BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

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

Exhibit 3-01:
2026 Bonneville "White Book"

BONNEVILLE POWER ADMINISTRATION

2026 Pacific Northwest Loads and Resources Study

April 2026





2026 PACIFIC NORTHWEST LOADS AND RESOURCES STUDY

The White Book

BONNEVILLE POWER ADMINISTRATION
April 2026

Cover Picture:
Source: BPA Photo Archive https://river.bpa.gov

Ice Harbor Dam is one of the four federal projects located on the Lower Snake River in the Pacific Northwest, resideing roughly in the southwestern region of Washington state and neighboring the Walla Walla and Franklin counties. It is part of the Columbia River Basin hydro projects, and it serves a variety of purposes such as irrigation, navigation, recreation and hydropower.

Ice Harbor Dam is a run-of-river type of dam, which began its service in 1961 and is operated by the U.S. Army Corps of Engineers.

For more information on The Ice Harbor Dam, please visit: Walla Walla District - Ice Harbor Lock and Dam

ACKNOWLEDGMENTS

Preparation of the annual Pacific Northwest loads and resources study is a complex, multidisciplinary effort. BPA wishes to acknowledge the team—BPA staff and others—whose diligence and dedication result in a reliable, high quality document.

Bonneville Power Administration

Generation Asset Management:

Long Term Power Planning Group
Regional Coordination Group
Operational Planning Group

Customer Support Services:

Load Forecasting and Analysis Group

Bulk Marketing and Transmission Services:

Long Term Sales and Purchasing Group

NW Requirements Marketing

Office of General Counsel

Pacific Northwest Utilities Conference Committee

Northwest Power & Conservation Council

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Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

April 10, 2026

In reply refer to: PGPR-5

Dear Interested Parties:

The Pacific Northwest Loads and Resources Study, commonly called "The White Book", is the Bonneville Power Administration's (BPA) annual publication of the Federal system and the Pacific Northwest's loads and resources for the upcoming 10-year period.

The White Book is used by BPA as a planning tool, as an information source for customers, as a published source of loads and resources information for regional interests, and as a data source for the Columbia River Treaty studies. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS) or to determine BPA revenues or rates.

Due to uncertainties related to the ongoing litigation concerning the Columbia River System Operations (CRSO), the 2026 White Book reflects long-term hydro operations based on the 2020 CRSO Environmental Impact Statement (EIS) Record of Decision (ROD) for the full 10-year study period.

This 2026 White Book presents the Federal system and the region's load obligations, contracts, and resources as of February 2026 for operating years (OY) 2027 through 2036. The 2026 White Book includes the following studies:

- **Federal system analysis—**forecast of Federal system firm loads and resources based on expected load obligations and different levels of generating resources that vary by water conditions. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm conditions, the Federal system is projected to have annual energy deficits across the study period, ranging from deficits of 408 to 931 average megawatt (aMW). Overall, these annual energy deficit projections are generally less than those projected in the 2025 White Book. Under median water conditions, the Federal system is projected to have annual energy surpluses throughout the study period.
- **PNW regional analysis—**forecast of regional firm loads and resources, based on expected retail loads and different levels of generating resources that vary by water conditions. The scheduled decommissioning of existing resources, the extent of forecasted load growth, the availability of uncommitted PNW Independent Power Producer (IPP) generation to meet regional load, and new resource additions are key variables in the results of this analysis. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm water conditions, the PNW is projected to have an annual energy surplus as large as 337 aMW in OY 2027, that sharply decrease to a deficit of 3,514 aMW by OY 2036. This result was mainly driven by the increasing PNW retail loads. Overall, the annual energy surplus/deficit position

projections are a slight improvement to forecasts from the 2025 White Book until the last year of the study period. Under median water conditions, the PNW region would begin to see energy deficits starting in OY 2034.

The 2026 White Book is available on BPA's website (https://www.bpa.gov/energy-andservices/power/resource-planning) or in hard copy format at BPA's Visitor Center, which you can reach toll-free at 800-622-4520 (or 503-230-4636). Detail reports regarding regional loads, contracts, and generating resources can be found in the Appendix and are available upon request via email to whitebook@bpa.gov.

Please send questions and/or comments to whitebook@bpa.gov.

Sincerely,

RACHEL DIBBLE Digitally signed by RACHEL DIBBLE
Date: 2026.04.10 08:03:10 -07'00'

Rachel Dibble
Vice President| Generation Asset Management
Bonneville Power Administration
Enclosure

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SECTION 1: SUMMARY

Planning Context

The Pacific Northwest Loads and Resources Study, commonly referred to as "The White Book," is a planning document produced by the Bonneville Power Administration (Bonneville) that presents its projection of load and resource conditions for the upcoming 10-year period from operating year (OY[1]) 2027 to 2036 (referred to in this document as "the study period"). The White Book includes analysis of Bonneville's forecasts of expected power obligations and resource generation for both the federal system and the Pacific Northwest[2] (PNW) region. Information contained in the White Book is used for: 1) long-term planning studies for Bonneville; 2) planning studies for the Columbia River Treaty; and 3) as a published record of information and data for customers and other regional planning entities. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS).

Bonneville's White Book traditionally focuses on long-term deterministic power planning for the federal system and the PNW region. The load and resource balance are calculated by comparing expected loads and contract obligations to forecast resource generation and contract purchases under the federal system. In the same manner, Bonneville's PNW regional analysis calculates the PNW regional load and resource balance by comparing expected regional retail loads and contract obligations to forecast regional resource generation and contract purchases. Hydropower resources for the federal system and PNW region include variability by incorporating a variety of generation forecasts, associated with streamflow from the most recent 30-historical water conditions of the 2020 modified flows. These deterministic analyses are modeled by OY to be consistent with regional coordination of the Treaty. Analytical results are presented in annual and monthly energy, expressed in average megawatts. The federal system analysis is presented in Section 2 and the Pacific Northwest regional analysis in Section 3.

Bonneville, like the rest of the electric power industry, continues to explore ways to comprehensively assess the ability of the power system to meet long-term load obligations. Periodically, Bonneville incorporates additional analysis and data into its planning that look at different analytical methods and evaluate different scenarios. This year's White Book does not incorporate any additional analysis.

The total retail load, contracts, and generation forecasts used in this study were updated as of February 2026. While Provider of Choice contracts were signed in December 2025, Bonneville will not have a full understanding of its Provider of Choice load obligations until Tier 2 elections are made in summer 2026. Thus, Provider of Choice updates are not included in this issue of White Book. The 2026 White Book supersedes the 2025 White Book and is published as a single summary document. A list of technical reports is located at the end of this summary document in the Appendix; individual reports are available upon request only. Requests for these reports can be made by emailing WhiteBook@bpa.gov.

[1] Operating Year (OY) is the time frame August 1 through July 31. For example, OY 2026 is August 1, 2025, through July 31, 2026.

[2] As defined in the Northwest Power Act

Load Obligations

The load obligations for the federal system and PNW region contain multiple components in this study. Forecasts are categorized as: 1) total retail loads(TRL), defined as each individual utility's total retail electric power consumption on its system, including electrical system losses; and 2) contract obligations, which include reported PNW utility long-term contract sales within the PNW region as intra-regional transfers (Out) and outside the PNW region as exports. Contract obligations also include federal system power sales delivered to federal agencies, public bodies, cooperatives, and tribal utilities as preference customers described under section 5 of the Northwest Electric Power Planning and Conservation Act (NW Power Act), 16 U.S.C. 839 et seq., (December 5, 1980).

Forecasts of the regional TRL and federal system load obligations are produced by Bonneville's Agency Load Forecasting (ALF) system. ALF forecasts are completed for individual PNW entities under one of two approaches: the largest share of load forecasts is now based on statistically adjusted end-use models, while other forecasts are based on time-series-based regressions that follow the fundamental assumptions of historical retail electricity consumption patterns continuing. The statistically adjusted end-use models include calculated indexes for heating and cooling equipment, and other components. ALF forecasts also assume normal weather conditions, using normalized temperatures based on recent history to incorporate evolving climate trends. Obligations associated with Bonneville's preference power sales contracts are forecast to continue as they are currently elected through the study period. Contract obligations not associated with Bonneville's preference power sales contracts follow individual contract terms throughout the life of the contract and are not assumed to be renewed. All federal system load and contract obligations are assumed to be firm and served by Bonneville regardless of weather, water or economic conditions.

Resource Types

Regional resources consist of physical generating facilities (currently on-line and/or under construction) and contract purchases that are used to serve retail loads. PNW resources, with federal systems included, are predominantly hydro based; therefore, generation levels can vary greatly both from month-to-month and from year-to-year. This analysis classifies resources as: 1) hydro resources, which include regulated, independent, and small hydro projects; 2) non-hydro renewable resources, which include wind, solar, and other renewable projects; 3) thermal resources, which include nuclear, coal, natural gas, petroleum, biofuel, and cogeneration projects; 4) contract purchases, which include reported PNW utility long-term contract purchases from within the PNW region as intra-regional transfer (In) and from outside the PNW region as imports. Generation forecasts for these resources are provided by Bonneville models or from the project owners, and those are described in detail in the following sections.

Hydro Resources

- Regulated hydro – Regulated hydro projects mainly consist of PNW Columbia River Basin hydro power projects for which the operation and generating capability is hydraulically linked. Bonneville forecasts the coordinated energy and capacity production from these hydro power projects using its hydro-system simulator model, called HYDSIM. The HYDSIM model considers individual project operating characteristics and conditions to determine energy production

expected on a project-to-project basis. Generation forecasts for these projects incorporate the month-to-month power and non-power requirements under each of the 30-year historical streamflow conditions of record, 1989 through 2018. The HYDSIM model is described further in the Hydro Resource Modeling section.

- Independent hydro - Independent hydro projects include those hydro projects whose generation output typically varies by water condition and are not operated or hydraulically linked to part of the Columbia River Basin. Independent hydro generation forecasts can vary month-to-month for energy and capacity and are developed and provided by individual project owners/operators for the same 30-year historical water conditions as the regulated hydro projects (1989 through 2018).
- Small hydro – Small hydro project generation forecasts are either provided by individual project owners or are based on historical actual generation. These generation forecasts vary month-to-month; however, they are not assumed to be dependent on water conditions.

Non-Hydro Resources

- Wind – Firm wind generation incorporates the statistical modeling of wind generation, based on historical weather data and actual generation, from currently operating PNW wind projects. The single operating year with the lowest total PNW wind generation is selected as firm wind year. The firm wind year generation performance determines each project's energy forecast. The federal system and PNW regional capacity analysis assume zero capacity contribution from wind resources.
- Solar – Solar projects are utility-scale solar facilities that are metered and send generation to the grid. This does not include any behind the meter resources. Generation forecasts are either provided by individual project owners or are based on historical actual generation. The federal system and PNW regional capacity analyses assume zero capacity contribution from solar resources.
- Other renewable resources – Other renewable resources include all other projects identified as renewable, including geothermal and biomass/biogas waste projects. Generation forecasts for these resources are based on energy and capacity forecasts submitted by individual project owners.

Thermal Resources

- Thermal resources include nuclear, coal, natural gas, petroleum, biofuel (not identified as renewable) and cogeneration projects. Generation forecasts for these projects are based on energy and capacity capabilities submitted by project owners. These forecasts typically vary month-to-month, and total plant generation is reduced to account for scheduled maintenance. Forecasts are adjusted to show actual operational capabilities and expectations and do not reflect economic dispatch.

Contract Purchases/ Imports

- Contract purchases include signed federal system purchases and regional contract purchases with power delivered to PNW entities that are reported by utilities publicly and in data submittals. These purchases are treated as resources in both the federal system and PNW

regional analyses. Purchases between entities within the PNW are called intra-regional transfer (In) and purchases from entities outside the PNW are categorized as imports. Except for contracts associated with the Treaty, all existing federal system and regional contract purchases follow individual contract terms throughout the life of the contract and are not assumed to be renewed. Treaty power deliveries are assumed to be in place throughout the study period.

Adjustment to Resources

The White Book assumes that resource generation and contract purchases are reliably delivered to load centers. To take this assumption into account, this study adjusts generation forecasts for: 1) operating and balancing reserves, which are held to meet reliability standards; and 2) transmission losses, associated with power deliveries. These adjustments are considered as reductions to both energy and capacity and are described below:

- Operating and balancing reserves: Operating reserves consist of both spinning and non-spinning contingency reserves that respond to the unforeseen loss of a resource, which are calculated by summing 3% of forecast load and 3% of forecast generation. Balancing reserves consist of regulation, load following, and imbalance reserves that are dedicated to maintaining within-hour load and resource balance. Details in modeling of reserves are described in the Hydro Resource Modeling section. Reserve forecasts included in this White Book are modeled consistently with those used in Bonneville's BP-26 rate case.
- Transmission losses: During the transmission of power to load centers, some of the electrical energy is lost, typically in the form of heat, which is categorized as transmission losses. Transmission loss factors are calculated monthly and vary by seasonal generation, e.g. summer months versus winter months. Transmission loss factors are applied to the sum of all generation and contract purchase forecasts. The monthly transmission loss factor has several components that combine to give the estimate of losses associated with federal system generation: 1) step-up transformers from generation to the high-voltage transmission network; 2) high-voltage network transmission; 3) transfers to federal loads over non-federal transmission systems; and 4) step-down transformers from high-voltage transmission to low-voltage delivery. The federal system transmission loss factors used in this White Book are consistent with those used in Bonneville's BP-26 rate case:
    - Energy: 2.83% from September through May, and 3.04% from June through August.
    - Capacity: 2.88% from September through May, and 3.09% from June through August.
- Wheeling loss (financial settlements): Wheeling losses are transmission losses incurred by transmission customers who have elected to settle those losses financially. The calculation of wheeling losses is based on the losses on the high-voltage network transmission system.

Hydro Resource Modeling

The HYDSIM hydro regulation model forecasts energy production from the regulated hydroelectric power projects in the PNW. This includes the 14 federal hydroelectric projects that make up the Columbia River Federal system, and other major hydro projects in the PNW. Project-level generation forecasts are produced in a continuous study for each month of the 30-year historical streamflow

record[3] which is October 1989 through September 2018. Energy production is maximized by coordinating hydro operations while meeting power and non-power requirements. HYDSIM produces results for 14 periods: ten complete months plus two periods each for April and August. April and August are divided, (first half/second half) due to natural streamflow and significant operational changes happening during these two months. Consequently, generation can differ significantly between the beginning and end of these months. For simplicity, the 14-period results are referred to as "monthly" values in this report.

The HYDSIM studies include the operational measures contained in the Columbia River System Operations (CRSO) Environmental Impact Statement (EIS) Record of Decision (ROD) released in September 2020, and the studies encompass both power and non-power operating requirements. Each hydro study specifies non-power hydroelectric project operations for fish, such as seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations and drawdown limitations, and turbine operation requirements.

Although the Pacific Northwest Coordination Agreement expired on September 15, 2024, PNCA project owners still provide Bonneville with physical plant data as well as power and non-power constraints. Bonneville incorporates this data into HYDSIM to simulate the coordinated operation of the PNW hydro system. As with previous White Books, these assumptions were included through the 10-year study horizon.

The construction of the three storage projects in Canada, (Mica, Arrow, and Duncan) under the Treaty between the United States and Canada, enhanced the volume of storage in the Columbia River Basin. These projects provide downstream power benefits by increasing the firm power generating capability of U.S. hydro projects. The Treaty calls for an Assured Operating Plan (AOP) to be completed six years prior to each operating year and allows a Detailed Operating Plan (DOP) to be completed, if agreed upon, in the year before the operating year. The Canadian project operations simulated in HYDSIM are based on the best available information from the Treaty planning and coordination process. Canadian operations included in this White Book are based on the official 2025 AOP studies, with additional modifications that reflect updates used in the official 2025 DOP studies.

Bonneville, along with the US Army Corps of Engineers, is continuing to implement operational and other obligations pursuant to the current Treaty and associated interim agreements. The Canadian Entitlement energy amounts included in this White Book for OY 2027 through OY 2036 are based on the amounts identified in the agreement-in-principle from July 2024, and interim agreements.

Balancing reserve requirements are additional items incorporated in the monthly hydro modeling. Bonneville holds capacity for balancing reserves following the North America Electric Reliability Corporation (NERC) standards and the Open Access Transmission Tariff (OATT) requirements within its balancing authority area (BAA). In this case, Bonneville holds it within the FCRPS. Holding the capacity of balancing reserve requirements reduce the ability to shape the federal system generation. For example, incremental reserves are modeled by reducing the generation capability of projects. Decremental reserves are not specifically reported in this study as they do not cause a limitation in generation capability.

[3] 2020 Modified Flows

Firm Planning

Bonneville bases its resource planning on firm expected generation to ensure sufficient generation to meet load obligations. Firm conditions are defined as when the PNW hydro system would be the most limited, due to a combination of operational constraints and low water conditions. For the federal system, this is established by considering the historical streamflow record, power and non-power operation constraints, and the planned operation of non-hydro resources, combined with the system load requirements. For operational purposes, Bonneville considers firm condition to be the tenth percentile (P10) of the monthly Tier 1 system firm critical output (T1SFCO) system results.

Variability of Hydro Generation

The generating capacity of the federal system and PNW regional hydro projects depends on several factors: 1) the amount of water flowing through the facilities; 2) the physical capacity of the facilities; 3) any flow or operating requirements, including those pursuant to biological opinions, court orders or applicable agreements; and 4) other operational limitations. Water conditions cause hydro generation to vary greatly year-to-year depending on weather factors such as precipitation, snowpack, and temperature. Project-level generation forecasts for regulated hydro resources are produced using HYDSIM for each of the 30-year historical streamflow conditions of record, which are based on the period from 1989 through 2018. Additionally, federal independent hydro project generation was updated by the Army Corps of Engineers, the Bureau of Reclamation, and other project owners, incorporating the 2020 modified flows and up to date project operations.

This White Book study uses three generation scenarios to demonstrate the magnitude of hydro generation variability:

- Firm water: tenth percentile (P10) of system generation by month, it represents the firm water condition for energy and capacity of the hydro system.
- Median water: 50th percentile (P50) of system generation by month, it represents the exact middle value of generation distribution for energy and capacity of the hydro system.
- High water: 90th percentile (P90) of system generation by month, this represents the high generation scenario of the energy and capacity of the hydro system.

Hydro Capacity Modeling

Bonneville uses the RiverWare[4] model to forecast usable hydro capacity for long-term planning. RiverWare incorporates the monthly historical 30 water-year reservoir storage and flows from HYDSIM to simulate the relationship of hydro energy to hydro peaking capability for system regulated hydro resources. For each month, RiverWare forecasts hourly federal system hydro generation by maximizing generation while meeting non-power requirements. The forecasts consider scheduled hydro maintenance and reserves.

[4] RiverWare is a river system modeling tool developed by the University of Colorado Boulder College of Engineering and Applied Science, more specifically by the Center for Advanced Decision Support for Water and Environmental Systems (CADSWES). RiverWare | Center for Advanced Decision Support for Water and Environmental Systems | University of Colorado Boulder

Notable Updates

The 2026 White Book includes updated forecasts of federal system power sales contracts (PSC) obligations, PNW regional total retail loads(TRL), and contract purchases as of February 2026.

Resource updates in this issue include:

- Hydro capabilities reflect the 2020 CRSO EIS ROD Preferred Alternative operations.
- Columbia Generating Station Extended Power Uprate work is scheduled during its standard refueling maintenance cycle for FY 2027, FY 2029, and FY 2031:
    - Extended downtime is expected to be between 80 to 90 days during the next three standard maintenance years, and the impact on generation will begin in mid-March and end before July. Historical refueling maintenance time has been around 40 days and typically starts in mid-May and finishes by late-June.
    - Energy generation increase post-EPU work is expected to be around 160 aMW, starting in FY 2032.

Sources of Uncertainty

Forecasts presented in this document represent the best information currently available under the defined metrics for loads and resources. However, all forecasts are affected by uncertainty in economic conditions, weather, environmental and governmental policies, and a variety of other factors that could significantly affect the magnitude, duration, and timing of projected surpluses and/or deficits. Uncertainties include:

- Changes to hydro system operations in response to Endangered Species Act requirements or other environmental considerations,
- Changes to hydro system operations in response to court actions and/or operational agreements,
- Natural variations in weather affecting electrical power demand and streamflow runoff that result in hydroelectric power generation changes,
- Potential new large individual retail load and/or other changes to major industrial operations,
- Potential service to new load such as new customers or the Department of Energy's Richland vitrification plant operations,
- Potential future policy requirements at local, state, and federal levels regarding the amount and type of renewable resources, conservation standards, electric vehicle saturation, and/or carbon emissions,
- Fuel cost and availability, which may be affected by environmental factors or competing uses for industry, transportation, and import/export markets,
- Changes to operating limits on existing and future thermal resources,
- Changes to retirement dates associated with resources,
- Failures of resources to operate at anticipated times and/or output levels,
- Changes to Treaty operations after the time the study was run,
- PNW entities' ability to purchase power from new and existing uncommitted regional resources to serve retail load,

- PNW entities' ability to purchase and transmit power from extra-regional import/export markets,
- Future obligations related to Provider of Choice elections.

The potential impacts of these and other sources of uncertainty are not quantified in this study.

SECTION 2: FEDERAL SYSTEM ANALYSIS

The federal system analysis provides a deterministic forecast of the federal system loads and resources over a 10-year period from OY 2027 through 2036. This analysis incorporates forecasts of the federal system's firm requirement power sales contract obligations, contract sales and purchases, and resource generation. This section presents firm federal system load and resource forecasts for energy. Additional detailed components of the federal system study are available upon request, and a list of available reports can be found in the Appendix.

Load Obligations

Bonneville's ALF system is used to forecast federal system load obligations, as described previously in Section 1: Summary – Load Obligations. Types of federal system load obligations include: 1) federal reserve power obligations to the U.S. Bureau of Reclamation (USBR); 2) Bonneville's Regional Dialogue (RD) PSC obligations to public, cooperative, and tribal utilities, and federal agency customers; 3) contract obligations to investor-owned utilities (IOUs); 4) contract obligations to direct service industry (DSI) customers; and finally 5) other Bonneville contract obligations including contract sales to entities within the PNW region (intra-regional transfers (OUT)) and to those outside the PNW region (exports). These load obligations are all considered firm power deliveries and are assumed to be served by the federal system regardless of weather conditions, water supply, or economic environments. Bonneville's forecasts of these obligations are categorized in the following sections.

USBR Obligations

USBR must meet statutory directives to provide reserve power to irrigation district facilities associated with USBR projects. Individual USBR project authorizations provide for irrigation districts to receive reserve power from specific FCRPS projects. The remaining power from USBR projects are marketed by Bonneville in the PNW.

Regional Dialogue Contract High-water Mark Power Service Agreement Obligations to Public and Federal Agency Customers

In December of 2008, Bonneville executed RD PSCs with public, cooperative, and tribal utilities, as well as federal agency customers. Bonneville is obligated to provide firm power deliveries from October 1, 2011, through September 30, 2028. Customers were offered three types of products: Load Following, Slice/Block, and Block. A total of 134 customers signed the RD contracts, and in this current period 124 are Load Following customers, seven are Slice/Block, and three are Block.

