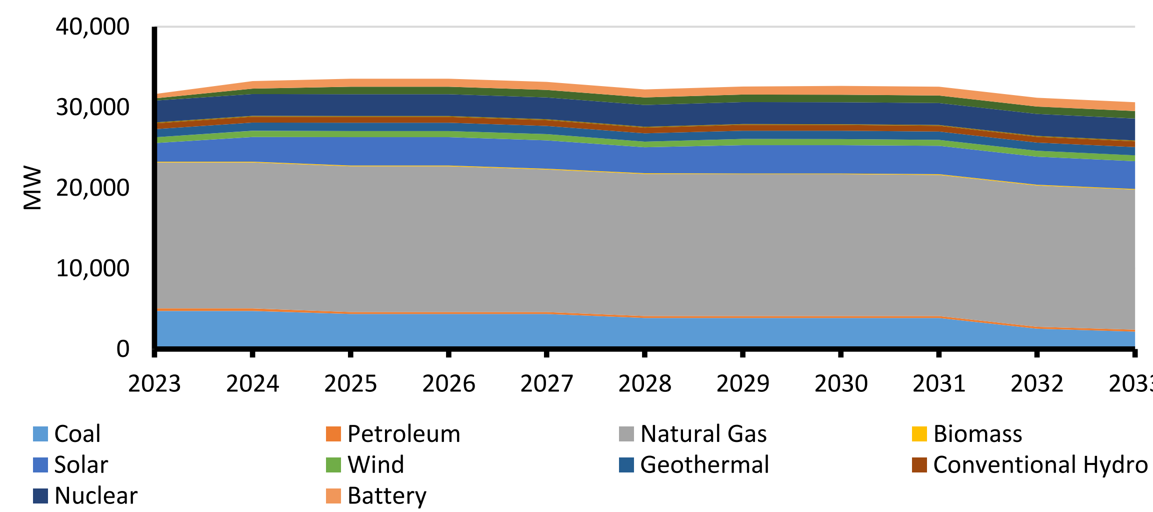
WECC-SW (Southwest) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 90 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. See Elevated Risk Areas for more details.

Demand, Resources, and Reserve Margins

Quantity	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Internal Demand	26,749	27,499	28,294	29,029	29,554	29,973	30,400	30,529	30,672	31,234
Demand Response	383	419	384	394	385	388	391	384	394	385
Net Internal Demand	26,366	27,080	27,910	28,635	29,169	29,585	30,009	30,145	30,278	30,848
Additions: Tier 1	3,441	4,217	4,217	4,217	4,046	4,219	4,308	4,308	4,308	4,308
Additions: Tier 2	764	937	948	948	894	948	948	948	948	948
Additions: Tier 3	947	2,074	4,593	4,938	5,081	5,861	6,511	7,277	8,489	8,697
Net Firm Capacity Transfers	1,676	2,316	3,148	3,824	4,731	5,324	5,736	5,072	3,448	2,512
Existing-Certain and Net Firm Transfers	31,484	31,648	32,480	32,765	32,905	33,678	34,075	33,313	30,327	28,828
Anticipated Reserve Margin (%)	32.5%	32.4%	31.5%	29.1%	26.7%	28.1%	27.9%	24.8%	14.4%	7.4%
Prospective Reserve Margin (%)	35.4%	35.9%	34.9%	32.5%	29.7%	31.3%	31.1%	27.9%	17.5%	10.5%
Reference Margin Level (%)	13.1%	13.4%	13.1%	12.8%	11.3%	12.3%	12.2%	12.2%	12.0%	11.7%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML for the peak hour until Summer 2033 when it shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new capacity were to be delayed.
- Looking at all hours, WECC-SW shows demand at risk starting in 2025 and increasing over this assessment period, which is slightly mitigated and delayed until 2027 with the consideration of on-time Tier 3 resource commissioning.

Note: the table below reflects the expected 50th percentile, or 1 in 2 probability of energy availability by resource type on the peak hour.