Under the RD PSCs, customers made periodic elections of how to serve their above rate period high-water mark (A-RHWM)[5] load by: 1) adding new non-federal resources; 2) acquiring power from non-

[5] "Through the contracts and rate methodology, each public utility will get a high-water mark (HWM) that defines its right to buy an amount of power at BPA's lowest cost-based Tier 1 rate. Power above the HWM must be purchased from either

federal resources; and/or 3) requesting Bonneville to supply additional power (as a Tier 2 load service). The final customer election was made in October 2024 and set through fiscal year (FY) 2028. This study assumes these, along with the current contract elections, continue throughout the study period. Based on this assumption, federal system RD PSC obligation forecasts include elected and forecast A-RHWM (Tier 2) load for the study period[6]. Table 2-1[7]presents the A-RHWM load included in Bonneville's obligations by fiscal year.

Table 2-1 Above Rate-High-Water-Mark Obligations (BP26 Rate Case)

FY	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy aMW	534	579	619	696	692	734	768	806	836	862

Investor-Owned Utility Load Service under Regional Dialogue Contracts

There are six IOUs in the PNW region: Avista Corporation, Idaho Power Company, Northwestern Energy Division of Northwestern Corporation, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. Although these IOUs have all signed Bonneville RD PSCs for FY 2011 through FY 2028, no IOUs have elected to take power service under these contracts thus no net requirement power sales are assumed for the IOUs through this study period.

Direct Service Industrial (DSI) Contracts

Bonneville currently has one customer, Port Townsend Paper Corporation. DSI deliveries are forecast at 11 aMW and expected to remain at that level throughout the study period.

Other Contract Obligations

Bonneville provides federal power under a variety of additional contract arrangements. These contracts obligations are categorized as: 1) power sales; 2) power or energy exchanges; 3) capacity sales or capacity-for-energy exchanges; 4) power payment for services; and 5) power commitments under the Treaty. These arrangements, collectively referred to as "Other Contract Obligations," are determined by individual contract provisions, and they have various delivery arrangements and rate structures. These contracts include power deliveries to entities within the PNW region as intra-regional transfers (Out), and to those outside of the PNW region as exports.

Treaty, RD PSCs, and DSI power deliveries are assumed to remain in place throughout the study horizon. Bonneville's Other Contract Obligations follow individual contract terms and are not assumed to be renewed after the expiration date.

Non-federal resources or from BPA at rates reflecting BPA's marginal cost of acquiring the additional power, or through a mix of BPA Tier 2 priced power and non-federal resources. (P.4 Regional Dialogue July 2007)

[6] Provider of Choice contracts were signed in December 2025. Bonneville will not have a full understanding of its Provider of Choice load obligations until Tier 2 elections are made in summer 2026. Due to this timing issue, Provider of Choice obligation are not included in this issue of White Book.

[7] A-RHWM load are the same as those reported in the 2025 White Book and as reference are from the BP26 Final Proposal.

Conservation

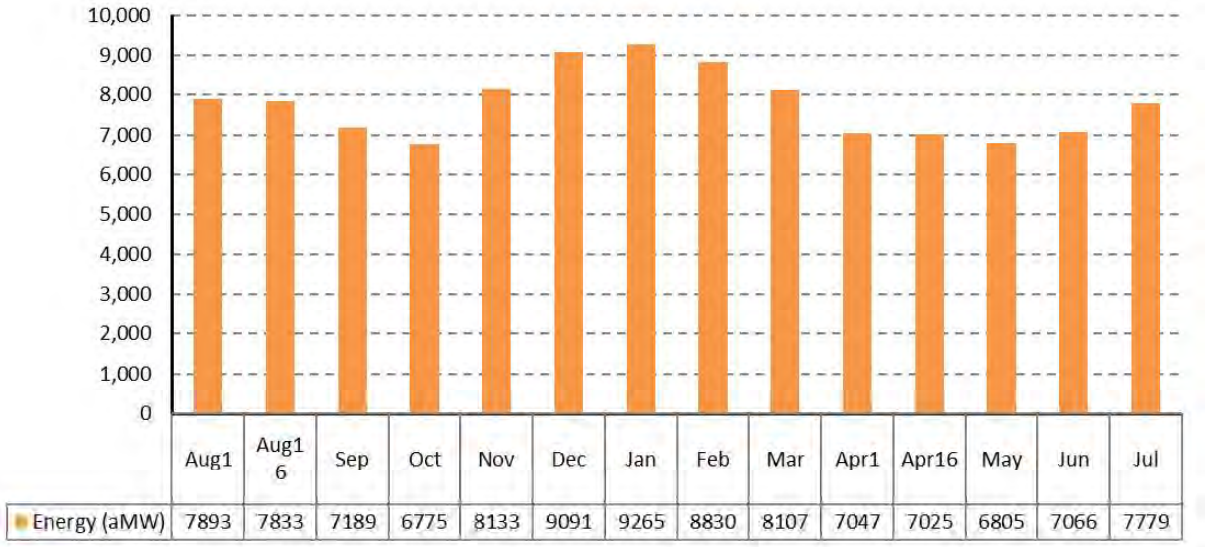
The PSC obligation forecasts developed by ALF are expected load forecasts, which include conservation identified by individual Bonneville customers. As an embedded assumption in the load forecasts, it is expected that the historically acquired amount of conservation will continue at the same rate going forward across the study period.

Firm Loads

The federal system total firm load forecast shows roughly 7% load growth over this 10-year study period. While Bonneville's forecast of PSC requirement loads increased almost 11% over the study period, Bonneville's exports and intra-regional transfers (OUT) decreased during this same period due to the expiration or decrease in delivery of contracts.

Overall, the total federal system load obligations remain relatively flat on an average annual basis over the study period, which is consistent with previous White Book studies due to the nature of Bonneville's RD PSCs. While produced on an annual basis, these obligations demonstrate little variation across the study period, because Bonneville's loads can vary greatly throughout the year. At a high level, Bonneville[8] experiences its highest loads in the late fall through winter months (November through March) primarily due to heating loads, with lower loads during spring, early summer, and early fall months when temperatures are milder. July and August loads tend to be slightly higher than the rest of the summer months due to increasing air conditioning demands. Table 2-2 illustrates the monthly shape of the forecast federal system firm load obligations for OY 2027.

Table 2-2 Federal System Firm Obligations for OY2027 - Monthly



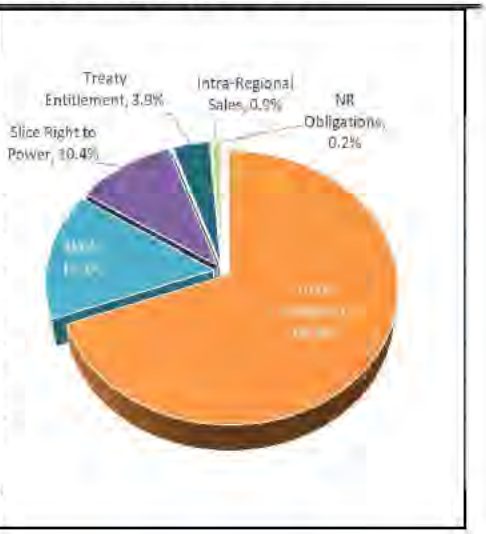
	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	7893	7833	7189	6775	8133	9091	9265	8830	8107	7047	7025	6805	7066	7779

Table 2-3 shows the annual make-up of the federal system firm load obligations for OY 2027 in average megawatts. Obligations for New Resources (NR) firm power rates are included for the first time starting in BP-26 rate case.

[8] This is reflective of Bonneville's total aggregate loads; individual customers highest loads vary by month and season.

Table 2-3 Federal System Annual Firm Obligations by Category OY 2027

Customer Class	RD PSCs	Energy (aMW)	Percent of Firm Energy
Load Following	Yes	5,419	69.2%
Block	Yes	1,187	15.2%
Slice Right to Power	Yes	812	10.4%
DSI	No	11	0.1%
Treaty Canadian Entitlement	No	305	3.9%
Exports	No	7	0.1%
Intra-Regional Sales	No	68	0.9%
New Resource (NR) Obligations	No	17	0.2%
Total Firm Obligations	--	**7,825**	**100%**



RD PSCs expire at the end of FY2028, and new 19-year Provider of Choice contracts were signed in December 2025. Post-2028 obligation details will be available in the summer of 2026. Due to the timing of this publication, this study assumes a continuation of RD PSC load levels for planning purposes.

Resources

In the PNW, Bonneville is directed to market power from federal hydroelectric projects and other resources acquired to meet firm power contractual obligations. By statute, Bonneville does not own generating resources, but instead, Bonneville markets power from federal resources and non-federal generating resources whose output Bonneville has acquired under contract. These resources and contract purchases are collectively referred to as "federal system resources" in this study. Federal system resources are currently comprised of: 1) hydro resources, which include regulated, independent, and small hydro projects; 2) non-hydro renewable resources (wind projects); 3) thermal resources (Columbia Generating Station); and 4) contract purchases, which are purchases from entities within the PNW region as intra-regional transfers(In), including the estimated Mid-C non-federal Canadian Entitlement return power (downstream benefit return as part of Columbia River Treaty) and from those outside of the PNW region as imports.

Federal System Resource Types

Table 2-5 summarizes Bonneville's resources and contract purchases available to meet the federal system load obligations. For OY 2027, federal system resources are forecast to produce 7,290 annual aMW of generation under firm water conditions, with reserves and losses included.

Table 2-5 Federal System Generations by Resource Type for OY 2027 - Firm Water Conditions

Resource Type	Annual Energy (aMW)	Percent of Firm Energy
Hydro	6,610	85%
Nuclear	853	11%
Wind	20	0.3%
Contract Purchases	255	3.3%
Total Federal Resources	7,738	100%
Reserves and Losses	-448	--
Total Net Resources	7,290	--



Federal System Contract Purchases

Bonneville purchases or receives power under a variety of contract arrangements from entities within the PNW region as intra-regional transfers(In), and from outside the region as imports, to meet federal system load obligations. These contract purchases, presented in Table 2-7 are made up of: 1) power purchases; 2) power or energy exchange purchases; 3) the estimated Mid-C non-federal Canadian Entitlement return power; and 4) transmission loss returns under Slice/Block contracts. Bonneville's contract purchases are considered firm resources that are delivered to the federal system regardless of weather, water, or economic conditions. Transmission loss returns capture the return of Slice/Block transmission losses to the federal system as specified in the Slice/Block contract, and these returns are treated as federal system resources. Except for the estimated Mid-C non-federal Canadian Entitlement return power and transmission loss return of Slice/Block contracts, each contract purchase follows specific delivery terms and expiration dates and is not assumed to be renewed.

The federal system resources are comprised of:

- Federal system hydro resources: Table 2-6 details the federal system hydro resources from which Bonneville markets firm and non-firm power. Additionally, it shows the variability of individual federal system hydro project generation for the three water conditions: firm, median, and high.
- Federal system non-hydro resources: federal system non-hydro resources are generating resources whose output has been purchased by Bonneville. Table 2-7 details these generating resources, which include: 1) Columbia Generating Station; and 2) wind projects (non-hydro renewable resources). Forecasts for these resources are generally consistent from year to year but may change annually based on scheduling of annual maintenance, refueling, and capital improvements.

Table 2-6 Federal System Hydro Project Generation Forecasts by Streamflow Conditions[9] – OY 2027

	Project	Initial Service Year	Operator	Number of Units	Maximum Capacity [d/] (MW)	High Water Energy [c/] (aMW)	Median Waer Energy [c/] (aMW)	Firm Water Energy [a/ c/] (aMW)
Regulated Hydro Projects								
1.	Albeni Falls	1955	USACE	3	50	23.6	24.9	24.2
2.	Bonneville	1938	USACE	18	1,221	1,758	1,431	1,122
3.	Chief Joseph	1955	USACE	27	2,614	721	525	378
4.	Dworshak	1974	USACE	3	465	288	163	181
5.	Grand Coulee	1941	USBR	27	6,684	3,083	2,401	1,883
	GCL Pumping	1973		6	314			
6.	Hungry Horse	1952	USBR	4	310	120	111	89.7
7.	Ice Harbor	1961	USACE	6	693	297	190	159
8.	John Day	1968	USACE	16	2,480	1,376	974	749
9.	Libby	1975	USACE	5	605	265	219	218
10.	Little Goose	1970	USACE	6	930	319	192	154
11.	Lower Granite	1975	USACE	6	930	337	197	144
12.	Lower Monumental	1969	USACE	6	930	337	197	151
13.	McNary	1953	USACE	14	1,120	773	569	453
14.	The Dalles	1957	USACE	22	2,080	1,074	802	622
15.	Total Regulated Hydro Projects			169	21,426	10,771	8,001	6,328
Independent Hydro Projects								
16.	Anderson Ranch	1950	USBR	2	40	17.9	13.6	8.7
17.	Big Cliff	1954	USACE	1	21	13.6	11.3	11.5
18.	Black Canyon	1925	USBR	2	8.5	7.2	6.0	6.0
19.	Boise Diversion	1908	USBR	3	2.5	1.4	1.3	1.0
20.	Chandler	1956	USBR	2	12.2	8.2	6.7	5.5
21.	Cougar	1964	USACE	2	28	9.0	6.1	5.2
22.	Cowlitz Falls	1994	LCPD#1	2	70	39.3	27.8	29.0
23.	Detroit	1953	USACE	2	115	31.7	22.0	24.9
24.	Dexter	1955	USACE	1	17	9.8	8.3	8.0
25.	Foster	1968	USACE	2	23	9.3	7.0	8.0
26.	Green Peter	1967	USACE	2	92	21.7	12.2	17.1
27.	Green Springs	1960	USBR	1	18	6.7	6.7	6.7
28.	Hills Creek	1962	USACE	2	34	23.3	19.4	16.4
29.	Lookout Point	1954	USACE	3	138	10.5	17.8	12.1
30.	Lost Creek	1975	USACE	2	56	38.2	35.7	26.5
31.	Minidoka	1909	USBR	4	28	15.7	12.5	11.2
32.	Palisades	1957	USBR	4	177	84.6	77.7	74.3
33.	Roza	1958	USBR	1	14	8.7	7.4	7.1
34.	Total Independent Hydro Projects			38	894	357	299	279
Small Non-Federally Owned Hydro Projects								
35.	Dworshak/ Clearwater Small Hydro	2000	ID DWR	1	5.4	2.6	2.6	2.6
36.	Rocky Brook	1985	MCPD#1	1	1.6	0.25	0.25	0.25
37.	Total Non-Federally Owned Hydro Projects			2	7	2.9	2.9	2.9
38.	Total Hydro Generation			209	22,327	11,131	8,304	6,610

a/ Firm Energy is the 12-month annual average for OY2027, assuming 10th percentile (P10) water conditions

b/ Bonneville Dam generation total includes Bonneville Fishway

c/ High Water Energy = 90th percentile (P90) water conditions, Median Water Energy = 50th percentile (P50) water conditions

d/ Maximum Capacity represents full capacity of resource including overload.

[9] Streamflow conditions do not always have a linear correlation with generation output. Projects with smaller head (head = forebay level minus tailwater level) are susceptible to having the inverse effect between flow and generation, e.g. Albeni Falls. Higher flow passes through the project increasing the tailwater level which results in less head, this results in lower generation than in other lower flow conditions.

Projects (dams) on Table 2-6 under some commonly known groups are:

- **The Lower Snake River projects (4)**: Lower Granite, Little Goose, Lower Monumental, and Ice Harbor.
- **The Lower Columbia River projects (4)**: McNary, John Day, The Dalles, and Bonneville.
- **The federal 10 regulated projects**: Grand Coulee, Chief Joseph, The Lower Snake River projects, and the Lower Columbia River projects.
- **The federal 14 projects**: Aleni Falls, Dworshak, Hungry Horse, Libby, and the Federal 10 Regulated projects.
- **The Willamette River projects (8)**: Big Cliff, Cougar, Detroit, Dexter, Foster, Green Peter, Hills Greek, and Lookout Point.

Table 2-7 Federal System Non-Hydro Project Generation Forecast and Contract Purchase – OY 2027

	Project	Initial Service Date	Resource Type	Operator	Maximum Capacity [a/] (Peak MW)	Firm Energy (aMW)
Non-Hydro Resources						
1	Columbia Generating Station	1984	Nuclear	ENW	1,178	853
2	Klondike Phase III [b/]	2007	Wind	NW Wind Power	0	11.8
3	Stateline Wind Project [c/]	2001	Wind	PPM, FLP	0	8.0
4	Fourmile Hill Geothermal [d/]	Not in Service	Geothermal	Calpine	0	0
5	Total Federal System Non-Hydro Resources				1,178	873
Contract Purchases						
6	Canadian Entitlement for Canada (non-Federal)				147	84
7	Canadian Imports				1	1
8	Pacific Northwest Imports				0	0
9	Intra-Regional Transfer In (Pacific Northwest Purchases)				175	155
10	Slice Transmission Loss Return				34	15
11	Total Federal System Contract Purchases				357	255
12	Total Federal System Non-Hydro Resources and Contract Purchases				1,535	1,128

a/ This is the maximum generation for January 2027

b/ Klondike III Project expiring in 2029

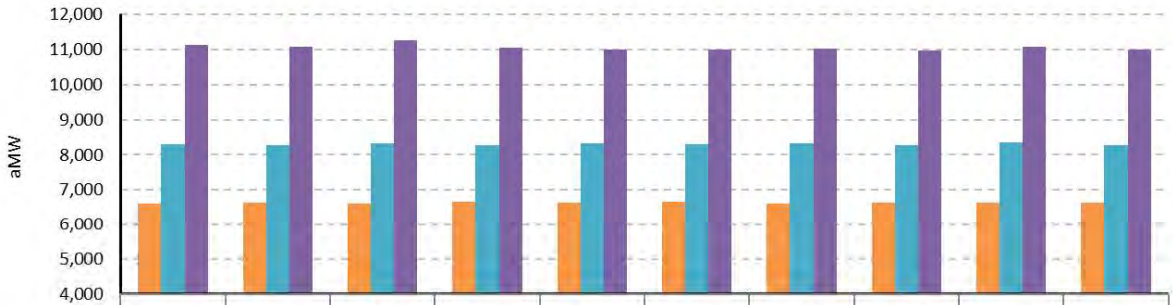
c/ Stateline Wind Project contract expiring in 2028

d/ Fourmile Hill is not assumed to be in operation within the study period

Federal System Hydro Generation Variability

The generating capacity of federal system hydroelectric projects depends on the amount of water flowing through the facilities, the physical capacity of the facilities, flow requirements pursuant to biological opinions, a combination of other power and non-power constraints, and other operating limitations. Table 2-8 shows the annual variability of hydro generation under the three water conditions. Although hydro generation changes drastically from different water conditions, within each condition; however, it changes only slightly from year to year.

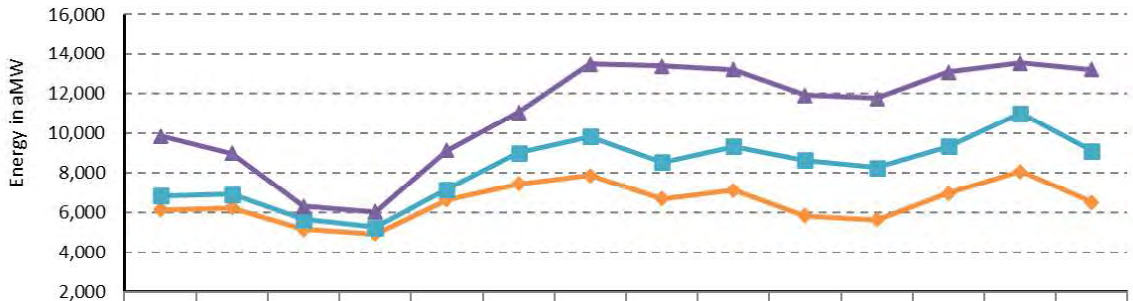
Table 2-8 Federal System Variability of Annual Hydro Generation by Streamflow Conditions – OY 2027 – OY 2036



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Firm Water (P10)	6,610	6,643	6,616	6,653	6,627	6,664	6,607	6,639	6,640	6,646
Median Water (P50)	8,304	8,272	8,318	8,283	8,334	8,294	8,320	8,264	8,359	8,271
High Water (P90)	11,131	11,081	11,252	11,038	11,003	10,992	11,025	10,966	11,085	10,988

In OY 2027, annual federal system hydro energy generation is forecast to be 6,610 aMW under firm water conditions. However, under the high water conditions these same federal system hydro resources could generate as much as 11,131 aMW. Table 2-9 displays the monthly variability of the federal system hydro generation forecast for OY 2027, under the same three water conditions. Higher generation levels from January through March are largely due to drafting reservoirs for flood risk management and power production. Available water in those months depends greatly on annual rainfall and snowpack levels in the Columbia River Basin, and thus the generation exhibits large variability from year to year. Power production from April through July is variable based on the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early fall as stream flows decline due to depleted snowpack and lower precipitation levels. Annual water volume variability generally has little impact on generation from the federal system hydro resources in September and October. As observed from Table 2-9, hydro generation can vary by nearly 6,700 aMW in a single month, essentially doubled in this case the month of February, depending on operations and availability of water.

Table 2-9 Federal System Monthly Hydro Generation Variability by Streamflow Conditions – OY2027

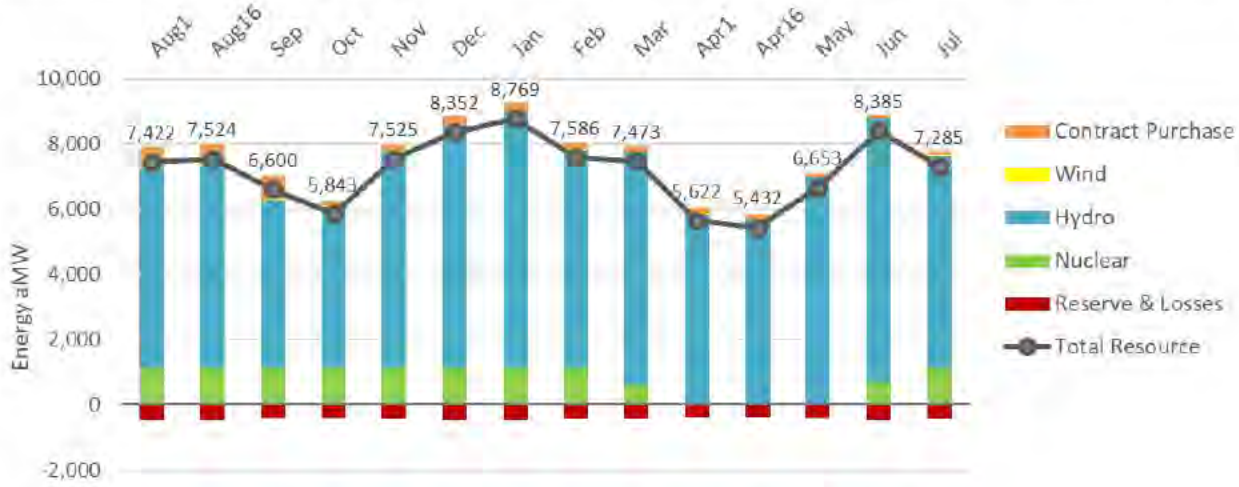


	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Firm Water (P10)	6,147	6,246	5,150	4,940	6,638	7,441	7,870	6,687	7,108	5,838	5,645	6,968	8,053	6,511
Median Water (P50)	6,846	6,905	5,660	5,258	7,160	9,026	9,848	8,539	9,332	8,642	8,264	9,348	11,022	9,116
High Water (P90)	9,867	8,985	6,318	6,043	9,144	11,079	13,483	13,387	13,189	11,918	11,770	13,063	13,516	13,194

Total Federal System Resources

Table 2-10 shows the monthly shape of forecast total federal system resources in energy (aMW) for OY 2027, under firm water conditions. This includes generation from all federal system hydro and non-hydro resources, as well as contract purchases. Overall, the federal system has the highest net generation forecast in winter months to early spring and mid-summer periods. Noting the drop of generation from nuclear starting in the month of March through June, this is the CGS EPU extended down time during the standard refueling maintenance scheduled for OY 2027.

Table 2-10 Federal System Monthly Generation for OY 2027 under Firm Water Conditions



Key Results

Annual Energy

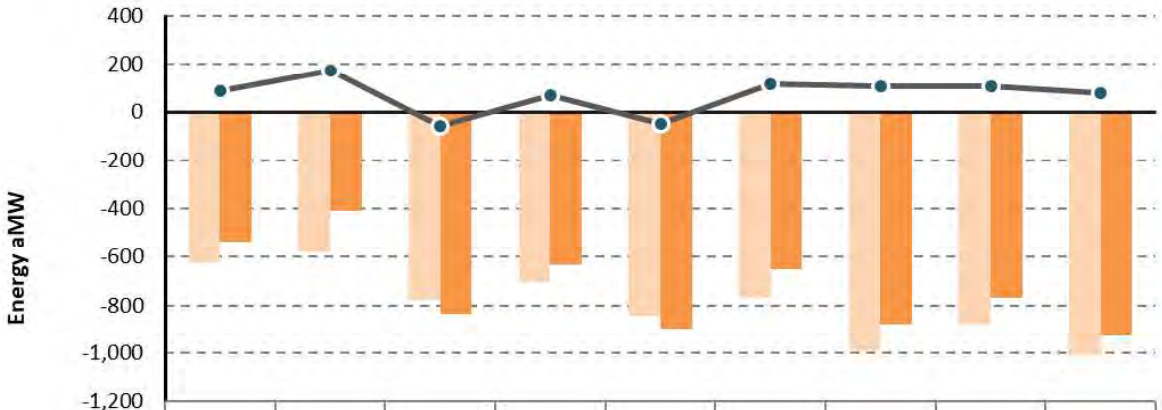
Table 2-11 shows that the federal system is forecast to have annual energy deficits throughout the study period. The individual components of the federal system annual energy loads and resources are shown in Exhibit 4-1 for OY 2027 through OY 2036. The federal system detailed monthly energy loads and resources are shown in Exhibit 4-2 for OY 2027.

Table 2-11 Federal System Annual Energy Surplus/Deficit under Firm Water Conditions

Energy (aMW)	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Surplus/Deficits	-535	-408	-834	-633	-897	-650	-879	-767	-931	-834

Table 2-12 compares the current (2026) White Book federal system annual firm energy surplus/deficit results to those from the 2025 White Book. In this comparison, the 2026 White Book shows a slight improvement in deficits annually in seven of the ten years. This improvement can be attributed to the decrease in federal obligations in the first half of the study period and the increase in federal resources from CGS EPU in the latter half.

Table 2-12 Federal System Annual Energy Surplus/Deficits Comparison under Firm Water

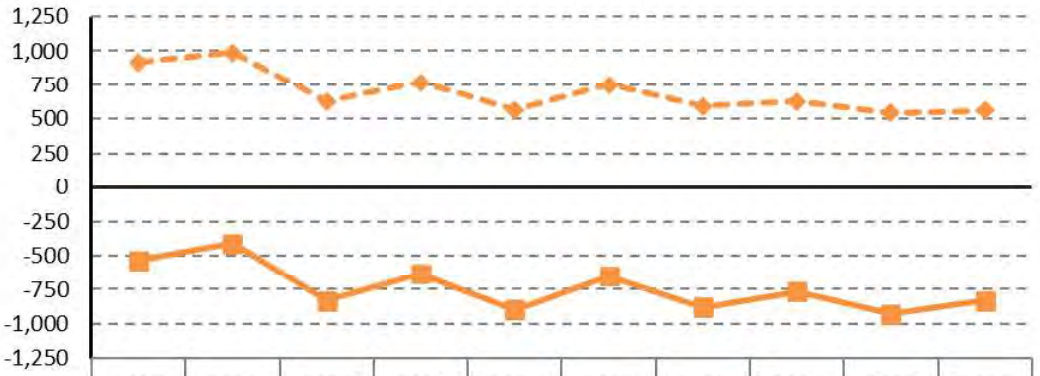


	2027	2028	2029	2030	2031	2032	2033	2034	2035
2025 White Book	-622	-580	-778	-701	-846	-768	-988	-876	-1012
2026 White Book	-535	-408	-834	-633	-897	-650	-879	-767	-931
Delta	87	171	-56	68	-51	118	110	109	80

Federal System Annual Surplus/Deficit

Table 2-13 graphically presents the annual firm and median conditions energy surplus/deficits. Over the study period, the federal system is forecast to have a deficit in annual firm energy as high as 931 aMW near the end of the study period. Noticeable differences in annual energy between odd and even years can be attributed to the biennial Columbia Generation Station (CGS) refueling maintenance schedule[10]. Under median water conditions, in contrast, the federal system is surplus throughout the study period.

Table 2-13 Federal System Annual Surplus/Deficits Under Firm & Median Water Conditions



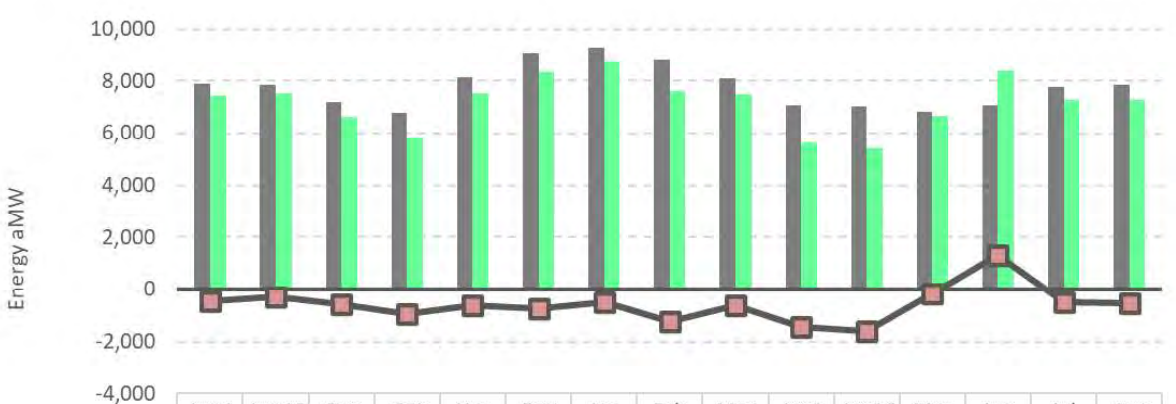
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Energy (aMW) p10	-535	-408	-834	-633	-897	-650	-879	-767	-931	-834
Energy (aMW) p50	919	990	628	767	568	750	592	627	544	562

[10] Columbia Generating Station has routine maintenance cycle scheduled in odd calendar years, specifically in months of May and June. Historically, CGS is forecast to produce 994 aMW annually during maintenance years, and 1,116 aMW annually during non-maintenance years before the EPU. Post EPU work, CGS is forecast to add 160 aMW to its annually energy, increasing its generation to roughly 1275 aMW in non-maintenance years.

Federal System Monthly Surplus/Deficit

Table 2-14 displays a graphic look at the federal system monthly firm energy surplus/deficits, along with total firm obligations and total net resources, for OY 2027. The largest deficit comes in the month of April due to CGS scheduled extended downtime combined with time just before run-off begins, and better positions in the months of May and June, after spring run-off.

Table 2-14 Federal System Monthly Surplus/Deficits OY 2027 under Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Total Firm Obligations	7893	7833	7189	6775	8133	9091	9265	8830	8107	7047	7025	6805	7066	7779	7825
Total Net Resources	7422	7524	6600	5843	7525	8352	8769	7586	7473	5622	5432	6653	8385	7285	7290
Surplus/ Defiict	-471	-309	-589	-932	-607	-738	-496	-1244	-635	-1425	-1593	-151	1319	-494	-535

Conclusion

Under firm water conditions, the federal system shows annual firm energy deficits through the 2027-2036 study period. These annual energy deficits range from 408 aMW in OY 2028, to as high as over 900 aMW in OY 2035. At a monthly resolution under firm water conditions, the federal system generally shows larger energy deficits across the winter and early spring periods until spring runoff starts, which then turns into surplus from May and to the early summer periods.

The federal system surplus/deficit forecasts understandably, in general, have a positive relationship with water conditions. Better water conditions generally yield more surplus overall. For example, the annual energy surplus can increase by over 3,500 aMW under better water conditions, from firm water to high water conditions, while monthly surplus or deficit position can vary by over 5,500 aMW within the same year under the same month.

The range of federal system monthly surplus and deficit forecasts under all 30 water years is presented in Exhibit 4-3. Additional monthly and annual details for OY 2027 through OY 2036 are available upon request. A list of available data reports can be found in the Appendix. Data requests can be sent to WhiteBook@bpa.gov.

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SECTION 3: PACIFIC NORTHWEST REGIONAL ANALYSIS

The PNW Regional Analysis is an OY analysis that provides Bonneville's deterministic forecast of the PNW region's loads and resources over a 10-year period from OY 2027 through OY 2036. Firm load and resources forecasts are presented in energy based on regional retail loads, contract obligations, and resources. This White Book analysis assumes that generation from all regional, uncommitted independent power producer (IPP) projects is available to meet regional load. Regional retail loads, contract sales and purchases, and generating resource forecasts incorporate annual regional utility data submittals received by Bonneville.

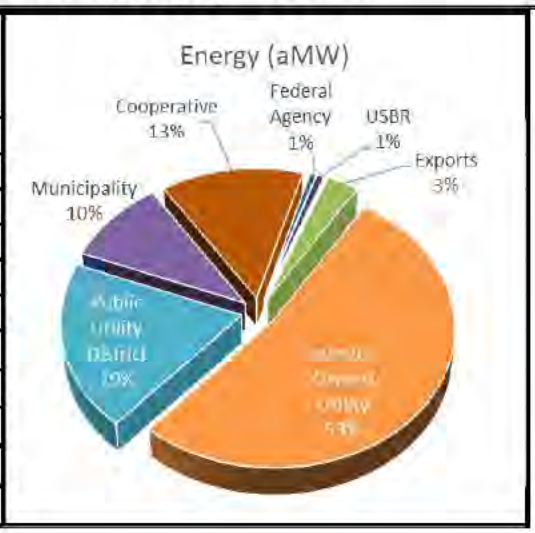
Regional Loads

Regional analysis incorporates regional load projections, which consist of two separate components: 1) total retail loads (TRL), which is the sum of individual utilities' retail power consumption within the PNW region; and 2) regional contract sales (exports), which are the sum of all reported long-term regional contract deliveries to entities outside the PNW region. The TRL forecasts for the regional analysis are developed by Bonneville's ALF system. TRL forecasts reflect normal weather conditions, including historical conservation savings, and do not include specific adjustments for evolving climate trends. Apart from power commitments under the Treaty, all export contract deliveries follow individual contract terms and are not assumed to be renewed after their expiration dates. Treaty power deliveries are assumed to be in place throughout the study period. The sum of the forecast total retail load and export contracts represents the regional loads for the PNW.

Regional loads are comprised of roughly 97% retail loads and 4% exports. Table 3-1 shows the forecast composition of PNW regional load for OY 2027.

Table 3-1 PNW Region Firm Loads by Customer Category – OY 2027

Customer Class	Energy (aMW)	Percent of Firm Energy
Investor-Owned Utility	13,902	53%
Public Utility District	5,150	19%
Municipality	2,601	10%
Cooperative	3,575	13%
Federal Agency	152	0.6%
USBR	194	0.7%
DSI	51	0.2%
Marketer	0	0.0%
Total Retail Load	**25,626**	**97%**
Exports	794	3%
Total Regional Load	**26,420**	**100%**



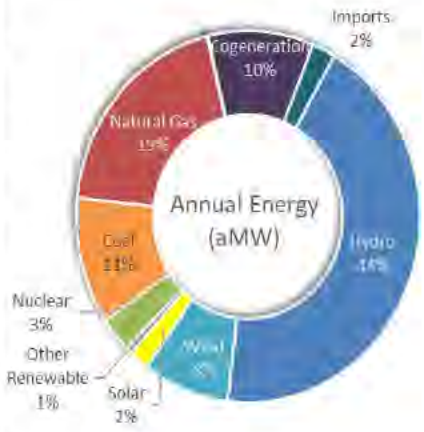
Regional Resources

PNW resources and contract purchases are collectively called "regional resources" in this study. Similarly to the federal system resources, regional resources vary monthly by water conditions, resource type, and seasonality of generating resource potential. This analysis classifies resources as: 1) hydro resources, which include regulated, independent, and small hydro projects; 2) non-hydro renewable resources which include wind, solar, and other projects; 3) thermal resources which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; and 4) contract purchases which are identified as imports.

Table 3-3 summarizes the resource generation available to meet PNW regional loads. The generation forecasts for these resources are provided by Bonneville models or the project owners. New regional generating projects are included when those resources begin operating, or are under construction, and have a scheduled on-line date. Similarly, retiring resources are removed from the forecasts based on the data of the announced retirement date. Contract purchases are provided by the individual utility, follow specific contract provisions, and can have various delivery arrangements.

Table 3-3 PNW Regional Generations by Resource Type – OY 2027 Firm Water Conditions

Project Type	Annual Energy (aMW)	Percent of Energy
Hydro	12,009	43.6%
Wind	2,240	8.1%
Solar	510	1.9%
Other Renewable	157	0.6%
Nuclear	853	3.1%
Coal	3,049	11.1%
Natural Gas	5,371	19.5%
Petroleum	0	0.0%
Biofuel	26	0.1%
Cogeneration	2,737	9.9%
Imports	600	2.2%
Total Regional Resources	27,552	100%



Regional Hydro Generation Variability

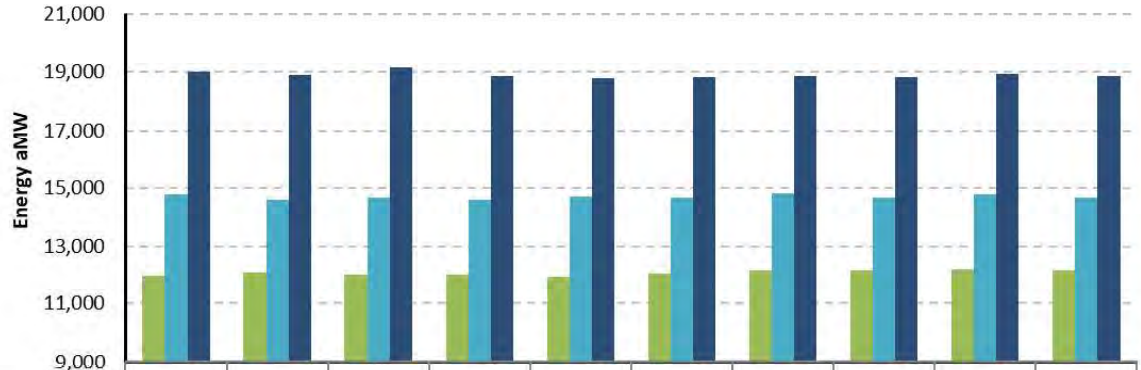
The generating capability of regional hydroelectric projects depends upon the amount of water flowing through the facilities, the physical capacity of the facility, flow requirements pursuant to non-power requirements, and other operating limitations. Similarly to federal hydro resources, Bonneville uses the 30-year streamflow record for planning purposes, and three water conditions are presented here to represent the magnitude of hydro generation variability.

Table 3-4 shows the annual variability of the region's hydro generation under the three streamflow scenarios. Details on the different streamflow scenarios please refer to Hydro Resource Modeling section.

In OY2027, annual firm energy generation from regional hydro projects is forecast to be 12,009 aMW under the firm water conditions, and this represents about 44% of the region's resources. The

generating potential from regional hydro projects can vary annually by nearly 7,000 aMW between firm and high water conditions within the same year.

Table 3-4 PNW Regional Annual Variability of Hydro Generation by Streamflow Conditions



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Firm Water (P10)	12,009	12,094	12,013	12,038	11,960	12,047	12,185	12,177	12,215	12,182
Median Water (P50)	14,769	14,597	14,654	14,612	14,698	14,658	14,805	14,681	14,797	14,688
High Water (P90)	19,000	18,900	19,133	18,850	18,800	18,806	18,864	18,815	18,923	18,838

Table 3-5 shows the monthly variability of regional hydro generation under the same three water conditions for OY 2027. The increased level of generation in January through March is largely due to drafting reservoirs for power production and flood risk management, which can vary widely due to rainfall and snowpack levels in the Columbia River Basin. Power production fluctuations in the second half of April through July are highly related to the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early fall as streamflows are reduced due to depleted snowpack and lower precipitation levels. Water variability does not have a substantial impact on regional hydro generation from September through October as those are the months with overall lowest water availabilities. Regional hydro generation capability can vary by as much as 10,000+ aMW between firm and high water conditions in the same month, in the example of OY 2027, months of February, second half of April, as well as July all exhibiting this level of range.

Table 3-5 PNW Regional Hydro Generation Monthly Variability by Streamflow Conditions – OY 2027



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Firm Water (P10)	10,905	10,573	9,103	9,784	12,377	13,414	14,076	11,385	12,710	11,049	11,024	13,842	14,056	11,488	12,009
Median Water (P50)	11,432	11,550	9,705	9,591	12,804	15,338	17,559	14,403	16,141	15,789	15,640	18,609	19,227	16,558	14,769
High Water (P90)	16,387	15,190	11,473	10,835	16,679	18,933	22,222	21,504	21,202	20,741	21,104	23,066	22,969	22,545	19,000

Uncommitted Independent Power Production Generation Delivered to the PNW

The PNW regional study includes uncommitted PNW IPP generation as regional resources. These resources, or the share of these resources that are not committed to serving specific loads, represent approximately 2,558 aMW of energy for OY 2027. The inclusion of this uncommitted IPP generation is reasonable from the long-term planning perspective because the PNW regional analysis does not include any reliance on market purchases. However, PNW utilities may have to compete with other western markets to secure this generation to meet electricity demands. Table 3-6, next, details the region's total uncommitted IPP annual energy generation forecasts over the OY 2027 through OY 2036 study period.

Table 3-6 PNW Regional Annual Uncommitted IPP Generation

Regional Uncommitted IPP	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Annual Energy (aMW)	2,558	2,588	2,591	2,596	2,591	2,594	2,587	2,597	2,597	2,595

Table 3-7 details the region's uncommitted IPP projects and the associated fuel types. If uncommitted IPP generation is secured for long-term periods by load serving entities within the region or outside the region, the IPP forecasts will be updated in future studies to reflect those changes.

Table 3-7 PNW Regional Uncommitted Independent Power Producer Projects – OY 2027 Firm Water Conditions

Project	Fuel Type	Energy (aMW)
Airport Solar	Solar	13
Centralia Complex [a/]	Coal	0
Clearwater Wind	Wind	23
Condon Wind	Wind	12
Cosmopolis Specialty Fibres	Wood Waste	14
Goose Prairie Solar	Solar	17
Hermiston Power Project	Natural Gas	567
International Paper Energy Center	Wood Waste	16
Juniper Canyon Wind	Wind	36
Kittitas Valley Wind	Wind	24
Klamath Generation Facility	Natural Gas	436
Klamath Generation Peakings (CT)	Natural Gas	90
Klondike Wind 1	Wind	6
Klondike Wind 3	Wind	23
Klondike Wind 3a	Wind	18
Leaning Juniper Wind	Wind	47
Longview Fibre Paper & Packaging	Wood Waste	35
Nippon Paper Cogen (Port Angeles)	Wood Waste	5
Pelton	Hydro	14
Priest Rapids	Hydro	85
Rock Island	Hydro	167
Rocky Reach	Hydro	155
Round Butte	Hydro	30
Satsop Combustion Turbine Project	Natural Gas	584

Project	Fuel Type	Energy (aMW)
SDS Lumber	Wood Waste	1
Smith Creek (Idaho)	Hydro	7
Stateline Wind	Wind	26
Stimson Lumber (Plummer)	Wood Waste	7
Tacoma Biomass (WestRock)	Wood Waste	0
Tieton Dam (Yakima)	Hydro	0
Vansycle Wind	Wind	23
Wanapum	Hydro	25
Weyerhaeuser Longview	Wood Waste	35
Willow Creek Wind	Wind	17
Total Uncommitted IPP Generation		**2,558**

a/ Centralia #2 (670 MW) was scheduled for retirement on Dec 1, 2025, extended by Executive Order Nos. 202-25-11 and 202-25-11B to operate for 90 additional days; it is planned to be converted to Natural Gas plant by 2038.

Key Results

Annual Energy

Table 3-8 shows annual energy surpluses for the PNW region in the first two operating years, then increasingly more deficit going forward to outyears. This study assumes that 100% of the PNW region's uncommitted IPP generation (2,558 aMW in OY 2027) is available to serve regional loads. The individual components of the PNW regional annual energy loads and resources for OY 2027 through OY 2036 are shown in Exhibit 5-1, and OY 2027 monthly PNW regional details are shown in Exhibit 5-2. Other details of each component for OY 2027 through OY 2036 are available upon request via email at WhiteBook@bpa.gov.

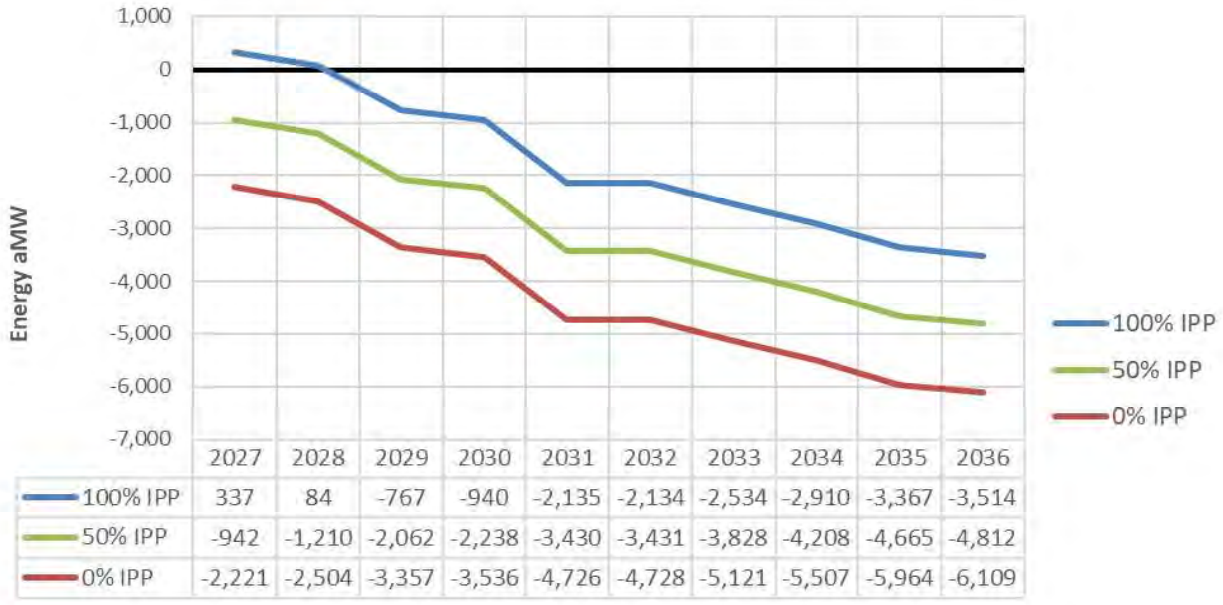
Table 3-8 PNW Regional Annual Energy Surplus/Deficit - Firm Water Conditions

Assuming 100% of Uncommitted IPP Generation is Available to the Region

Energy (aMW)	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Surplus/ Deficit	337	84	-767	-940	-2,135	-2,134	-2,534	-2,910	-3,367	-3,514

Table 3-9 shows the significant variability in PNW regional annual firm energy surplus/deficit forecasts depending on the level of uncommitted IPP generation available to the region. IPP generation is detailed in Tables 3-6 and 3-7.