WECC-SW Fuel Composition										
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	4,724	4,354	4,354	4,354	3,859	3,852	3,852	3,852	2,527	2,159
Petroleum	318	241	241	241	241	241	241	241	241	241
Natural Gas	18,113	18,084	18,084	17,692	17,622	17,604	17,604	17,522	17,522	17,377
Biomass	94	94	94	94	94	94	94	94	94	94
Solar	3,063	3,517	3,517	3,517	3,222	3,517	3,517	3,516	3,493	3,442
Wind	770	770	770	770	708	770	756	741	727	727
Geothermal	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022	1,022
Conventional Hydro	719	719	719	719	701	719	719	719	719	719
Pumped Storage	110	110	110	110	113	110	110	110	110	110
Nuclear	2,714	2,714	2,714	2,714	2,714	2,717	2,717	2,717	2,717	2,717
Hybrid	668	929	929	929	929	930	930	930	930	930
Battery	933	995	995	995	995	996	1,085	1,085	1,085	1,085
Total MW	33,249	33,549	33,549	33,157	32,220	32,573	32,647	32,548	31,186	30,623

WECC-SW Assessment

Planning Reserve Margins
ARM and PRM fall below the RML on the peak hour in Summer 2033. Starting in summer 2033, WECC-SW shows a shortfall of existing-certain and net firm transfers, meaning imports may be necessary if new capacity were to be delayed.

Energy Assessment and Non-Peak Hour Risk
WECC uses the Multi-Area Variable Resource Integration Convolution model. The model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour.

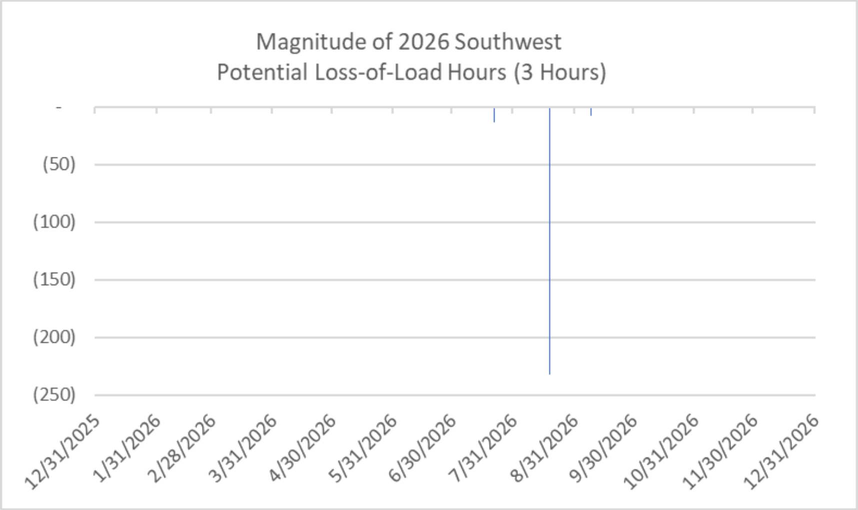
WECC performs energy-based probabilistic assessments that are based on distributions of resource availability and distributions of demand. For resources, WECC uses the 3rd to 97th percentiles of hourly availability. Looking at all hours of the year and counting existing, Tier 1 and Tier 2 resources, WECC-SW shows three potential loss-of-load hours in 2026, which falls to zero hours at risk when Tier 3 resources are considered.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	84	-	818
EUE (PPM)	1	-	6
LOLH (hours per Year)	0.003	-	0.031
Operable On-Peak Margin	28.1%	18.3%	18.4%

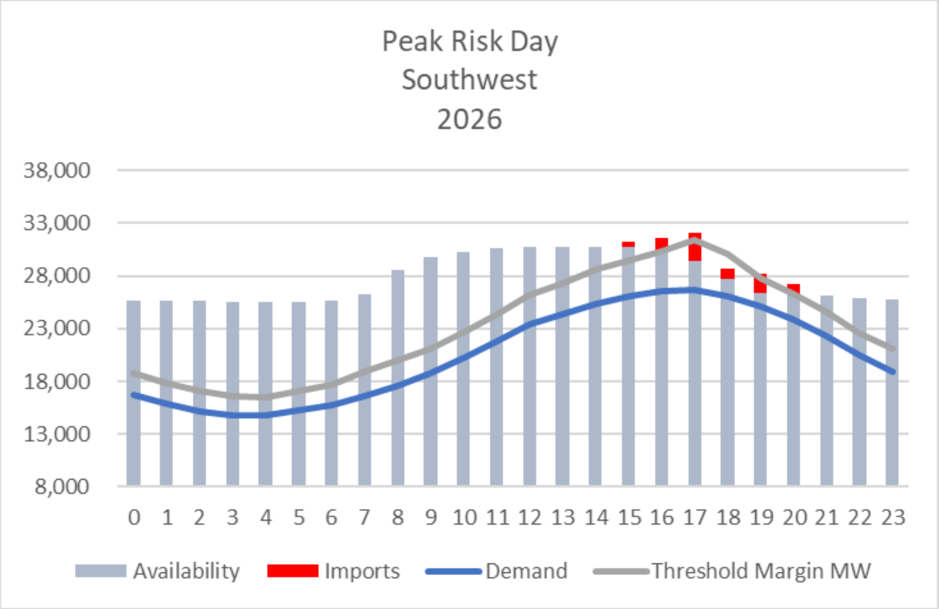
* Provides the 2022 ProbA Results for Comparison

Probabilistic Assessments
WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the 1-day-in-10-year level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than 0.02% of the total area of the demand curve for any given hour).

The following plot is output from WECC's probabilistic assessment and shows the distribution of load loss events in MW across the 2026 study year.



The following plot is output from WECC's probabilistic assessment and shows the modeled demand and resources on the peak demand day for 2026.



Demand

The Southwest's peak demand (summer) CAGR is 1.68%, WECC-SW load forecast is nearly the same as last year’s, a slight drop from last year’s 1.72%. Over the planning period, WECC-SW goes from a summer peak of almost 27 GW in 2023 to 33 GW by 2033 or 20% over this assessment year. WECC-SW peaks in mid-July around 5:00 p.m.

The load forecasts reflect different degrees of electrification. Most include transportation electrification assumptions, but few are incorporating building and industry electrification impacts. Data centers are another load compounding impact being studied.

Some areas have reported delays energizing customers due to supply chain issues. At times, material has not been available to complete some overhead services on schedule. Alternative design solutions have had to be explored. Due to the supply chain shortages, subdivision projects have been delayed. Chip shortages have impacted meter orders.

Demand-Side Management

WECC-SW summer demand-side management programs are expected to grow from 383 MW in 2024 to 385 MW in 2033 and from 288 MW in winter 2024 to 318 MW by winter 2033.

Distributed Energy Resources

BTM resources are netted with load.

Generation

WECC-SW is retiring 4.1 GW of capacity over this assessment period, which includes almost three GW of coal and 780 MW of natural gas. There are several states in WECC-SW with a renewable portfolio and carbon-free electricity targets driving the changes in resource portfolios. These include Arizona (15% 2025–2029), New Mexico (50% by 2030), and individual utility independent goals.

Almost 350 MW of new geothermal capacity is planned along with 1,230 MW of new natural gas by 2026. Additionally, over 15 GW of new solar PV is in the resource plans, almost 1,200 MW of wind.

Due to fuel shortfalls in 2022, some areas have revamped their communications to manage potential fuel shortages better proactively. Additionally, pipeline outages have been resolved and are now fully available.

Supply chain constraints are impacting WECC-SW. In response, procurement timelines have been accelerated to earlier in projects’ processes. Generator step-up transformers have a longer lead time than in prior years, impacting the commercial operation date of new resources in plans through 2026. New utility-scale renewable resource timing has been unstable due to raw material and earth metal accessibility.

Energy Storage

The SW has 3.7 GW of energy storage planned in addition to the existing capacity of 140 MW.

Capacity Transfers and External Assistance

The SW shows increasing firm imports in summer from 1.7 to 5.7 GW over the assessment period and none in winter. Some areas have reported system constraints that could be a future reliability risk for import transfer availability.