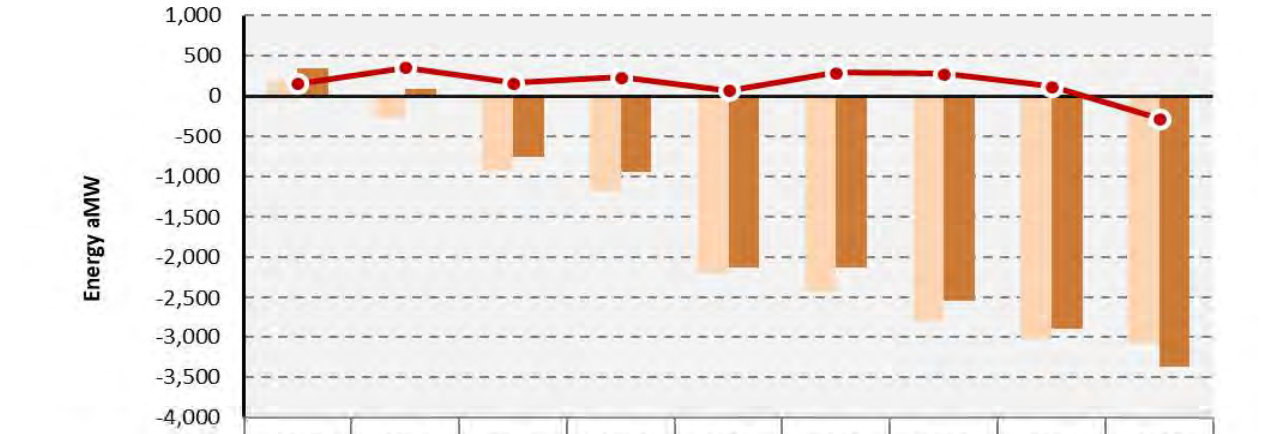
Table 3-9 PNW Regional Annual Energy Surplus/Deficit by Uncommitted IPP Generation %



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
100% IPP	337	84	-767	-940	-2,135	-2,134	-2,534	-2,910	-3,367	-3,514
50% IPP	-942	-1,210	-2,062	-2,238	-3,430	-3,431	-3,828	-4,208	-4,665	-4,812
0% IPP	-2,221	-2,504	-3,357	-3,536	-4,726	-4,728	-5,121	-5,507	-5,964	-6,109

Table 3-10 compares the 2026 White Book PNW regional annual firm energy surplus/deficit forecasts to that of the 2025 White Book. The comparison shows some changes. For example, the 2026 White Book shows OY 2027 to have roughly 150 aMW more energy surplus available, and this trend of slight improvement in overall inventory position continues through nearly the entire study period. This change is predominately driven by the TRL forecast decreases in the first half of the study period, more specifically in the new large industrial loads category.

Table 3-10 PNW Regional Annual Surplus/Deficit Comparison – Firm Water Conditions Assuming 100% Uncommitted IPP Generations available to the Region

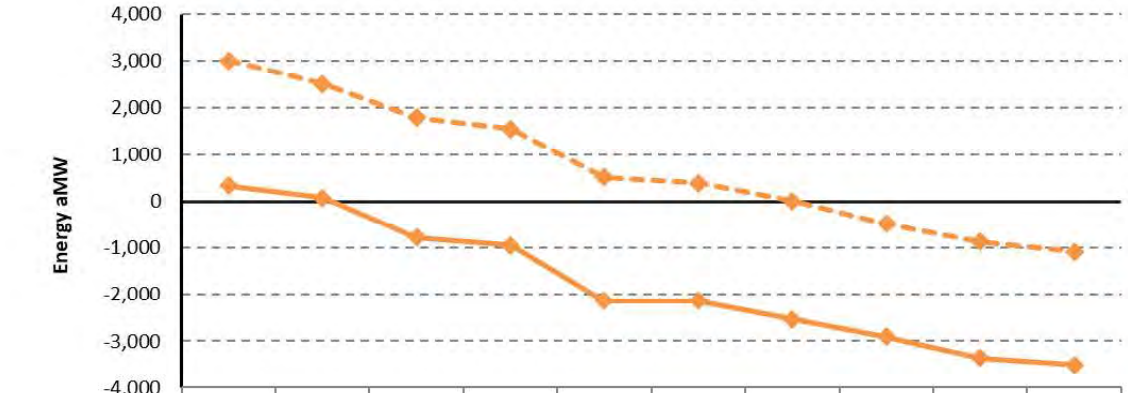


	2027	2028	2029	2030	2031	2032	2033	2034	2035
2025 White Book	186	-269	-928	-1169	-2200	-2422	-2808	-3026	-3091
2026 White Book	337	84	-767	-940	-2135	-2134	-2534	-2910	-3367
Delta	151	353	161	229	65	288	274	115	-275

Regional Annual Surplus/Deficit

Table 3-14 graphically presents the annual firm energy surplus/deficit forecasts for the PNW region under firm (P10) and median (P50) conditions. These forecasts assume 100% availability of the PNW uncommitted IPP generation to serve the region's loads. The regional annual energy surplus/deficit declines over the 10-year study period.

Table 3-14 PNW Regional Annual Surplus/Deficit – Firm & Median Water Conditions

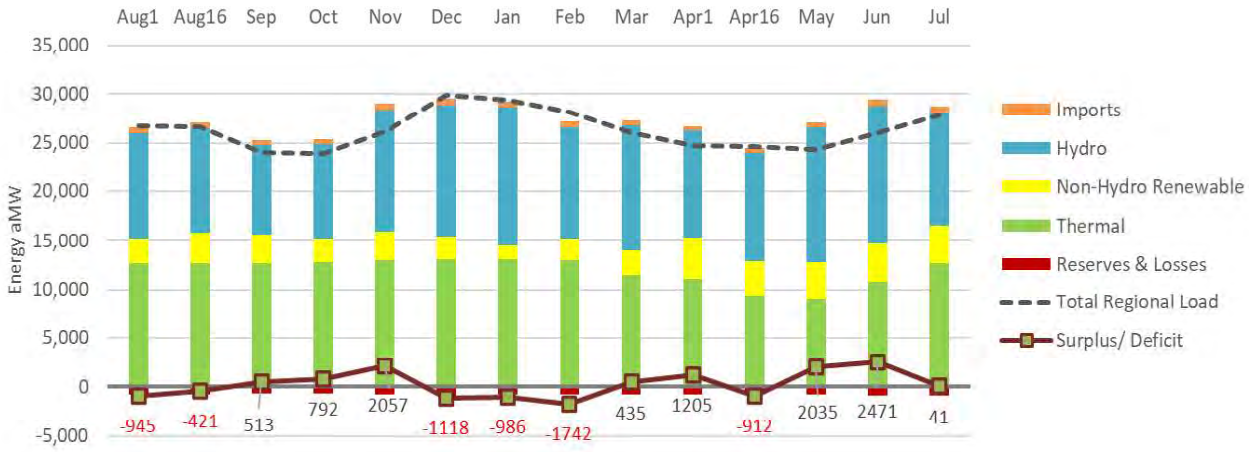


	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Energy P10	337	84	-767	-940	-2,135	-2,134	-2,534	-2,910	-3,367	-3,514
Energy P50	3017	2515	1798	1559	525	401	10	-478	-860	-1081

Regional Monthly Surplus/Deficit

Table 3-15 shows the monthly energy surplus/deficit forecast for OY 2027, accompanied with monthly total firm obligations and resources by category. Again, these forecasts assume 100% of uncommitted IPP generation serving the region. This monthly view shows how both metrics follow a similar monthly shape with most surplus months in late spring to the beginning of summer when hydro generation is high, and most deficits around the second half of April, before the runoff begins historically and as fish operations begin. The decrease in thermal generation between March through June is directly related to the CGS extended maintenance downtime for OY2027.

Table 3-15 PNW Regional Monthly Surplus/Deficit – OY2027 Firm Water Conditions



Conclusion

The PNW region is projected to have annual firm energy surpluses in the first two operating years, with surpluses declining and quickly becoming deficits. These grow into larger deficits going into the outyears, assuming that 100 % of the PNW region's uncommitted IPP generation is available to serve the region's load. Additionally, the supply of power within the region can change dramatically and quickly if those resources were to be used to serve loads outside of the region or retire early or unexpectedly. That's because of the full uncommitted nature of independent power producer generation to serve the region's load. Under the median (P50) water conditions, the PNW sees surpluses through OY 2033.

Notably, the region's retail load forecasts adjusted downwards significantly in the front half of the study period from 2025 White Book forecast. This was driven by the uncertainty of the new large single load category of the retail loads. The uncertainty continues and could drastically change these results.

Detailed surplus/deficit forecasts for all 30 historical water conditions are presented in Exhibit 5-3. Monthly and annual details for OY 2027 through OY 2036 are available upon request with the itemized list located in the Appendix.

SECTION 4: FEDERAL SYSTEM ANALYSIS EXHIBITS

Exhibit 4-1: Annual Energy – Federal System Surplus/Deficit:

Operating Years 2027 – 2036, Firm Water Conditions

Loads and Resources - Federal System Percentile
Operating Year: 2027 to 2036 Percentile: 10
2026 White Book (Energy Only) Report Date: **2/18/2026**
S274-WB-20260218-115822

	Energy-aMW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Firm Obligations										
1	**Load Following**	5419	5496	5652	5738	5800	5852	5894	5934	5968	6008
2	Preference Customers	5075	5146	5298	5373	5421	5465	5505	5542	5580	5614
3	Federal Agencies	150	154	161	167	181	188	190	193	195	195
4	USBR	194	197	194	199	199	199	199	199	194	199
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	573	586	583	588	590	590	590	589	589	589
7	Tier 1 Block	573	586	583	588	590	590	590	589	589	589
8	**Slice**	1426	1446	1415	1443	1424	1460	1450	1458	1451	1456
9	Slice Block	613	601	604	595	600	588	601	588	598	586
10	Slice Output from T1 System	812	845	810	848	824	872	849	869	854	870
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13	**Contract Deliveries**	380	316	316	289	234	234	234	234	234	234
14	Exports	312	305	305	278	225	225	225	225	225	225
15	Intra-Regional Transfers (Out)	68.2	10.7	10.7	10.7	9.44	9.44	9.44	9.44	9.44	9.44
16	**NR Obligation**	16.8	24.1	31.2	33.4	46.8	58.9	64.6	73.9	75.0	75.0
17	NR Rate Load	16.8	24.1	31.2	33.4	46.8	58.9	64.6	73.9	75.0	75.0
18	**Total Firm Obligations**	**7825**	**7880**	**8007**	**8103**	**8106**	**8206**	**8244**	**8300**	**8329**	**8372**
	Net Resources										
19	**Hydro**	6610	6643	6616	6653	6627	6664	6607	6639	6640	6646
20	Regulated Hydro - Net	6328	6356	6333	6375	6354	6388	6348	6380	6390	6387
21	Independent Hydro - Net	279	284	279	275	270	273	255	256	247	256
22	Small Hydro - Net	2.88	2.88	2.88	2.88	2.88	2.87	2.88	2.88	2.88	2.87
23	**Non-Hydro Renewable**	19.8	1.90	0	0	0	0	0	0	0	0
24	Wind - Net	19.8	1.90	0	0	0	0	0	0	0	0
25	Other - Net	0	0	0	0	0	0	0	0	0	0
26	**Thermal**	853	1116	841	1116	885	1270	1131	1270	1131	1270
27	Nuclear - Net	853	1116	841	1116	885	1270	1131	1270	1131	1270
28	**Contract Purchases**	255	163	161	154	143	77.9	77.3	77.8	77.6	77.9
29	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
30	Intra-Regional Transfers (In)	155	63.1	62.9	63.0	63.0	0	0	0	0	0
31	Non-Federal CER	84.0	83.8	82.5	75.0	64.6	61.2	60.9	61.1	61.1	61.2
32	Slice Transmission Loss Return	14.7	15.3	14.7	15.3	14.9	15.8	15.4	15.7	15.4	15.7
33	**Reserves & Losses**	-448	-453	-444	-453	-445	-456	-450	-455	-451	-455
34	Operating Reserves	0	0	0	0	0	0	0	0	0	0
35	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
36	Transmission Losses	-225	-230	-221	-230	-222	-233	-227	-232	-228	-232
37	Wheeling Loss (financial settlement)	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223
38	**Total Net Resources**	**7290**	**7471**	**7173**	**7470**	**7209**	**7556**	**7365**	**7532**	**7398**	**7539**
39	**Total Surplus/Deficit**	**-535**	**-408**	**-834**	**-633**	**-897**	**-650**	**-879**	**-767**	**-931**	**-834**

Exhibit 4-2: Monthly Energy – Federal System Surplus/Deficit: Operating Year 2027, Firm Water Conditions

Loads and Resources - Federal System Percentile
Operating Year: 2027 Percentile: 10
2026 White Book (Energy Only) Report Date: **2/18/2026**
S274-WB-20260218-115822

	Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
	Firm Obligations															
1	**Load Following**	5401	5364	4756	4655	5398	6170	6249	6037	5405	5047	5047	5029	5212	5703	5419
2	Preference Customers	4926	4882	4323	4392	5231	5986	6052	5842	5187	4648	4648	4551	4693	5119	5075
3	Federal Agencies	137	136	124	135	163	180	185	183	160	141	141	128	127	141	150
4	USBR	339	347	309	128	4.12	4.27	12.0	12.0	57.5	258	258	350	392	443	194
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	377	375	618	532	869	869	952	896	850	423	423	151	21.3	341	573
7	Tier 1 Block	377	375	618	532	869	869	952	896	850	423	423	151	21.3	341	573
8	**Slice**	1347	1359	1225	1226	1493	1674	1716	1548	1497	1223	1201	1282	1491	1393	1426
9	Slice Block	576	576	561	565	624	713	709	677	639	604	604	546	556	593	613
10	Slice Output from T1 System	771	784	664	661	869	961	1007	872	858	619	597	736	935	800	812
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
13	**Contract Deliveries**	757	723	571	343	345	346	318	318	314	314	314	314	314	314	380
14	Exports	371	349	331	305	305	305	305	305	305	305	305	305	305	305	312
15	Intra-Regional Transfers (Out)	387	374	240	38.5	39.8	41.3	13.2	13.4	9.44	9.44	9.44	9.44	9.44	9.44	68
16	**NR Obligation**	0	0	8.41	8.32	16.6	19.8	19.1	20.1	29.7	28.9	28.9	17.7	17.0	16.6	17
17	NR Rate Load	0	0	8.41	8.32	16.6	19.8	19.1	20.1	29.7	28.9	28.9	17.7	17.0	16.6	17
18	**Total Firm Obligations**	**7893**	**7833**	**7189**	**6775**	**8133**	**9091**	**9265**	**8830**	**8107**	**7047**	**7025**	**6805**	**7066**	**7779**	**7825**
	Net Resources															
19	**Hydro**	6147	6246	5150	4940	6638	7441	7870	6687	7108	5838	5645	6968	8053	6511	6610
20	Regulated Hydro - Net	5801	5910	4922	4709	6295	7175	7573	6527	6930	5612	5371	6549	7691	6211	6328
21	Independent Hydro - Net	344	333	226	228	340	262	294	158	175	223	272	416	359	297	279
22	Small Hydro - Net	2.63	2.63	2.63	2.67	2.84	3.19	3.21	3.05	3.10	3.09	3.09	2.83	2.72	2.63	2.9
23	**Non-Hydro Renewable**	22.6	33.8	31.5	25.3	36.2	27.6	5.28	8.73	10.0	17.9	15.1	16.2	16.0	15.6	20
24	Wind - Net	22.6	33.8	31.5	25.3	36.2	27.6	5.28	8.73	10.0	17.9	15.1	16.2	16.0	15.6	20
25	Other - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	**Thermal**	1116	1116	1116	1116	1116	1116	1116	1116	612	0	0	0	707	1116	853
27	Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	612	0	0	0	707	1116	853
28	**Contract Purchases**	601	596	726	162	186	242	264	225	191	161	161	95.7	104	102	255
29	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.0
30	Intra-Regional Transfers (In)	500	500	628	64.5	88.3	139	163	125	89.5	64.4	64.4	0	0	0	155
31	Non-Federal CER	84.9	79.6	85.2	85.4	81.6	85.3	81.8	84.0	85.5	84.9	84.9	81.8	84.9	85.3	84
32	Slice Transmission Loss Return	15.1	15.4	11.7	11.6	15.3	16.9	17.7	15.3	15.1	10.9	10.5	12.9	18.4	15.7	15
33	**Reserves & Losses**	-465	-468	-423	-401	-451	-474	-486	-452	-448	-395	-389	-426	-496	-460	-448
34	Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Transmission Losses	-242	-245	-200	-178	-228	-251	-263	-229	-226	-172	-166	-203	-273	-237	-225
37	Wheeling Loss (financial settlement)	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223	-223
38	**Total Net Resources**	**7422**	**7524**	**6600**	**5843**	**7525**	**8352**	**8769**	**7586**	**7473**	**5622**	**5432**	**6653**	**8385**	**7285**	**7290**
39	**Total Surplus/Deficit**	**-471**	**-309**	**-589**	**-932**	**-607**	**-738**	**-496**	**-1,244**	**-635**	**-1,425**	**-1,593**	**-151**	**1,319**	**-494**	**-535**

Exhibit 4-3: 30-Water Year Conditions Monthly Energy – Federal System Surplus/Deficit: Operating Year 2027

Federal Report Surplus Deficit By Water Year

Fiscal Year 2027

2026 White Book (Energy Only) Report Date: **3/5/2026**

S274-WB-20260218-115822

	Energy-aMW - Surplus Deficit	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Aug1	Aug16	Sep	Avg
1	1989 Federal Report Surplus Deficit	-932	-581	247	72.3	-787	368	102	1759	1916	1605	17.6	-603	-239	-412	174
2	1990 Federal Report Surplus Deficit	-506	-93.0	2144	1203	2087	1187	1300	2507	908	4474	3325	1843	1507	-232	1501
3	1991 Federal Report Surplus Deficit	-1052	1688	2352	2889	3458	2016	1676	1051	1826	3381	4486	2565	2146	-588	2008
4	1992 Federal Report Surplus Deficit	-850	-94.5	-904	-362	-751	-481	-1425	-850	-51.9	1319	-751	-644	-189	-792	-439
5	1993 Federal Report Surplus Deficit	-931	-412	-937	-1000	-2289	-808	-706	-2229	2616	2332	1732	166	285	-320	-88.2
6	1994 Federal Report Surplus Deficit	-1019	-244	-931	-822	-1095	-199	-2051	-519	-151	1814	-412	-257	-90.7	-751	-437
7	1995 Federal Report Surplus Deficit	-892	-502	-469	655	1634	1512	-617	-628	1126	4286	1964	548	-58.2	-158	723
8	1996 Federal Report Surplus Deficit	291	2746	6120	5927	6203	6191	2852	3678	3384	6003	4903	2265	1480	84.0	3905
9	1997 Federal Report Surplus Deficit	-577	55.4	2386	6015	6111	5445	3799	4848	5636	6556	5236	2658	2252	767	3688
10	1998 Federal Report Surplus Deficit	1596	1382	1250	1345	1477	1297	-898	-1107	5507	4632	2313	1335	459	-324	1704
11	1999 Federal Report Surplus Deficit	-794	-607	1389	4326	4003	4446	984	2727	1894	5532	5458	3051	4045	51.7	2591
12	2000 Federal Report Surplus Deficit	-245	1547	2970	2501	2051	1951	2423	2613	1907	1268	1745	1344	285	-697	1526
13	2001 Federal Report Surplus Deficit	-797	-493	-460	-1005	-1244	-1031	-1879	-2999	-898	206	-494	-473	-380	-1103	-844
14	2002 Federal Report Surplus Deficit	-1271	-861	-738	-496	-293	-635	44.9	1794	1403	4966	3714	-133	-639	-785	460
15	2003 Federal Report Surplus Deficit	-834	-36.5	-615	-242	-1460	696	85.2	437	852	3865	-362	-396	-108	-1024	75.8
16	2004 Federal Report Surplus Deficit	-798	44.4	-6.23	164	-231	-598	-666	-759	352	2476	219	-371	621	-21.7	84.3
17	2005 Federal Report Surplus Deficit	14.7	85.9	1520	982	346	366	-1730	-620	779	1833	1259	61.4	-173	-971	421
18	2006 Federal Report Surplus Deficit	-634	-48.8	1181	3238	2948	1276	2810	1451	4569	4909	1445	-550	-522	-1040	1610
19	2007 Federal Report Surplus Deficit	-689	-329	1356	2406	1438	2879	1772	656	1461	2679	1106	-296	-784	-1325	971
20	2008 Federal Report Surplus Deficit	-550	20.7	636	194	47.6	-107	-1153	-1423	2757	5644	3039	148	762	-141	898
21	2009 Federal Report Surplus Deficit	-578	-557	139	1769	-646	69.6	1064	653	1467	2340	570	-538	-632	-805	343
22	2010 Federal Report Surplus Deficit	-660	-158	-380	-148	-1623	-1474	-1109	-2098	-510	4708	1739	-66.0	-326	-728	-80.7
23	2011 Federal Report Surplus Deficit	-705	-505	1274	4381	4512	3000	4815	465	2941	6448	6582	2170	1829	-156	2692
24	2012 Federal Report Surplus Deficit	-610	-363	880	2470	1480	2919	4026	4105	3311	5363	5733	2775	1391	-420	2248
25	2013 Federal Report Surplus Deficit	-503	235	3126	1140	134	147	3417	996	2236	3417	2101	904	533	-242	1233
26	2014 Federal Report Surplus Deficit	-606	-204	111	1560	255	2934	3004	868	2686	3867	2809	420	495	-187	1309
27	2015 Federal Report Surplus Deficit	-715	365	2359	3250	3249	4590	847	-1593	-910	894	-1222	-307	-343	-585	870
28	2016 Federal Report Surplus Deficit	-550	-708	372	916	53.7	2135	1708	3079	2441	1618	-830	17.0	128	-365	632
29	2017 Federal Report Surplus Deficit	113	2665	623	3594	3617	6792	4759	3668	5086	6087	1782	331	44.8	-756	2824
30	2018 Federal Report Surplus Deficit	-655	-944	378	3715	4520	3005	2210	1357	5091	3974	397	-493	-310	-778	1657

SECTION 5: PACIFIC NORTHWEST REGIONAL ANALYSIS EXHIBITS

Exhibit 5-1: Annual Energy – PNW Regional Surplus/Deficit: Operating Years 2027 – 2036, Firm Water Conditions

Loads and Resources - Pacific Northwest Region Percentile
Operating Year: 2027 to 2036 Percentile: 10
2026 White Book (Energy Only) Report Date: **2/18/2026**
S274-WB-20260218-115822

	Energy-aMW	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Regional Loads										
1	**Retail Loads**	25626	26129	26668	27218	27806	28325	28808	29228	29604	29912
2	Federal Agency	152	156	163	169	183	190	192	195	197	198
3	USBR	194	197	194	199	199	199	199	199	194	199
4	Cooperative	3575	3794	4065	4396	4763	5088	5363	5590	5778	5902
5	Municipality	2601	2641	2674	2706	2737	2760	2775	2787	2797	2810
6	Public Utility District	5150	5249	5328	5374	5419	5460	5507	5550	5593	5630
7	Investor-Owned Utility	13902	14041	14193	14324	14454	14578	14721	14857	14994	15123
8	Direct-Service Industry	51.3	51.3	51.3	51.3	51.3	51.3	51.3	51.3	51.3	51.3
9	Federal Diversity	0	0	0	0	0	0	0	0	0	0
10	**Exports**	794	787	785	756	456	360	361	361	361	360
11	Canada	305	305	305	278	225	225	225	225	225	225
12	East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13	Pacific Southwest	488	481	479	477	230	134	135	135	135	134
14	**Total Regional Loads**	**26420**	**26916**	**27454**	**27974**	**28262**	**28686**	**29169**	**29589**	**29965**	**30273**
	Regional Resources										
15	**Hydro**	12009	12094	12013	12038	11960	12047	12185	12177	12215	12182
16	Regulated Hydro - Net	10838	10910	10841	10868	10803	10880	10990	10984	11034	10989
17	Independent Hydro - Net	928	940	928	926	913	925	952	950	938	949
18	Small Hydro - Net	244	243	244	244	244	243	244	244	244	243
19	**Non-Hydro Renewable**	2907	2906	2908	2907	2891	2902	2907	2907	2907	2905
20	Wind - Net	2240	2238	2240	2240	2224	2235	2240	2240	2240	2238
21	Solar - Net	510	510	510	510	510	510	510	510	510	510
22	Other - Net	157	158	158	157	157	157	157	157	157	157
23	**Thermal**	12035	12198	11950	12280	11920	12352	12295	12349	12227	12428
24	Nuclear - Net	853	1116	841	1116	885	1270	1131	1270	1131	1270
25	Coal - Net	3049	2955	2981	3034	2948	2962	3034	2948	2966	3030
26	Natural Gas - Net	5371	5373	5372	5368	5371	5372	5371	5371	5371	5372
27	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
28	Biofuel - Net	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
29	Cogeneration - Net	2737	2729	2730	2737	2691	2722	2734	2734	2734	2731
30	**Imports**	600	605	609	613	132	38.7	38.8	38.9	39.0	39.2
31	Canada	38.8	38.8	38.8	38.8	36.7	36.5	36.4	36.4	36.4	36.5
32	Inland Southwest	513	517	521	525	93.6	0	0	0	0	0
33	Pacific Southwest	48.7	48.9	49.2	49.2	2.15	2.25	2.35	2.48	2.59	2.70
34	**Reserves & Losses**	-795	-802	-793	-803	-776	-789	-791	-792	-790	-795
35	Operating Reserves	0	0	0	0	0	0	0	0	0	0
36	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
37	Transmission Losses	-795	-802	-793	-803	-776	-789	-791	-792	-790	-795
38	**Total Regional Resources**	**26757**	**27000**	**26687**	**27034**	**26127**	**26552**	**26634**	**26679**	**26598**	**26759**
39	**Total Surplus/Deficit**	**337**	**84**	**-767**	**-940**	**-2,135**	**-2,134**	**-2,534**	**-2,910**	**-3,367**	**-3,514**

Exhibit 5-2: Monthly Energy – PNW Regional Surplus/Deficit: Operating Year 2027, Firm Water Conditions

Loads and Resources - Pacific Northwest Region Percentile
Operating Year: 2027 Percentile: 10
2026 White Book (Energy Only) Report Date: **2/19/2026**
S274-WB-20260218-115822

	Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
	Regional Loads															
1	**Retail Loads**	25867	25654	23086	23246	25339	29180	28863	27513	25401	23794	23794	23423	25122	26802	25626
2	Federal Agency	141	140	127	138	163	180	185	183	160	145	145	132	131	145	152
3	USBR	339	347	309	128	4.12	4.27	12.0	12.0	57.5	258	258	350	392	443	194
4	Cooperative	3544	3525	3215	3173	3473	3862	3918	3752	3517	3400	3400	3438	3703	3921	3575
5	Municipality	2400	2379	2259	2406	2729	3113	3119	3012	2764	2476	2476	2290	2272	2403	2601
6	Public Utility District	4873	4838	4479	4723	5324	6042	6119	5774	5228	4849	4849	4607	4766	5060	5150
7	Investor-Owned Utility	14520	14375	12646	12625	13594	15928	15458	14728	13623	12614	12614	12556	13808	14780	13902
8	Direct-Service Industry	50.2	50.1	50.9	51.8	52.2	51.9	52.3	52.0	51.5	51.9	51.9	50.4	50.1	50.1	51
9	Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Exports**	864	989	924	642	777	665	498	623	671	959	863	901	948	1042	794
11	Canada	315	295	305	305	305	305	305	305	305	305	305	305	305	305	305
12	East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.0
13	Pacific Southwest	548	693	618	336	471	359	192	317	365	653	557	595	642	736	488
14	**Total Regional Loads**	**26731**	**26643**	**24010**	**23888**	**26115**	**29844**	**29361**	**28137**	**26072**	**24752**	**24657**	**24325**	**26069**	**27843**	**26420**
	Regional Resources															
15	**Hydro**	10905	10573	9103	9784	12377	13414	14076	11385	12710	11049	11024	13842	14056	11488	12009
16	Regulated Hydro - Net	9583	9287	8089	8799	11076	12362	12966	10520	11734	9920	9773	12239	12686	10224	10838
17	Independent Hydro - Net	997	963	770	822	1172	927	986	733	815	849	969	1200	947	859	928
18	Small Hydro - Net	325	323	244	163	128	126	124	132	162	280	282	403	422	405	244
19	**Non-Hydro Renewable**	2411	3185	2867	2346	2933	2271	1454	2172	2525	4089	3558	3866	3942	3862	2907
20	Wind - Net	1593	2340	2162	1744	2430	1871	1047	1663	1897	3314	2802	3026	3049	2954	2240
21	Solar - Net	658	686	548	443	344	242	259	351	470	619	599	692	759	727	510
22	Other - Net	159	159	157	160	159	159	148	158	158	157	157	149	134	181	157
23	**Thermal**	12680	12687	12745	12777	13004	13098	13057	12992	11525	11109	9388	8905	10759	12677	12035
24	Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	612	0	0	0	707	1116	853
25	Coal - Net	3075	3075	3079	3080	3077	3081	3082	3081	2900	2962	2765	3097	3095	3078	3049
26	Natural Gas - Net	5585	5592	5654	5716	5851	5921	5914	5853	5804	5484	4427	3366	4262	5587	5371
27	Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Biofuel - Net	23.6	23.6	25.4	26.7	27.0	24.6	24.3	24.4	27.0	25.4	25.4	27.2	25.0	25.8	26
29	Cogeneration - Net	2880	2880	2871	2838	2933	2955	2921	2919	2182	2638	2171	2414	2670	2870	2737
30	**Imports**	599	599	522	492	678	780	614	614	518	465	465	514	677	731	600
31	Canada	20.8	20.8	15.8	22.0	38.9	49.3	62.3	70.8	62.7	30.2	30.2	28.9	38.6	27.0	39
32	Inland Southwest	577	577	504	468	457	494	463	479	454	433	433	483	637	702	513
33	Pacific Southwest	1.48	1.48	1.48	1.65	182	237	89.0	64.9	1.65	1.65	1.65	1.65	1.65	1.65	49
34	**Reserves & Losses**	-808	-822	-714	-719	-820	-837	-826	-769	-772	-756	-692	-768	-895	-874	-795
35	Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Transmission Losses	-808	-822	-714	-719	-820	-837	-826	-769	-772	-756	-692	-768	-895	-874	-795
38	**Total Regional Resources**	**25786**	**26222**	**24523**	**24680**	**28172**	**28726**	**28374**	**26394**	**26507**	**25958**	**23745**	**26359**	**28540**	**27884**	**26757**
39	**Total Surplus/Deficit**	**-945**	**-421**	**513**	**792**	**2,057**	**-1,118**	**-986**	**-1,742**	**435**	**1,205**	**-912**	**2,035**	**2,471**	**41**	**337**

Exhibit 5-3: 30-Water Year Conditions Monthly Energy – PNW Regional Surplus/Deficit: Operating Year 2027

Regional Report Surplus Deficit By Water Year
Fiscal Year 2027
2026 White Book (Energy Only) Report Date: **3/5/2026**
S274-WB-20260218-115822

Energy-aMW - Surplus Deficit	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Aug1	Aug16	Sep	Avg
1 1989 Regional Report Surplus Deficit	738	1,928	85	-481	-656	2,051	4,558	6,456	5,732	4,592	1,412	-1,268	-398	1,199	1,777
2 1990 Regional Report Surplus Deficit	728	3,200	4,047	2,366	4,224	3,610	6,411	7,093	4,040	8,940	7,091	2,695	2,245	1,368	4,057
3 1991 Regional Report Surplus Deficit	280	6,627	3,885	4,033	6,995	4,833	6,957	4,111	5,583	7,268	9,233	4,047	3,418	946	4,893
4 1992 Regional Report Surplus Deficit	-26	2,219	-1,530	-879	-76	490	1,098	414	1,326	2,375	-674	-1,888	-947	119	215
5 1993 Regional Report Surplus Deficit	-49	1,567	-2,263	-2,720	-3,258	315	3,210	-1,553	7,228	5,031	4,369	385	439	1,337	1,090
6 1994 Regional Report Surplus Deficit	-124	1,391	-1,830	-1,708	-1,269	1,541	545	2,011	1,938	3,653	59	-1,141	-668	374	366
7 1995 Regional Report Surplus Deficit	114	1,460	-469	761	4,173	4,357	2,604	668	4,641	8,826	4,800	855	-174	1,604	2,665
8 1996 Regional Report Surplus Deficit	2,552	8,353	10,155	9,197	11,758	11,417	9,440	9,588	8,309	11,018	9,729	3,710	2,333	2,120	8,067
9 1997 Regional Report Surplus Deficit	1,034	2,770	4,186	9,701	10,789	10,950	10,516	10,911	11,867	12,417	10,668	4,834	3,827	3,853	7,750
10 1998 Regional Report Surplus Deficit	5,527	5,348	2,301	2,515	3,787	4,195	2,858	694	10,996	9,364	5,575	2,110	586	1,520	4,525
11 1999 Regional Report Surplus Deficit	277	1,980	2,932	6,898	7,553	8,804	5,703	6,860	6,570	11,718	11,356	5,563	6,531	2,086	6,036
12 2000 Regional Report Surplus Deficit	1,471	6,160	5,432	3,686	4,395	4,606	8,435	7,322	5,893	4,259	4,515	1,873	304	750	4,168
13 2001 Regional Report Surplus Deficit	414	1,123	-1,484	-2,807	-1,794	-698	155	-3,887	337	1,203	-53	-1,568	-970	-359	-601
14 2002 Regional Report Surplus Deficit	-686	1,327	-1,177	-1,018	322	375	4,212	5,679	5,027	10,040	7,883	-444	-1,272	507	2,217
15 2003 Regional Report Surplus Deficit	-71	1,821	-1,568	-324	-1,308	2,712	3,772	2,683	3,405	7,390	256	-1,466	-751	-74	1,197
16 2004 Regional Report Surplus Deficit	766	2,344	-194	-395	331	547	3,052	986	2,713	5,157	1,503	-1,159	1,009	2,227	1,407
17 2005 Regional Report Surplus Deficit	1,760	2,509	2,603	1,269	1,138	1,853	834	1,286	3,342	3,924	2,850	-650	-828	-159	1,789
18 2006 Regional Report Surplus Deficit	574	2,188	1,819	5,618	5,729	3,709	8,512	5,168	9,965	10,119	3,675	-1,400	-1,220	-57	4,051
19 2007 Regional Report Surplus Deficit	269	3,208	2,317	3,176	3,158	7,039	7,264	3,483	4,958	5,804	3,086	-1,070	-1,663	-506	3,036
20 2008 Regional Report Surplus Deficit	725	1,976	1,096	-717	557	981	1,110	-1,078	7,730	10,835	7,164	79	1,062	1,482	2,711
21 2009 Regional Report Surplus Deficit	503	1,642	-465	2,296	-479	1,009	5,182	3,428	5,139	5,931	2,334	-1,161	-1,224	320	1,783
22 2010 Regional Report Surplus Deficit	551	2,395	-996	-333	-1,963	-1,044	1,757	-1,682	1,223	9,762	4,863	-281	-641	834	1,243
23 2011 Regional Report Surplus Deficit	510	1,798	2,157	7,044	8,038	7,005	12,026	3,766	7,882	12,625	13,039	4,379	3,257	1,900	6,126
24 2012 Regional Report Surplus Deficit	771	1,903	1,034	3,523	3,403	6,456	10,454	9,895	8,127	10,405	11,155	4,328	1,986	1,061	5,099
25 2013 Regional Report Surplus Deficit	964	3,397	5,011	941	770	1,517	9,521	3,985	6,391	7,171	4,739	962	545	1,631	3,342
26 2014 Regional Report Surplus Deficit	830	1,775	-515	1,857	1,351	6,521	8,440	4,135	7,114	7,778	6,668	472	538	1,380	3,470
27 2015 Regional Report Surplus Deficit	680	3,458	4,254	4,958	6,798	8,627	5,555	-1,002	-463	1,882	-1,466	-1,574	-1,298	512	2,476
28 2016 Regional Report Surplus Deficit	470	1,570	964	1,257	1,622	5,309	6,952	7,469	6,054	3,366	-326	-608	-231	976	2,333
29 2017 Regional Report Surplus Deficit	2,852	7,315	692	4,434	7,347	12,856	12,197	8,793	10,902	11,801	4,387	327	-272	590	6,115
30 2018 Regional Report Surplus Deficit	880	1,758	718	5,635	8,231	6,314	7,927	5,792	10,213	7,839	2,167	-1,293	-947	441	4,127

APPENDIX – REPORTS AVAILABLE UPON REQUEST

Please send request via email to WhiteBook@bpa.gov, and allow three to five business days for turn-around time.

A. Annual Energy (aMW) – Operating Years 2027 – 2036
B. Monthly Energy (aMW) – Operating Years 2027 – 2036

	Report #	
Report Descriptions	**Annual**	**Monthly**
Federal Report Surplus/Deficit	1A	1B
Regional Report Surplus/Deficit	2A	2B
Regional Total Retail Load	3A	3B
Regional Exports	4A	4B
Regional Imports	5A	5B
Regional Intra-Regional Transfer	6A	6B
BPA Sales to Preference and Legacy Customers	7A	7B
Regional Regulated Hydro	8A	8B
Regional Independent Hydro	9A	9B
Regional Small Hydro	10A	10B
Regional Non-Hydro Renewable – Wind	11A	11B
Regional Non-Hydro Renewable – Solar	12A	12B
Regional Non-Hydro Renewable – Other	13A	13B
Regional Thermal – Nuclear	14A	14B
Regional Thermal – Coal	15A	15B
Regional Thermal – Natural Gas	16A	16B
Regional Thermal – Petroleum	17A	17B
Regional Thermal – Biofuel	18A	18B
Regional Thermal – Cogeneration	19A	19B
Non-Federal CER Deliveries to BPA	20A	20B
Federal Report Surplus/Deficit by 30 Water Year	--	21B
Regional Report Surplus/Deficit by 30 Water Year	--	22B

BONNEVILLE POWER ADMINISTRATION
DOE/BP-5477 ▪ April 2026

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

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

Exhibit 3-02:
Department Export Authorization EA-521 (Oct. 21, 2025)

United States
Department of Energy

Office of Electricity

Halia Energy LLC

OE Docket No. EA-521

Order Authorizing Electricity Exports to Canada

Order No. EA-521

April 15, 2026

Halia Energy LLC
Order No. EA-521
Authorizing Electricity Exports to Canada

I. BACKGROUND

The Department of Energy (DOE or Department) regulates electricity exports from the United States to a foreign country in accordance with Federal Power Act (FPA) § 202(e) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. §§ 205.300 *et seq.*). This authority was transferred to DOE under §§ 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)). On November 20, 2025, the Federal Permitting Program functions were reorganized under the Office of Electricity and on January 8, 2026, the authority to regulate export authorizations pursuant to 202(e) of the FPA was delegated to the DOE's Assistant Secretary for Electricity by Redelegation Order No. S3-DEL-OE1-2026.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA § 202(e), DOE "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department "may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate." *Id*.

A. Application for Export Authorization

Halia Energy LLC (Halia Energy or the Applicant) is requesting authorization to export electric energy to Canada. On February 25, 2025, Halia Energy filed an application (Application or App.) requesting export authority for a five-year term. App. at 1.

According to the Application, Halia Energy is "a Delaware limited liability company" that is "a direct, wholly owned subsidiary of Halia Energy US ApS, a corporation organized under the laws of Denmark." *Id* at 1. Halia Energy represents that it is a "power marketer authorized by the Federal Energy Regulatory Commission ('FERC') to make sales of electric power at wholesale in interstate commerce at market-based rates" and that Halia Energy does not "own, operate, or control electric generation facilities or transmission facilities, and does not have a franchised service area." *Id* at 2. Halia Energy represents that it "is a power marketer that will export electricity purchased from electric utilities, federal power marketing agencies, qualifying cogeneration, and small power production facilities, independent power producers, and other sellers" and therefore the applicant "has no "transmission system" of its own on which power exports could have a reliability or stability impact. *Id* at 4.

The applicant further affirms that "in making the necessary commercial arrangements and obtaining transmission capacity necessary to export electricity under the authorization requested herein, Halia Energy will comply with existing industry procedures for obtaining transmission capacity, including reserving transmission service in accordance with FERC's Open-Access Same-Time Information System and scheduling delivery of the export with the appropriate Regional Transmission Organization(s) or Independent System Operator(s) and/or Balancing Authority Areas." *Id* at 5. The applicant notes they will "schedule [its] exports from the U.S. in compliance with all applicable reliability criteria, standards and guides as are set out by the North American Electricity Reliability Corporation ('NERC') (or any successor organization), the North American Energy Standards Board (or any successor organization), and regional reliability councils and as applied by U.S. transmission providers." *Id* at 5.

B. Procedural History

On February 25, 2025, Halia Energy filed an application with DOE for export authority for a five-year term. *Id* at 1. On June 16, 2025, DOE published notice of Halia Energy's Application in the Federal Register (90 Fed. Reg. 25253) and asked for any interested parties to submit comments on the Application by July 16, 2025.

C. Public Comments

No public comments were received.

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States …." 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g.*, *BP Energy Co.*, Order No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, Order No. EA-314-A, at 2 (May 3, 2012), Order No. EA-314-B, at 2 (Feb. 28, 2017), *renewed,* Order No. EA-314-C, at 4 (Dec. 20, 2021).

Under the second exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would … impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g.*, Order No. EA-314-C, at 4.

A. Halia Energy Will Not Impair the Sufficiency of the Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged the FERC to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government's commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers[1] and to ensure that these markets are functioning properly.[2] As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets relevant to this export authorization analysis are flawed and result in uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,[3] DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.[4] Reliability oversight is addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added

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[1] *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

[2] *See, e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[3] A related reliability analysis follows in the next section of this Order.

[4] This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified the NERC in 2006 to develop and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). FERC approves these standards, at which point they become mandatory and enforceable. NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,[5] all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 "establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act."[6] Requirement R1 states that "[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."[7] Reliability oversight is designed through coordinated efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.[8] Reliability Standard IRO-014-3 R1 provides that "[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability."[9]

DOE finds that NERC's FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement

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[5] The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

[6] Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

[7] *Id.* ¶ B.R1.

[8] *See* Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

[9] *Id.* ¶ B.R1.

of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by Halia Energy's proposed export authorization.

DOE's sufficiency of supply findings are further supported by the fact that power marketers, such as Halia Energy, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically integrated utility[10] with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility's native load obligations and reserve margins. As explained in DOE's notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

> The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.
>
> Since marketers generally could not be seen as having any "native load" requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54900 (Nov. 2, 1994). Power marketers do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

In sum, market mechanisms and reliability oversight protect against the possibility that Halia Energy LLC's exports would jeopardize domestic sufficiency of supply. Therefore, an export by Halia Energy would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

B. Halia Energy's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the United States Electric Transmission System

[10] The Supreme Court of the United States has explained: "In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems…[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were 'bundled,' meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent." *New York v. FERC*, 535 US 1, 5 (2002).

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area."[11]

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 ("Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions"), R2 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements"), and R3 ("Each Transmission

[11] EOP-011-1 (Emergency Operations), at ¶ B.R2.

Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1").

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any export will not cause an operational reliability problem. Therefore, Halia Energy's export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the United States' electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE's reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.*, http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit[12] to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted with Presidential permit applications,[13] DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (*see* Order below, Section VII, paragraph (A)). In its application, Halia Energy committed to complying with all reliability limits on border facilities. *See* App. at 5. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC's reliability enforcement.

III. FINDINGS AND DECISION

A. Halia Energy Meets the Statutory Requirements to Export Electric Energy to Canada

[12] DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

[13] *See, e.g.*, *AEP Tex. Cent. Co*., Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, Order No. PP-305, at 2-4 (Nov. 17, 2008).

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the United States electric power supply system. DOE has determined that the export of electric energy to Canada by Halia Energy, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. Halia Energy Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

Halia Energy's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq*. DOE's NEPA Implementing Procedures (June 2025) set forth this categorical exclusion, codified as "B4.2," as follows:

> Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B, § B4.2.

DOE has determined that actions in this category do not normally have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.102(a).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal." 10 C.F.R. § 1021.102(b)(2). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; and unresolved conflicts concerning alternative uses of available resources." *Id*. DOE finds that granting Halia Energy's request for export authorization does not present such extraordinary circumstances. Halia Energy seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application.

C. Conclusion

DOE grants Halia Energy's request for export authorization. Halia Energy is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order. The authorization shall be effective for a five (5) year term consistent with DOE's standard term for new electricity export authorizations.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Office of Electricity via email at *electricity.exports@hq.doe.gov*. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order or continuing to export after the expiration of such an order may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects Halia Energy to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor Halia Energy compliance with these terms and conditions, including the requirement in paragraph G of this Order that Halia Energy create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject Halia Energy to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide open access transmission service across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that Halia Energy is authorized to export electric energy to Canada under the following terms and conditions:

(A) The electric energy exported by Halia Energy pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:[14, 15]

Owner	**Location**	**Voltage**	**Permit No.**[16]
Bangor Hydro-Electric Company	Baileyville, ME	345 kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230 kV	PP-64
Bonneville Power Administration (BPA)	Blaine, WA	2x 500 kV	PP-10
	Nelway, WA	230 kV	PP-36
	Nelway, WA	230 kV	PP-46

[14] This Order authorizes the export of electricity over any "authorized international transmission facility," which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

[15] The Applicant submitted a list identifying currently authorized transmission facilities (Attachment 1 of the Application). However, as information about some of those facilities may have changed since the Application was submitted, the table of transmission facilities in this Order may differ from the Applicant's submission to reflect those changes.

[16] These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

CHPE, LLC	Champlain, NY	±230 kV DC	PP-481
Eastern Maine Electric Cooperative	Calais, ME	69 kV	PP-32
International Transmission Company	Detroit, MI	230 kV	PP-230
	Marysville, MI	230 kV	PP-230
	St. Claire, MI	230 kV	PP-230
	St. Claire, MI	345 kV	PP-230
Lake Erie Connector Transmission, LLC	Erie County, PA	320 kV	PP-412[17]
Long Sault, Inc.	Massena, NY	2x 115 kV	PP-24
Maine Electric Power Company	Houlton, ME	345 kV	PP-43
Minnesota Power, Inc.	International Falls, MN	115 kV	PP-78
Minnesota Power, Inc.	Roseau County, MN	500 kV	PP-398
Minnkota Power Cooperative	Roseau County, MN	230 kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230 kV	PP-399
NECEC Transmission LLC	Beattie Twp, ME	±320 kV	PP-438[18]
New York Power Authority	Massena, NY	765 kV	PP-56
	Massena, NY	2x 230 kV	PP-25
	Niagara Falls, NY	2x 345 kV	PP-74
	Devils Hole, NY	230 kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230 kV	PP-190
Northern States Power Company	Red River, ND	230 kV	PP-45
	Roseau County, MN	500 kV	PP-63
	Rugby, ND	230 kV	PP-231

[17] These transmission facilities have been authorized but not yet constructed or placed into operation.

[18] These transmission facilities have been authorized but not yet constructed or placed into operation.

Sea Breeze Olympic Converter LP	Port Angeles, WA	±450 kV DC	PP-299[19]
TDI New England	Alburgh, VT	±320 kV DC	PP-400[20]
Vermont Electric Power Co.	Derby Line, VT	120 kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450 kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Fort Fairfield, ME	69 kV	PP-497
	Madawaska, ME	138 kV	PP-498
	Easton, ME	7.2 kV	PP-499
	Baileyville, ME	345kV	PP-500

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

(a) Exports by Halia Energy made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that Halia Energy may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.

(b) Exports by Halia Energy made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous transmission rate of 15 MW. The gross amount of energy that Halia Energy may export over the PP-32 facilities shall not exceed 7,500 MWH annually.

(c) Exports by Halia Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481-2 (issued to CHPE, LLC) to exceed an instantaneous transmission rate of 1,250 MW.

(d) Exports by Halia Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).

[19] These transmission facilities have been authorized but not yet constructed or placed into operation.

[20] These transmission facilities have been authorized but not yet constructed or placed into operation.

(e) Exports by Halia Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412-1 (issued to Lake Erie Connector Transmission, LLC) to exceed an instantaneous transmission rate of 1,000 MW.

(f) Exports by Halia Energy made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities authorized by Presidential Permits PP-43 (issued to Maine Electric Power Company) and PP-500 (issued to Bangor Hydro-Electric) to exceed 550 MW.

(g) Exports by Halia Energy made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits PP-497 and PP-498 (issued to Versant Power) to exceed a coincident, instantaneous transmission rate of 134 MW.

(h) Exports by Halia Energy made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 100 MW. Exports by Halia Energy may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by Halia Energy cause the total exports on the PP-78-1 facilities to exceed 150 MW.

(i) Exports made by Halia Energy pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 750 MW.

(j) Exports by Halia Energy made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power Company), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power Company, d/b/a Excel Energy Inc. (Xcel)), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1,050 MW on a non-firm basis.

(k) Exports by Halia Energy made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that Halia Energy may export over the PP-66 facilities shall not exceed 50,000 MWH annually.

(l) Exports by Halia Energy made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1,000 MW.

(m) Exports by Halia Energy made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74 (issued to NYPA), and PP-190 (issued to Niagara Mohawk Power Corp.) to exceed a combined instantaneous transmission rate of 1,650 MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that Halia Energy may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

(n) Exports by Halia Energy made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the 230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

(o) Exports by Halia Energy made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76-1, as amended (issued to the Vermont Electric Transmission Company):

Exports Through	NEPOOL Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

(p) Exports by Halia Energy made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-399 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.

(q) Exports by Halia Energy made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission LLC) shall not exceed an instantaneous transmission rate of 1,200 MW.

(r) Exports by Halia Energy made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299 (issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

(s) Exports by Halia Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.

(t) Exports by Halia Energy made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-6 (issued to Vermont Transco LLC) to exceed an instantaneous transmission rate of 250 MW.

(B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(l), (m), and (n) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to Halia Energy.

(C) Halia Energy shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.

(D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.

(E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.

(F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.

(G) Halia Energy shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. Halia Energy shall collect and

submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

(H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.

(I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.

(J) Halia Energy has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.

(K) This authorization shall be effective as of April 2, 2026 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least one hundred and twenty (120) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in Halia Energy's authority to export electricity.

Issued in Washington, DC, on April 15, 2026.

CATHERINE JEREZA

Digitally signed by CATHERINE JEREZA
Date: 2026.04.15 19:10:46 -04'00'

Catherine Jereza
Assistant Secretary
Office of Electricity
U.S. Department of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

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

Exhibit 3-03:
NOAA June 10, 2026, Dalles Dam Forecast

Northwest River Forecast Center

Water Supply Forecasts

Choose Date: 06/10/2026 Archive: Water Year

COLUMBIA - THE DALLES DAM (TDAO3)
Forecasts for Water Year 2026

Official Water Supply

ESP with 10 Days QPF **Ensemble:** 2026-06-10 **Issued:** 2026-06-10

Forecast Period	Forecasts Are in KAF 90 %	50 %	% Average	10 %	30 Year Average (1991-2020)
APR-SEP	79355	80947	86	84083	94166
APR-JUL	67436	68629	84	70465	81933
APR-AUG	73955	75612	85	78367	89196
JAN-SEP	104550	106143	92	109279	115946
JAN-JUL	92632	93825	90	95661	103714
OCT-SEP	124436	126028	95	129165	132314

Experimental Water Supply

HEFS with 15 days EQPF **Ensemble:** 2026-06-10 **Issued:** 2026-06-10

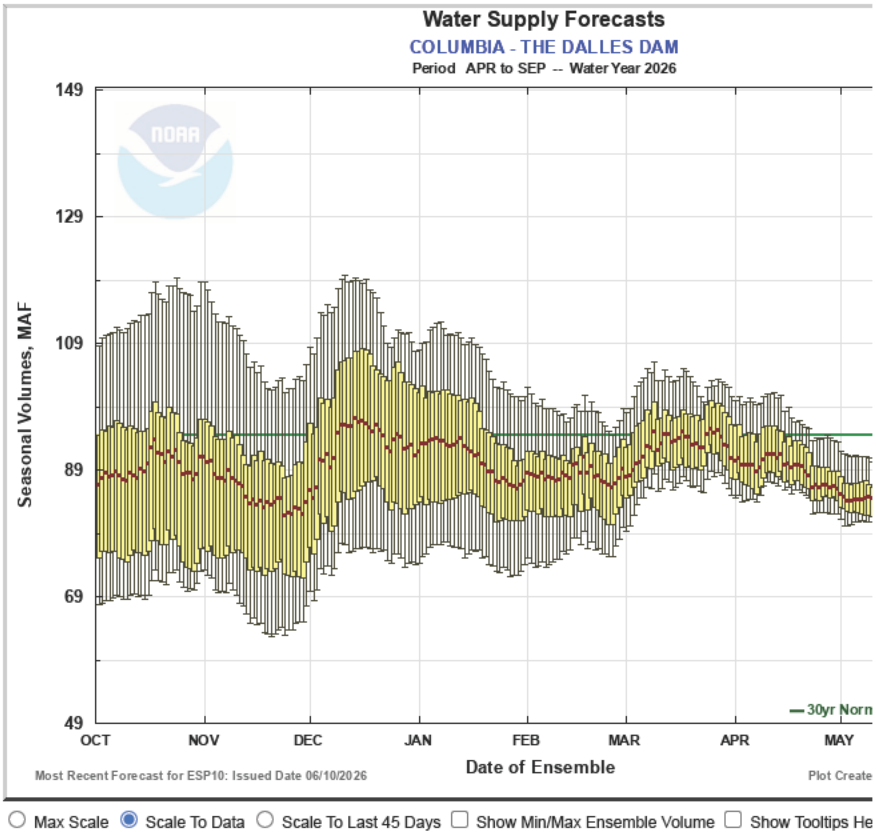
APR-SEP	79945	81708	87	84766	94166
APR-JUL	67913	69253	85	71672	81933
APR-AUG	74867	76193	85	79126	89196
JAN-SEP	105140	106904	92	109962	115946
JAN-JUL	93109	94448	91	96868	103714
OCT-SEP	125026	126789	96	129847	132314

Reference

ESP with 0 Days QPF **Ensemble:** 2026-06-10 **Issued:** 2026-06-10

APR-SEP	80797	83121	88	86635	94166
APR-JUL	68709	70270	86	73302	81933
APR-AUG	75722	77653	87	81044	89196
JAN-SEP	105992	108317	93	111830	115946
JAN-JUL	93904	95466	92	98498	103714
OCT-SEP	125878	128203	97	131716	132314

Move the mouse over he desired "Forecast Period" to display a graph.



Max Scale | Scale To Data | Scale To Last 45 Days | Show Min/Max Ensemble Volume | Show Tooltips He

Overlay: ESP10 | HEFS | ESP0

Data Files: CSV (ESP10 / APR-SEP)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

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

Exhibit 3-04:
NOAA June 10, 2026, Grand Coulee Dam Forecast

Northwest River Forecast Center
Water Supply Forecasts

Choose Date: 06/10/2026 Archive: Water Year

COLUMBIA - GRAND COULEE DAM (GCDW1)
Forecasts for Water Year 2026

Official Water Supply
ESP with 10 Days QPF **Ensemble:** 2026-06-10 **Issued:** 2026-06-10

Forecast Period	Forecasts Are in KAF 90 %	50 %	% Average	10 %	30 Year Average (1991-2020)
APR-SEP	57725	59339	97	62173	61483
APR-JUL	48829	49992	95	51817	52774
APR-AUG	53837	55526	95	57951	58186
JAN-SEP	70604	72217	102	75052	70457
JAN-JUL	61707	62870	102	64695	61749
OCT-SEP	81162	82776	105	85610	78842

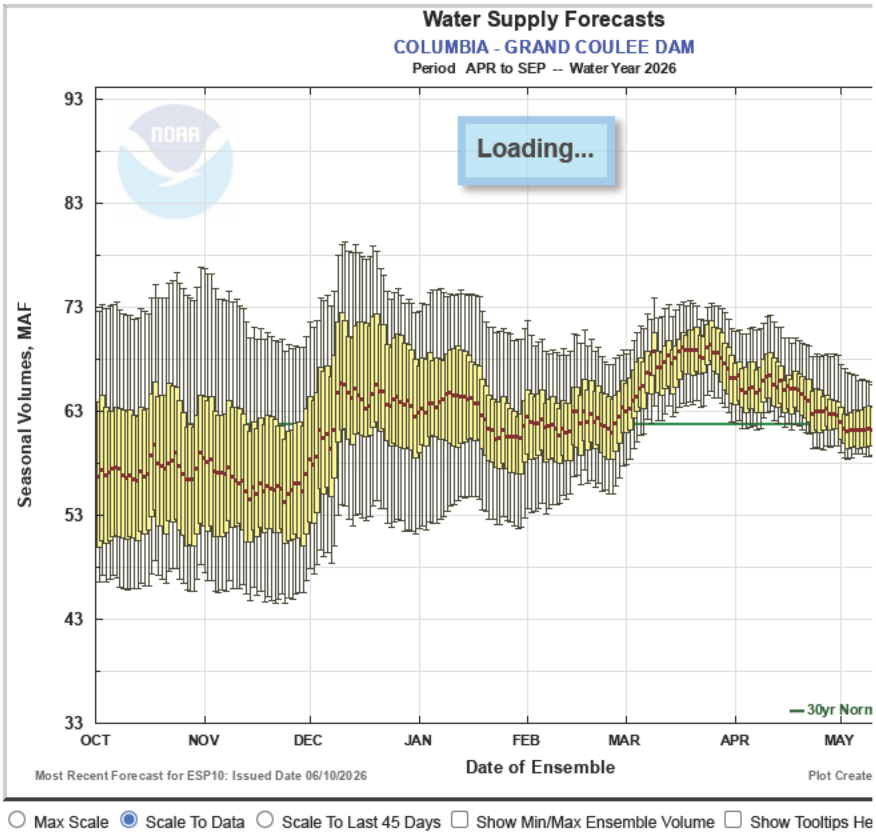
Experimental Water Supply
HEFS with 15 days EQPF **Ensemble:** 2026-06-10 **Issued:** 2026-06-10

APR-SEP	58195	59911	97	62733	61483
APR-JUL	49371	50643	96	52723	52774
APR-AUG	54934	56148	96	59038	58186
JAN-SEP	71073	72789	103	75612	70457
JAN-JUL	62250	63522	103	65602	61749
OCT-SEP	81632	83348	106	86170	78842

Reference
ESP with 0 Days QPF **Ensemble:** 2026-06-10 **Issued:** 2026-06-10

APR-SEP	59069	61132	99	63996	61483
APR-JUL	50016	51438	97	53973	52774
APR-AUG	55475	57407	99	60188	58186
JAN-SEP	71947	74010	105	76875	70457
JAN-JUL	62895	64316	104	66852	61749
OCT-SEP	82506	84569	107	87433	78842

Move the mouse over he desired "Forecast Period" to display a graph.



Max Scale | Scale To Data | Scale To Last 45 Days | Show Min/Max Ensemble Volume | Show Tooltips He

Overlay: ESP10 | HEFS | ESP0

Data Files: CSV (ESP10 / APR-SEP)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

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

Exhibit 3-05:
NERC 2026 Summer Reliability Assessment

2026 Summer Reliability Assessment

May 2026

RELIABILITY | RESILIENCE | SECURITY

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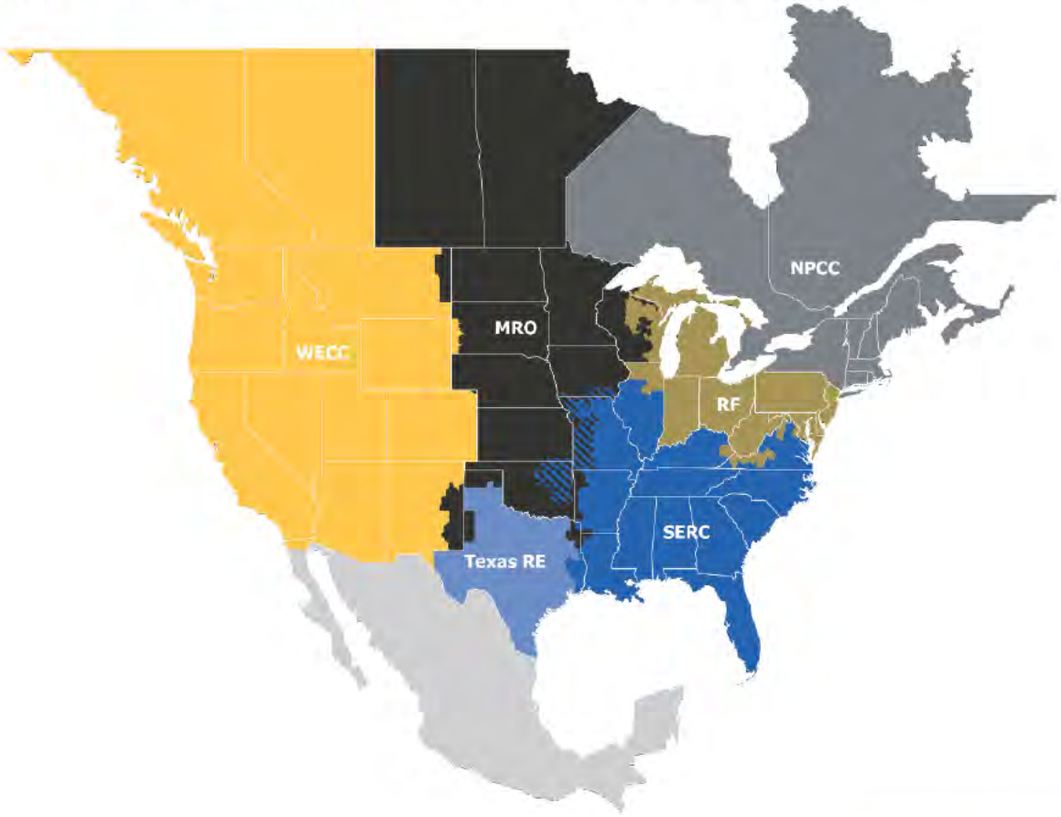
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Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY
POWERING TODAY. PROTECTING TOMORROW.

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



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

About This Assessment

NERC's *2026 Summer Reliability Assessment* (SRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the SRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and risk hours as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2025 Long-Term Reliability Assessment* (LTRA), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

The 2026 Summer risk profile is marked by rising demand, significant generation growth in many areas, the prospect of challenging hydrological conditions, and the unpredictability of large loads, from both a forecasting and operational perspective. Multiple assessment areas have revised load forecasts downward from mid-2025 projections to account for the observed rate of completion for large load interconnections and the slower-than-expected pace at which some of those loads are coming on-line. Still, aggregated peak demand across all assessment areas has increased by over 11 GW from Summer 2025 projections that were set earlier in 2025. That level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. As important as the demand growth itself is the timing of the demand. The early arrival of summer heat and high demand in March has highlighted the risks associated with potential overlaps between spring maintenance outages and high demand. The importance of shoulder season supply-demand analysis continues to grow. The BPS has added slightly more than 58 GW of new resources year on year heading into the coming summer. This large resource addition has partly contributed to the improved risk outlook for some areas. The resource additions continue to include a high proportion of variable energy resources, supporting the prioritization of low-wind event preparation and probabilistic analysis of available energy at peak and risk hours.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2026.

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

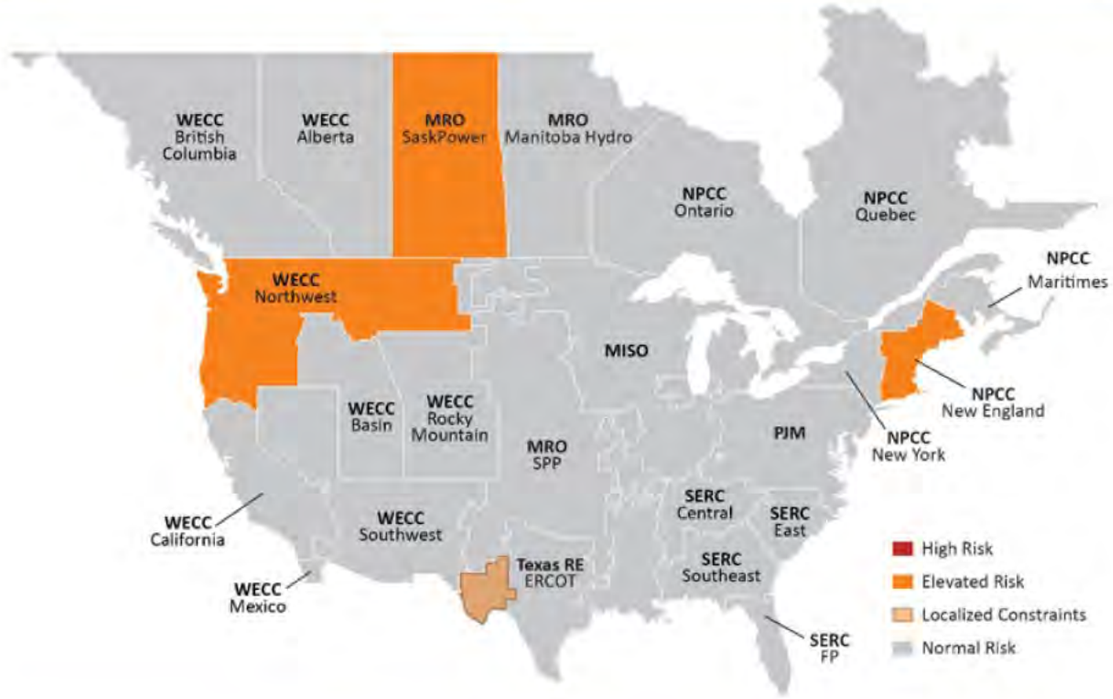
Resource Adequacy Assessment and Energy Risk Analysis

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

- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2026 Summer peak demand forecast for normal conditions with an Anticipated Reserve Margin of 14%, just above the Reference Margin Level of 13%. New England may rely on non-firm imports to cover shortfalls even as the region has lowered its projected net firm imports by 836 MW from the previous year's projections to just 409 MW for the coming summer season. The decline in firm transfers is the main driver of the 2.6% year-on-year drop in anticipated resources. Non-firm imports, however, received a boost in January with the addition of New England Clean Energy Connect (NECEC), a symmetric monopole +/- 320 HVdc line from the Appalaches substation in Québec to a new substation in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and can import up to 1,200 MW into New England. Total internal demand for the 50/50 peak summer demand forecast is 25,228 MW, up marginally from the demand projections in the *2025 SRA* of 25,202 MW. Expected increases in electrification are the biggest driver in the region's demand forecast as well as slight weather normalization changes. Other resource types have slightly increased from last year within the region. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2026 for the base case (50/50 normal demand). For the scenario with the highest peak load and reduced resources, the results were a cumulative loss of load expectation (LOLE) of <0.35 days/period, loss of load hours (LOLH) of <1.2 hours and expected unserved energy (EUE) of 628 MWh/period.
- **MRO-SaskPower:** SaskPower was at elevated risk in the *2025 SRA*, and resource adequacy metrics have declined slightly year on year for the upcoming summer period. Reserves have tightened from 34% to 29% due to a ~1.9% demand growth and no substantial change in resources. While SaskPower does not anticipate capacity constraints or reliability issues under normal conditions, extreme summer conditions may cause SaskPower to require maintenance rescheduling, short-term power transfers from neighboring utilities, and/or available demand-response programs. SaskPower's probabilistic in-house model showed an LOLH for an elevated risk scenario for the 2026 Summer season to be 0.09 hours; the month with the highest LOLH is September (0.05 hours).
- **WECC-Northwest:** The coming summer brings challenging hydrological conditions for regions in which hydropower makes up half or more of the supply fleet. Almost the entire Western Interconnection is in the grips of a persistent drought or in an area where drought development has a greater likelihood through the end of July. In Washington, for example, the snow water equivalent was at 52% of normal levels as of April 1 this year,[2] when snowpack typically reaches its peak. While the total water year supply is forecast to be nearly average in the Columbia River Basin, snowpack peaked at low elevation and melted early in the year. This has implications for the expected resources available to the Northwest, the generation mix for which is 55% hydropower. The region is contending with a nearly 5% increase in net internal demand from the *2025 SRA* and a nearly 2% drop in existing resources as well as a roughly 43% drop in expected Tier 1 resources. Though higher modeled net transfers are projected to contribute double what they were projected to last year (albeit with the increase largely attributable to a modeling change that accounts for economic transfers), this was not enough to prevent the drop in the Anticipated Reserve Margin from 32% last year to 27% this year. For this summer's assessment, WECC's study for the Northwest region resulted in small amounts of EUE, increasing from zero in the previous probabilistic assessment. The study also indicated an LOLH of >0.1 hours/period. The hour of greatest risk occurs around 6:00 p.m. in early September.
- **Texas RE:** The Texas Interconnection is widely at a normal risk level for Summer 2026 due to a 12% jump in anticipated resources for the summer period and a 4.5% decline in projected net internal demand. The lower demand forecast is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads. The results of ERCOT's Probabilistic Reserve Risk Model (PRRM) simulation indicate a low risk of declaring an energy emergency alert (EEA) during the risk hour (9:00 p.m. local time). However, the PRRM does not capture the pre-contingency load shedding risk in the Far West region of ERCOT's footprint resulting from rapid growth in both load and resources in this zone. Operational

[2] WSOR-WA

challenges could arise in Far West Texas during periods of high demand combined with low wind output and absence of solar generation. Under these conditions, transmission constraints in the Far West Texas zone may become binding. Price-responsive demand is expected to help reduce transmission congestion and maintain balance with supply during tight conditions. In addition, ERCOT and transmission service providers have developed mitigation measures to address these constraints by incorporating dynamic line ratings that account for solar irradiance along with ambient temperatures. Operating procedures that include involuntary load curtailment are in place to maintain system operating limits when needed. In September 2025, two new thermal cascading Interconnection reliability operating limits (IROL) became effective in the Far West region of ERCOT's footprint.



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

Figure 1: Summer Reliability Risk Area Summary

Other Key Reliability Highlights

- **Weather services are expecting an El Niño weather pattern to influence the weather outlook for the 2026 Summer period.**[3] El Niño weather patterns can suppress Atlantic hurricanes, which are a major reliability consideration for the Gulf Coast and Southeast United States. Temperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South and West and cooler-than-normal temperatures in the upper Midwest and parts of the Northeast (see Figure 2). Wetter-than-normal conditions could alleviate drought severity in the Gulf Coast, but the U.S. Northwest is still expected to see drier-than-normal conditions,[4] starting with sub-average snowpack[5] heading into spring that can impact the availability of hydropower units in a region that relies heavily on hydro-fueled electricity generation. In Canada, higher-than-normal temperatures are expected across the country, with the greatest likelihood residing in northeast and southwest Canada. Snowpack in Canada is generally in average conditions. British Columbia has experienced below-average snowpack in the southwest part of the province and above-average snowpack in the Columbia and Peace regions. The Review of 2025 Capacity and Energy Performance section describes actual demand and resource levels in comparison with NERC's *2025 SRA* and summarizes 2025 resource adequacy events.

- **A large influx of BPS resources over the past year has outpaced demand and is boosting reserves.** BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural-gas-fired generators. Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.

- **Strong load growth continues in nearly all assessment areas.** Load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Aggregated peak demand across all assessment areas has increased by over 11 GW since 2025. The level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. The largest increases are in parts of the U.S. West. WECC-Southwest saw the largest year-on-year increase in net internal demand at +9.5%, followed by WECC-Northwest with +4.6% and WECC-Basin with 3.8%. Overall, 19 out 23 assessment areas saw demand increases from the *2025 SRA* projections.

- **Large computational and other large loads pose operational challenges for the upcoming summer.** Recent events of unexpected disconnections underscore the need for operational readiness for the upcoming summer. For example, the Eastern and ERCOT Interconnections have observed load-reduction events with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction.[6] The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation, which caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying sizes reducing consumption during an extended low-voltage period in West Texas due to a protection system misoperation. These load-reduction events highlight some of the potential risks posed by large loads utilizing the BPS and why NERC is closely examining this issue. NERC issued a Level 3 essential actions alert related to large loads[7] as well as a reliability guideline regarding risk mitigation for emerging large loads.[8]

- **Battery resource additions help maintain stable frequency on the grid.** Since last summer, over 16 GW of nameplate battery storage capacity has been added to the grid. Texas and the Western Interconnection continue to have the strongest growth in these resources. The *2025 State of Reliability* report noted an upward trend in frequency response capability that can be attributed to the addition of battery storage resources.[9] Charged battery storage resources can respond quickly to the abrupt decline in system frequency that occurs during disturbances and sudden imbalances, helping to maintain the nominal 60 Hz system frequency and prevent equipment damage and system instability. NERC's *2026 State of Reliability* report, to be published in June, will report on this continuing trend of improved grid frequency response.

[3] Climate Prediction Center: ENSO Diagnostic Discussion
[4] Climate Prediction Center: Seasonal Drought Outlook
[5] WSOR-WA
[6] *Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions*, NERC, January 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf
[7] NERC Level 3 Alert: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control
[8] Risk Mitigation for Emerging Large Loads
[9] NERC State of Reliability reports

- **The overlap of early summer heat and spring maintenance outages can lower operating reserves in the shoulder season and early summer.** March 2026 was the warmest March in the 132 years of recordkeeping in the contiguous United States.[10] The average temperature across the country was 9.4°F above the 20th-century average. Raising the average were at least 10 states in the U.S. West that had their warmest March on record. The widespread heat-dome bled across the border and infused unseasonably warm temperatures into British Columbia as well, with at least five communities in the southern part of the province recording their warmest overnight low temperatures ever observed for the month of March.[11] Some assessment areas in the West have reported that extended lead times for hydro unit overhauls and the limited availability of engineering, procurement, and construction contractors are contributing to longer outage durations that complicate maintenance planning. Longer-than anticipated maintenance periods, in turn, can lead to higher-than-expected calls on electricity imports from neighboring regions. In other areas, there are older sites that may require extensive overhauls, such as generator rewinds that can keep resources out of service for extended periods of time, potentially longer than planned, as discovery work manifests into additional maintenance.
- **Impacts of wind drought (i.e., low wind periods) pose a risk to reliability.** Areas of the North American electric grid continue to experience periods of wind drought or steep wind down-ramping, and installed wind capacity across the BPS is up by 3% year on year. It is critical that areas experiencing these events continue to maintain operational awareness, including accurate forecasts and appropriate operating procedures to mitigate these periods. Additionally, the impact of wind ramp events—particularly down ramp—must be anticipated and planned for such that appropriate resources are ready to replace the energy lost during these conditions. It is not uncommon for areas to experience several thousands of megawatts of wind energy coming off-line during these events. For example, in January 2025, MISO experienced a wind reduction event of 1,600 MW per hour, which also coincided with a solar ramping down and evening load ramp up.[12]

[10] Assessing the U.S. Temperature and Precipitation Analysis in March 2026 | News | National Centers for Environmental Information (NCEI)
[11] Blazing hot: 1,000+ records fall in brutal March heat wave - The Weather Network
[12] *Incident Review: Preparing the Grid for Wind Energy Droughts and Down-Ramps*, https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_low_wind_event.pdf

Recommendations

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

- Reliability Coordinators (RC), Balancing Authorities (BA), and Transmission Operators (TOP) in the elevated-risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of above-normal demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. Past system performance reviews noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[13]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- RCs, TOPs, and BAs should review outage coordination processes and policies and consider if adjustments are needed to account for potential above-normal temperatures to extend beyond the traditional summer season. Those same entities should also be prepared to adjust operating plans in early summer for delayed return-to-service of BPS generation and transmission elements.
- BAs should consider the following steps to reduce risks to system balance from conditions that could affect resources or demand for the upcoming summer:
  - **Wind energy:** In areas with ample wind resources, employ proactive operating plans for low-wind events and wind down-ramping events when weather conditions are developing or are uncertain.
  - **Hydro availability and output:** In areas with a predominance of hydro generation in the supply stack, consider in operating plans the potential for low water conditions to affect hydro generation. Coordinate a sufficient supply of alternative resource types and ready necessary demand-side management mechanisms if needed.
  - **Large computational load disconnects:** Be aware of the potential for load reductions from large computational loads in response to system conditions and include conservative practices in operating plans. Refer to NERC's incident reviews for details of recent events involving voltage-sensitive data centers and cryptocurrency mining facilities.[14]

[13] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.

[14] See Incident Review section of NERC Event Analysis page.

Risk Highlights

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. March of this year brought record heat for the month and exacerbated concerns over persisting or worsening drought, concerns that gained even more traction following an underwhelming snowpack peak in the Pacific Northwest in April. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

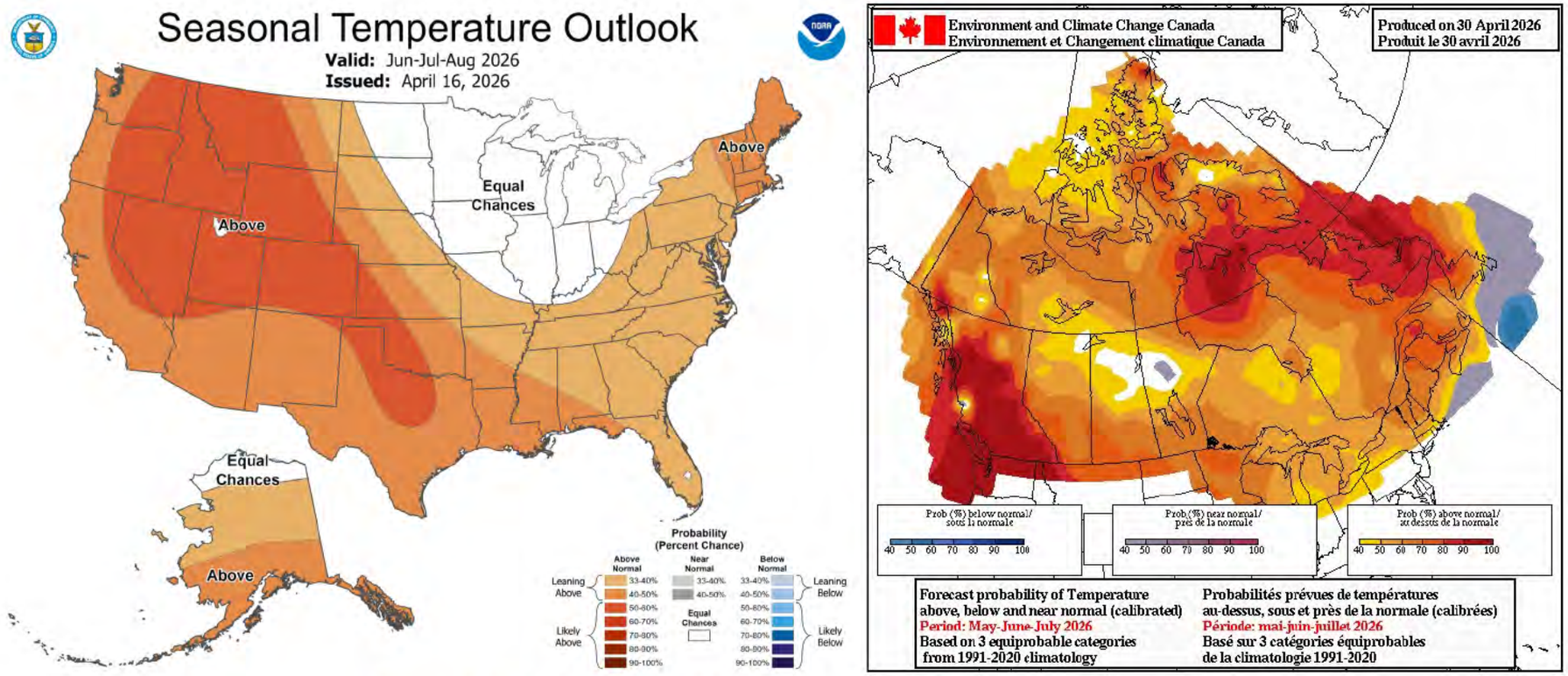


Figure 2: United States and Canada Summer Temperature Outlook[15]

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

Demand and Resource Trends

Strong load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Resource additions over the past year have outpaced demand growth, contributing to higher reserves.

Summer Electricity Demand Continues to Rise

Aggregated peak demand across all assessment areas has increased by over 11 GW since 2025, comparing forecasted net internal demand (NID). This measure of peak demand is inclusive of the benefits from demand response, which offset total internal demand (TID) (see Figure 3). NID continues to accelerate. The year-on-year increase in peak demand for Summer 2025 was 10 GW—more than double the increase in peak demand from 2023 to 2024.

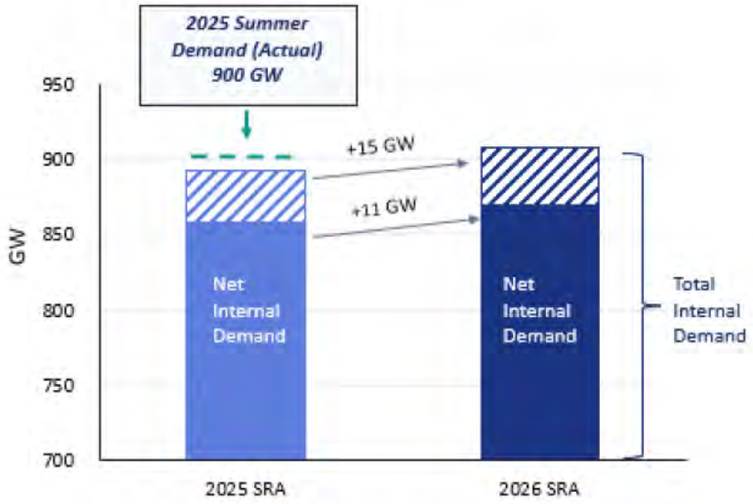


Figure 3: BPS Total and Net Internal Demand
Aggregated Peak Demand from All Assessment Areas

Nearly all assessment areas are experiencing demand growth. Peak demand forecasts have risen since 2025 in 19 of the 23 assessment areas. The largest increases are in parts of the U.S. West. In Canada, all provinces are forecasted to have increases of 2% or more except for Québec, which is forecasting a 1% decline in peak demand. Texas RE-ERCOT is a notable exception to the growth trend this summer. TID in ERCOT declined by 1.9 GW (2.3%), largely driven by updated forecasting that accounts for observed behavior of large computational loads at peak demand. NID, which includes demand response, is 3.7 GW lower (4.6%) compared to last summer because more data centers can be curtailed by grid operators when needed to prevent grid emergencies. A summary of assessment area demand changes is provided in the Net Internal Demand section.

More Resources Available for Summer

BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural gas-fired generators (see Figure 4). Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). Battery additions account for 14.7 GW in increased on-peak capacity. These resources also help balance variability in solar PV and wind resources, as well as demand fluctuations. Other capacity changes since 2025 amounting to 19 GW are attributed to resource additions of other types as well as changes to generator availability (e.g., completion of extended nuclear generator outages, changes to maintenance plans). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.

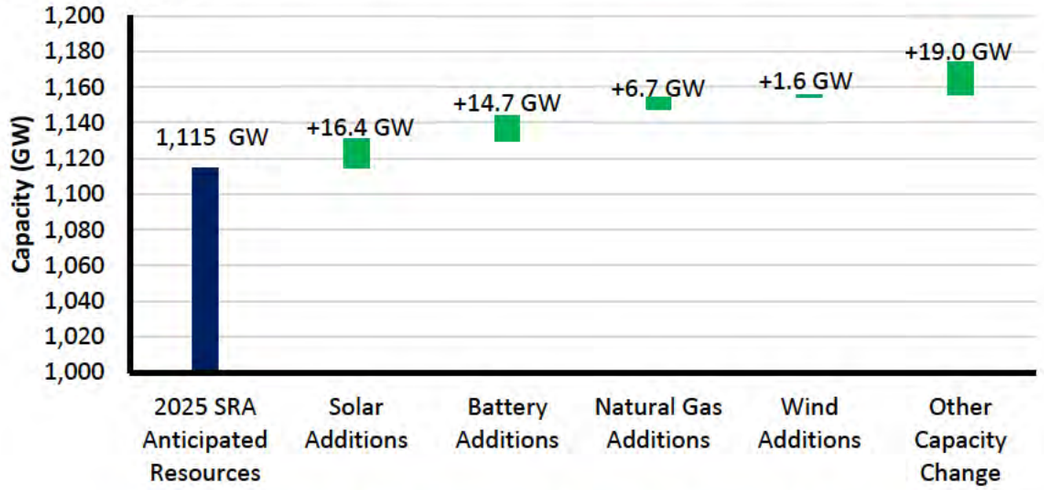


Figure 4: Summer BPS Resource Capacity Change Since 2025

Generators Extended by Federal Power Act Emergency Authority

Starting in 2025, the Department of Energy (DOE) issued emergency orders, pursuant to section 202(c) of the Federal Power Act, requiring that six different power plants maintain operational availability. Thermal generators with diverse fuel sources can be an important electricity resource, especially during winter when solar PV and battery resources are less capable compared to summer months. The DOE has since renewed those emergency orders, extending availability requirements into late May and early June (see Table 1). These plants and units were not incorporated into the anticipated resources of their corresponding assessment areas for Summer 2026 but may be called upon within the orders' time frames.

Table 1: Power Plants Impacted by Department of Energy 202(c) Orders in 2025 and 2026

Assessment Area	Plant Name	Nameplate Capacity (MW)	Summer Capacity (MW)	DOE 202(c) Order Expiration
MISO	J.H. Campbell	782	760	5/18/2026
MISO	F.B. Culley Generating Station	104	90	6/21/2026
MISO	Schahfer Generating Station	847	722	6/21/2026
PJM	Eddystone Generating Station	782	760	5/24/2026
WECC-NW	Centralia Generating Station	730	670	6/14/2026
WECC-RM	Craig Station	446	427	6/28/2026

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 2.

Table 2: Seasonal Risk Assessment Summary

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

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

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 3.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	31.1%	21.6%	3.8%
MRO-Manitoba	13.2%	9.5%	4.3%
MRO-SaskPower	29.2%	23.2%	7.3%
MRO-SPP	26.8%	21.4%	3.8%
NPCC-Maritimes	83.8%	73.4%	53.3%
NPCC-New England	14.0%	4.0%	-0.9%
NPCC-New York	34.2%	15.0%	7.5%
NPCC-Ontario	32.4%	32.4%	12.3%
NPCC-Québec	34.5%	16.4%	7.3%
PJM	26.2%	16.1%	3.8%
SERC-C	18.9%	13.9%	5.6%
SERC-E	26.3%	17.4%	10.3%
SERC-FP	25.8%	20.7%	13.6%
SERC-SE	36.9%	33.1%	24.7%
TRE-ERCOT	67.9%	60.2%	20.4%
WECC-AB	32.3%	28.2%	9.1%
WECC-Basin	37.6%	34.9%	11.5%
WECC-BC	40.5%	40.0%	9.6%
WECC-Cal	55.6%	54.3%	17.0%
WECC-Mex	32.5%	25.5%	11.0%
WECC-NW	26.9%	25.2%	8.8%
WECC-RM	51.9%	49.2%	21.5%
WECC-SW	48.1%	44.7%	25.2%

Seasonal risk scenarios for each assessment area are presented in the Regional Assessments Dashboards section. The on-peak reserve margin and seasonal risk scenario charts in each

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

The seasonal risk scenario charts can be expressed in terms of reserve margins: In Table 3, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in orange are the areas identified as having resource adequacy or energy risks for the summer in the Key Findings section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be on maintenance or forced outage during peak demand conditions. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's summer risk scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in Table 4. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2026. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

EEA Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 4: Probability-Based Risk Assessment

Assessment Area	Type of Assessment	Results and Insight from Assessment
MISO	Planning Year 2026–2027 LOLE Study Report	MISO's values for LOLH and EUE are taken from the noted assessment report, where the annual LOLE was set at 1 day in 10 years or 0.1 LOLE but equated to 0.076 LOLE for the summer. For Summer 2026, LOLH is 0.235 hrs/year and EUE is 983.8 MWH/year for the Reference Margin Level. Expectations for load loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	2024 and 2025 NERC Probabilistic Assessment (ProbA)	Manitoba Hydro's probability-based resource adequacy risk assessments for the summer season display risk when hydro flow conditions are low and load is higher than expected. Based on the analysis that was conducted for the 2024 and 2025 ProbA, this risk was considered low as normalized EUE was less than 2 parts per million and LOLH was less than 0.2 hrs/year.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2026	SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). LOLH equated to 0.09 hrs/season, and the month of highest risk has shifted from June to September, when the system experiences the largest uncertainties in load and generator availability forecasts. September risk makes up over 50% of summer season risk within this assessment area. SaskPower indicated that in extreme conditions, it may have to use short-term power transfers from neighboring utilities, maintenance rescheduling, and/or demand-response programs to prevent energy shortfall.
MRO-SPP	SPP East Assessment Area and 2024 NERC Probabilistic Assessment (ProbA)	Based on SPP East's probabilistic assessment and the 2024 NERC ProbA, risk observed in summer 2026 was minimal. Risk hours that materialized during simulations occurred during late afternoon and early evening periods and were driven by high demand and low wind conditions.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes Area is not expected to require use of its established operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. The Maritimes Area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain a balance over the May–September summer period for all the scenarios modeled.
NPCC-New England		The preliminary results[16] of NPCC's probabilistic assessment indicate that use of New England's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages. Preliminary cumulative LOLE (days/season), LOLH (hours/season), and EUE (MWh/season) risks were reported as negligible over the summer May to September period for the expected load with expected resources scenario. Under an extreme scenario, the estimated cumulative LOLE risk is 0.343 days/period, with associated LOLH of1.178 hours/period and EUE of 628 MWh/period with the highest risk occurring in June, with some in July and August.

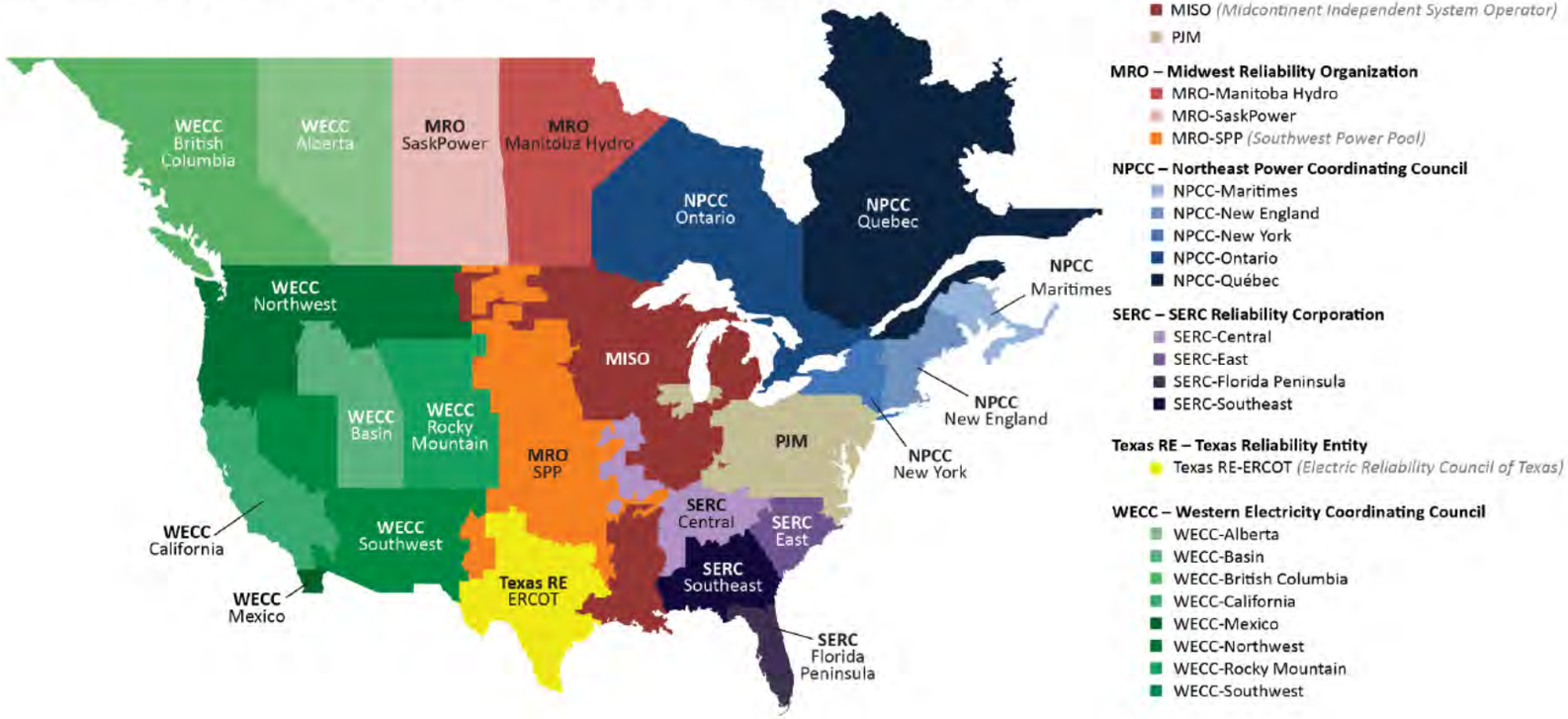
[16] Based on preliminary runs from March 31, 2026

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-New York		The preliminary results of NPCC's probabilistic assessment indicate that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026 with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE, which is below elevated risk criteria under the scenario of highest peak load and reduced resource conditions; the estimated cumulative risk reached 0.655 days of LOLE, 2.004 hours of LOLH, and 1,262 MWh of EUE, with the greatest risks occurring in July and August.
NPCC-Ontario		The preliminary results of NPCC's probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.
NPCC-Québec		The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of its operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking. The Québec area expects to be able to help other areas if needed.
PJM	2023 PJM Reserve Requirement Study (RRS)	The RRS analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer. PJM is forecasting 26% installed reserves (including expected committed demand response), which is above the reserve requirement margin of 18.6% necessary to meet the 1-day-in-10-years LOLE criterion.
SERC	Probabilistic resource adequacy assessment for the 2026 Summer season	SERC performed a probabilistic resource adequacy assessment for the summer season (June–September) using the PowerGEM SERVM model. The analysis is based on an 8,760 hourly model with 5,375 Monte Carlo simulations per hour and incorporates data across 43 historical weather years (1980–2022), load forecast uncertainty, generator forced outages, power transfer between SERC assessment areas, and variable energy resource performance.
SERC-Central		Results from the summer 2026 probabilistic risk assessment indicate that resources will be sufficient to meet projected demand and do not exhibit any EUE or LOLH.
SERC-East		Simulations performed show that small amounts of EUE materialized in a single summer evening hour under a high-stress scenario involving elevated load, reduced solar output during the evening ramp, and coincident generator outages. The magnitude and frequency of the event are low and do not indicate a broader resource adequacy concern.
SERC-Florida Peninsula		No EUE or LOLH materialized within SERC-Florida Peninsula across all simulations, which resulted in an implied LOLE of approximately zero. These results indicate that available resources are sufficient to meet projected demand under modeled conditions.
SERC-Southeast		The probabilistic assessment did not identify any loss of load events for SERC-Southeast during the Summer 2026 season. EUE and LOLH were both zero across all simulation hours.
Texas RE-ERCOT	ERCOT probabilistic assessment using the PRRM	The simulation indicates low risk of having to declare an EEA for hour 21, the highest risk hour for the peak load day in August (which is also the expected summer peak load day) with a probability of declaring an EEA of 0.43%. This is categorized by ERCOT as "low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2025 SRA*, ERCOT reported EEA declaration probability for hour ending 21 of 3.1%. The large decrease in EEA probabilities is due to the addition of 8,780 MW of BESS capacity in 2025 and 2,677 MW more as of March 2026.

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC	Probabilistic resource adequacy assessment for the 2026 Summer season	For the 2026 SRA, WECC, for the first time, performed a probabilistic resource adequacy assessment using the PowerGEM SERVM model based on an 8,760 hourly model that incorporates data across 43 historical weather years, load forecast uncertainty, generator forced outages, power transfers, and variable energy resources shapes. With this shift, WECC opted to default to the NERC defined Reference Margin Level and change its reporting to reflect the different data construct and reporting of results.
WECC-AB		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC–Basin		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-BC		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-CA		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-Mex		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-RM		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-NW		WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
WECC-SW		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.

Regional Assessments Dashboards

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





MISO

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

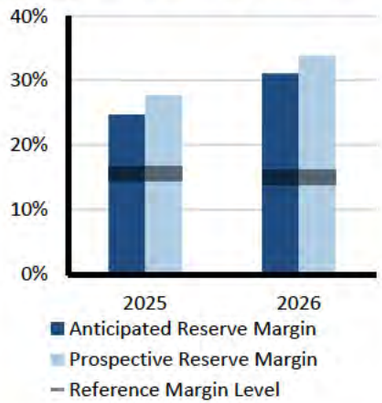
Highlights

- Although MISO's peak load has increased by 2.5 GW from the *2025 SRA*, MISO is not anticipating operational or reliability issues for the 2026 Summer season. Load growth is driven by increased projections of data center load and is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts.
- MISO's capacity resources have improved since Summer 2025, and new additions are made up of predominantly solar resource installations, along with smaller amounts of natural gas, wind, and battery storage resources. Solar resources are helping the system serve peak load but are shifting risk hours to later in the day where intermittent resource capabilities are low and temperatures are above expected conditions.
- MISO benefits from transmission connections with neighbors to meet extreme weather conditions, and reliance may increase when extreme conditions arise.

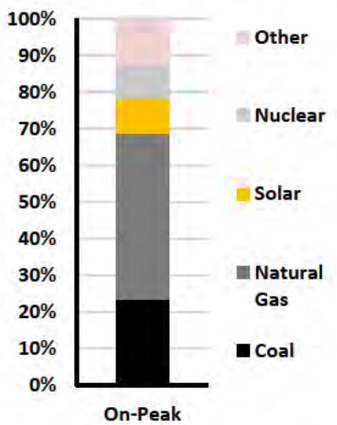
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios. Above-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access demand-response resources when operating reserve shortfalls are projected.

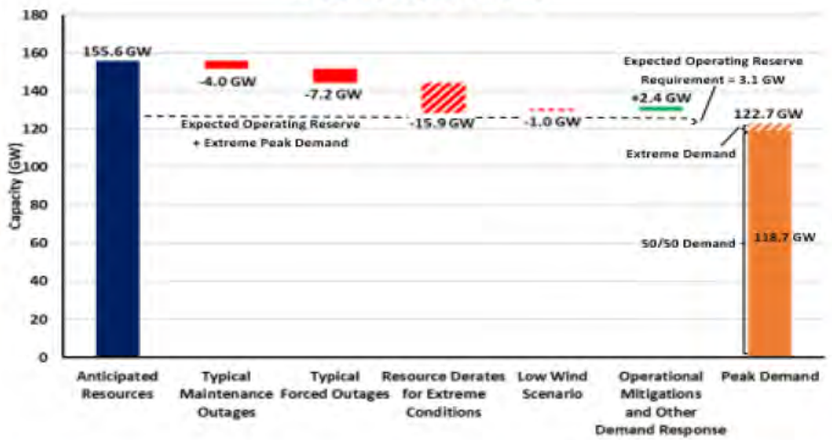
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand forecast (50/50) plus transmission losses.

Maintenance Outages: Rolling three-year average of maintenance outages that occurred during the summer (June-September) peak hour.

Forced Outages: Rolling three-year average of forced outages that occurred during the summer (June–September) peak hour.

Extreme Derates: Rolling three-year average of maintenance and planned outages that occurred across thermal resources during the summer (June-September) peak hour, plus a reduction in solar resource performance during the risk hour.

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



MRO-Manitoba Hydro

Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

Highlights

- Manitoba Hydro is not anticipating any operational challenges or emerging reliability issues in its assessment area for Summer 2026.
- Manitoba Hydro's demand increase of 2.5% is driven primarily by population and economic growth, including electrification of a large industrial customer to reduce carbon emissions. Currently, new cryptocurrency operations cannot connect in Manitoba due to a moratorium.
- The 2024 ProbA for the 2026 load year shows an EUE of 4 MWh and an LOLH of 0.05 hours.
- Manitoba Hydro's reservoir storage conditions are below average, but winter snowfall has been above average, which should favorably impact spring runoff. The Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations, even if extreme drought develops through 2026–2027.
- Manitoba Hydro continues to monitor summer resource adequacy in the MISO area but does not believe that there are significant seasonal reliability issues in MISO or in other neighboring assessment areas that have potential to impact Manitoba Hydro operations for Summer 2026.
- The Anticipated Reserve Margin for Summer 2026 exceeds the 12% Reference Margin Level.

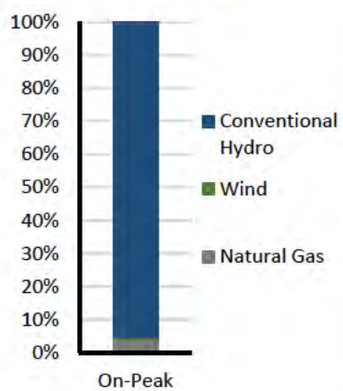
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

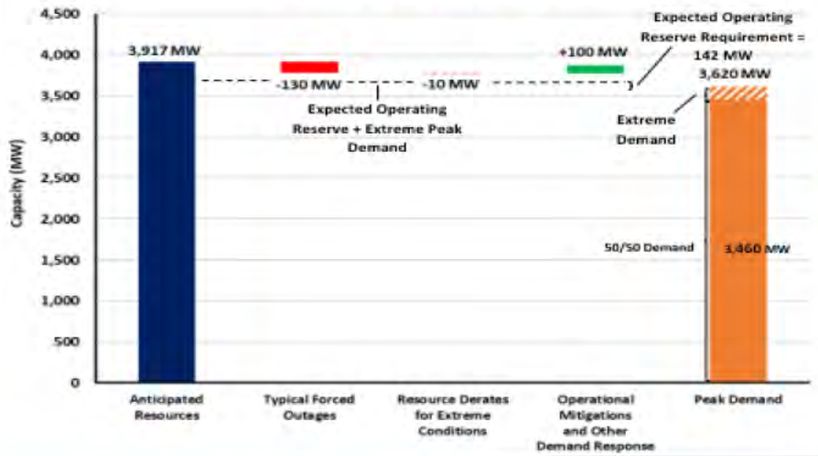
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: 50/50 Demand with allowance for extreme demand based on a 90th percentile extreme weather scenario of 36.0 C (96.8 F).

Forced Outages: Typical forced outages.

Extreme Derates: Summer wind capacity accreditation of 18.2% of nameplate rating based on MISO seasonal analysis. No further wind output derates based on experience; wind farms constitute less than 1% of Manitoba Hydro's available capacity.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; assume 100 MW of non-firm imports available.



MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- There is a 1.9% increase in TID from the *2025 SRA* projection. This growth is mainly driven by population growth in the province, expansion projects, reduced self-generation in the industrial sector, and increased electrification.
- SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). According to probabilistic in-house model, the LOLH for an elevated risk scenario for the 2026 Summer season is 0.09 hours, which is nearly in line with the 0.1 LOLH risk criteria NERC sets for the elevated-risk level. The month with the highest LOLH is September (0.05 hours).
- Based on the planned maintenances, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during Summer 2026. Under extreme conditions, however, SaskPower may have to use short-term power transfers from neighboring utilities, maintenance outage deferrals, and/or demand-response programs to maintain sufficient supplies.

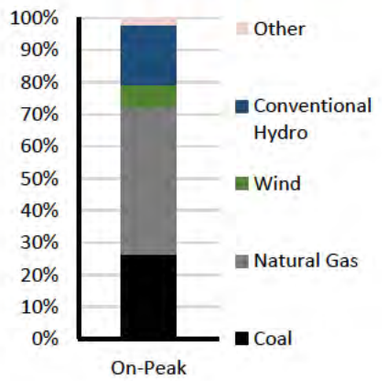
On-Peak Reserve Margin



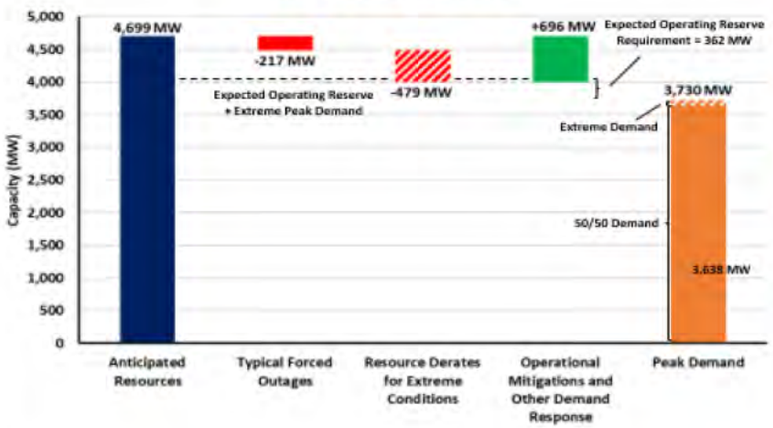
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. During extreme summer conditions causing above-normal demand or generator outages, SaskPower can experience operating reserve shortfalls that it would mitigate using rescheduled planned maintenance, short-term power transfers from neighboring utilities, and/or available demand-response programs.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads.

Forced Outages: Based on historic generation stats and SaskPower's forced outage rate models.

Extreme Derates: Based on the wind turbines datasheet and the percentage of the total available wind that will be cut off when the temperature is extremely high (40 degrees and higher).

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7 days' notice. In addition, 176 MWs of demand response can be called upon during operating emergencies.



MRO-SPP

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

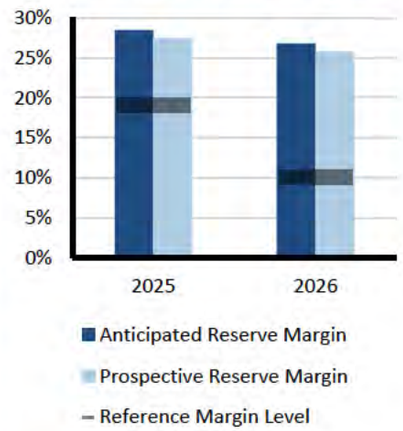
Highlights

- At this time, SPP does not anticipate any operational challenges that would result in reliability risk under normal conditions.
- SPP has operational procedures in place to manage generation outages taken over the summer to ensure appropriate generation is in place for high load. These procedures utilize probabilistic forecasts on factors such as load, generation, and outages to prepare for upcoming peak conditions.
- With heavy reliance on wind generation, SPP's greatest summer risk periods are when wind availability is low. If these low wind periods correspond to peak load conditions, then the combination presents extra risk for the area.
- SPP is projecting a 1.5% increase in forecasted 2026 Summer peak load vs. 2025 Summer peak actuals. Solar PV and energy storage continue to grow rapidly.

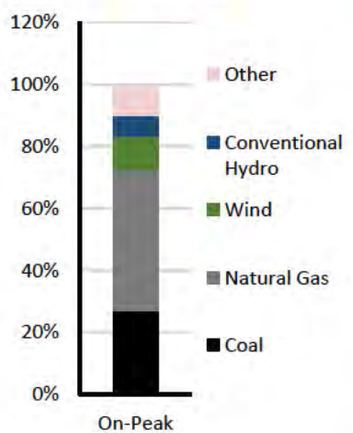
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. A combination of higher-than-average demand or lower-than-expected wind generation could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems), including resource advisories and EEAs, where appropriate.

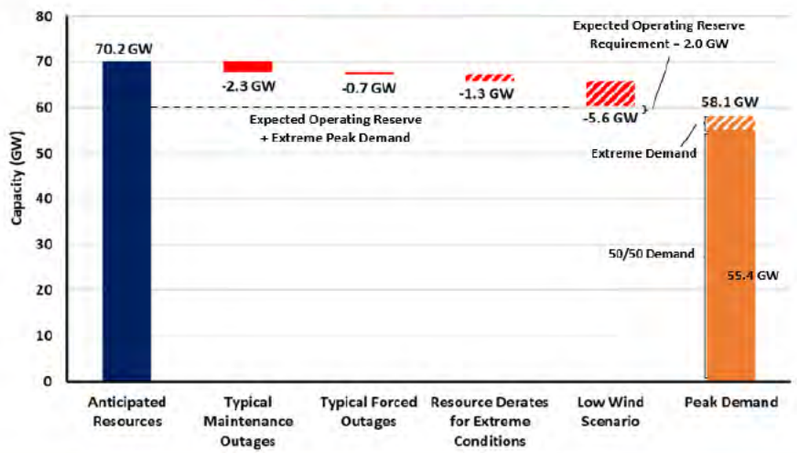
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 4.9% increase from net internal demand.

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

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

Low Wind Scenario: Derates reflecting an average low-wind day in the summer.



NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the BA for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the BA for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

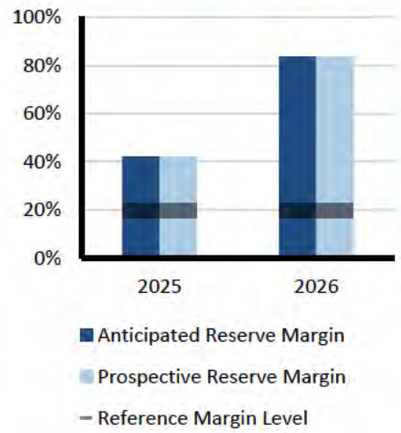
Highlights

- There are no anticipated issues for the Maritimes in the upcoming summer assessment period with sufficient firm capacity to meet the forecast peak demand.
- The Maritimes has not identified any operational issues that are expected to impact system reliability. Emergency operations and planning procedures are in place to mitigate operational events.
- Maritimes summer on-peak reserve margin is largely driven by resource maintenance outages. As a result of fewer planned outages (~1,000 MW) at peak, the 2026 on-peak reserve margin doubled from the 2025 SRA (84% compared to 42%).
- The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes area is not expected use their operating procedures during the Summer of 2026 to maintain sufficient supply. The Maritimes area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain an energy balance over the May–September summer period for all the scenarios.
- Although margins can go negative in May under the high load (above 90:10) scenario, there are opportunities to purchase non-firm energy through the interconnections with neighboring control areas as this scenario does not coincide with either the Maritimes or the NPCC summer peaks.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to enable sustained operation in the event of natural gas supply interruptions.

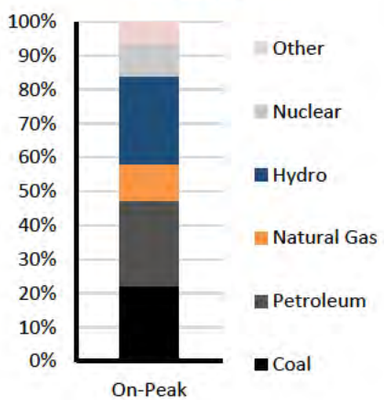
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

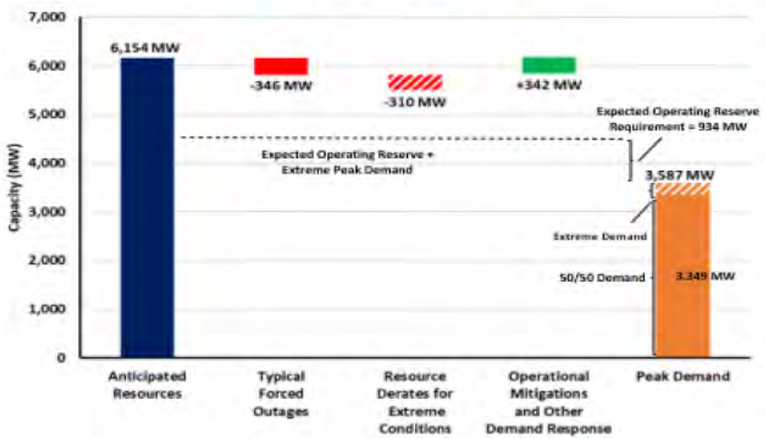
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Based on historic operating experience.

Extreme Derates: A low-likelihood scenario comprising a 100% derate of solar and storage, a 50% derate of wind (calm weather), and a 50% derate to natural gas (fuel supply issue).

Operational Mitigations: Changes to system operating conditions in the Maritimes area (i.e., transmission and/or generator outages) will be managed using short-term operating procedures (STOP), which would outline any special operating conditions for the operators.



NPCC-New England

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

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

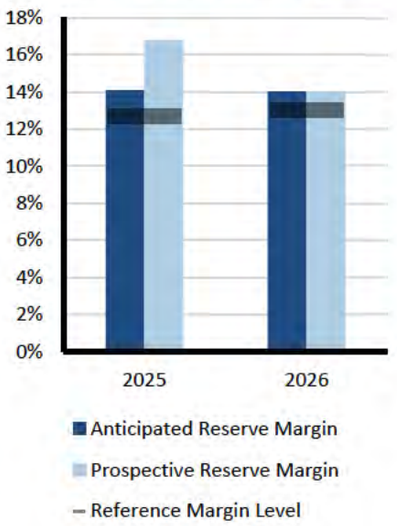
Highlights

- The New England area Anticipated Reserve Margin of 14% marginally exceeds the Reference Margin Level of 13%, avoiding a shortfall between anticipated resources and the reference level for reserves. There is, however, a 41 MW shortfall if resource additions are not included.
- ISO-NE assumes a net interchange of 409 MW, which is capacity-backed; however, ISO-NE typically imports around 3,000 MW during summer peak load conditions.
- ISO-NE does not anticipate any operational challenges or reliability issues for the upcoming 2026 Summer assessment period and forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand and operating reserves.
- Since January 2026, New England has added NECEC, a symmetric monopole +/- 320kV HVdc line from the 735 kV Appalaches substation in Québec to a new 345 kV substation, Merrill Road in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and is capable of importing up to 1,200 MW into New England, but only on a non-firm basis for the coming summer.
- A probabilistic assessment was conducted for New England, modeling both NPCC and its neighboring regions. The analysis simulated a base case (50/50 normal demand) alongside a highest peak load scenario, which has a 7% probability of occurrence. The preliminary results of the probabilistic assessment indicate that use of New England's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. Under the scenario of highest peak load levels and reduced resource conditions, the estimated cumulative risk reached 0.343 days of LOLE, 1.178 hours of LOLH, and 628 MWh of EUE, with the greatest risks occurring in June and July. The final NPCC 2026 Summer Reliability Assessment will be approved in May 2026.

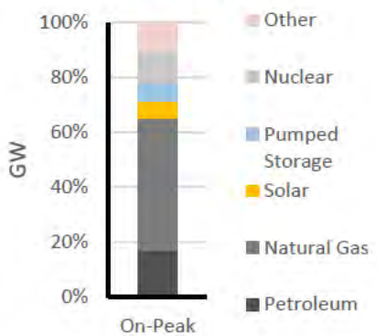
Risk Scenario Summary

The New England area expects to have sufficient resources to meet the 2026 summer peak demand forecast through the use of its established operating procedures and significant imports over its many ties to its neighbors that have historically been able to provide up to 3,000 MW during summer peak load conditions.

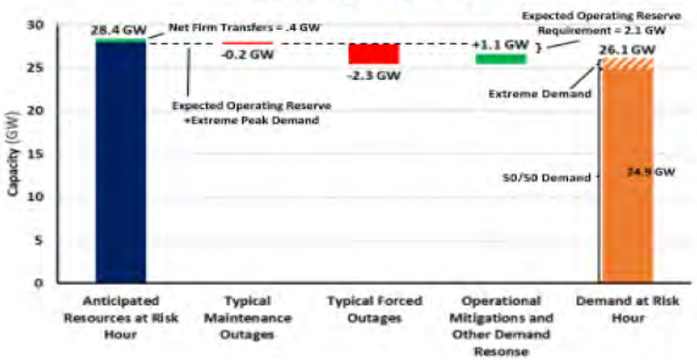
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Forecasted risk hour demand (50/50) and (90/10) extreme demand adder.

Maintenance Outages: Historical average of maintenance outages.

Typical Forced Outages: Based on historical average of forced outages for summer period.

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



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this SRA, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an installed reserve margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2026–2027 IRM at 24.5%.