Transmission

There are five transmission projects with voltage design of 500 kV and higher planned in the Southwest. In addition, there are 37 conceptual projects to cover almost 250 miles, 43 planned projects for almost 350 miles, and six projects under construction covering 68 miles. The primary driver for a significant majority of projects (137) is reliability followed by VER integration for seven projects and then four projects aimed at economics and congestion.

Areas have reported distribution transformer shortages and control shelter assemblies significantly impacting operations and continue to persist. Furthermore, shortages of 600 v cable have resulted in the need to find secondary suppliers during the summer seasons. Impacts span deferred construction work as crews wait for delated materials to be delivered.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[57] for the summer and winter of each year.[58] Projected total internal demand is based on normal weather (50/50 distribution)[59] 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[60]**	**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 sub-areas
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
WECC-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-NW	Summer	Noncoincident	
WECC-SW	Summer	Noncoincident	

57 Glossary of Terms Used in NERC Reliability Standards.
58 The summer season represents June–September and the winter season represents December–February.
59 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.
60 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.

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[61]

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.[62]

[61] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.
[62] 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):[63]
  - 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 at least one of the following guidelines (with consideration for an area's planning processes):[64]
  - 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.

[63] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[64] 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 (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level (RML): 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, system planners use this metric is 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 this 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.

Methods and Assumptions

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 electric 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 electric 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 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[65]
- 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 BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[66] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[67] 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,[68] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[69]
  - 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.

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65 Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
66 BES Definition
67 NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability
68 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.”
69 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.”

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

Planning Reserve Margins 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. Planning Reserve Margins 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 Planning Reserve Margins relative to its RML—a "target" or requirement based on traditional capacity planning criteria. 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 (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on 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 ARM is greater than RML.

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

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

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 is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. 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., 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.[70] 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.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

Normal Risk: Negligible amounts of LOLH and EUE.

Periods of Risk: LOLH < 2 Hours and EUE < 0.002% of total annual net energy.

Significant Risk: LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

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 electric 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 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.

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 power-flow model and cannot be categorized as “Under Construction” or “Planned”

Other projected lines that do not meet requirements of “Under Construction” or “Planned”

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

ERO Actions Summary

The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

Ongoing ERO Actions Addressing the *2023 LTRA* Recommendations		
1: Add new resources with needed reliability attributes and make existing resources more dependable.		
Initiative	**Description**	**Product/Reliability Solution**
Cold Weather Reliability Standards and Activities	New cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their RCs, Transmission Operators, and BAs for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation. NERC and the industry are currently developing the remaining Reliability Standard enhancements to address the staff report. Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* on NERC's standards development page.[71]	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The status of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[72] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the Reliability and Security Technical Committee. Refer to the RSTC-Approved Documents page.[73]	Reliability Guideline

[71] Project 2021-07
[72] IBR Activities
[73] RSTC Approved Documents

Ongoing ERO Actions Addressing the *2023 LTRA* Recommendations

2: Expand the transmission network to deliver supplies from new resources and locations to serve changing loads.

Initiative	Description	Product/Reliability Solution
Interregional Transfer Capability Study	NERC's study will analyze the amount of power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems. The study will be conducted in consultation with the six Regional Entities and each transmitting utility in neighboring transmission planning areas. Transfer capability is a critical measure of the ability to address energy deficiencies by relying on distant resources and is a key component of a reliable and resilient BPS. The study, which was directed in the Fiscal Responsibility Act of 2023, must be filed with FERC by December 2, 2024. A public comment period will take place when FERC publishes the study in the Federal Register. After submittal, FERC must provide a report to Congress within 12 months of closure of the public comment period with recommendations (if any) for statutory changes. Refer to the ITCS Initiatives page.[74]	ERO Study and Recommendations

3: Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

Initiative	Description	Product/Reliability Solution
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2023 LTRA* to advise industry and stakeholder of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically-sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[75] New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[76] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather*, requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[77]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The status of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[78]	Reliability Standards Reliability Guidelines Educational Webinars

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[74] ITCS Project
[75] ERAWG
[76] Project 2022-03
[77] Project 2023-07
[78] DER Activities

Ongoing ERO Actions Addressing the *2023 LTRA* Recommendations		
4: Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and regional entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships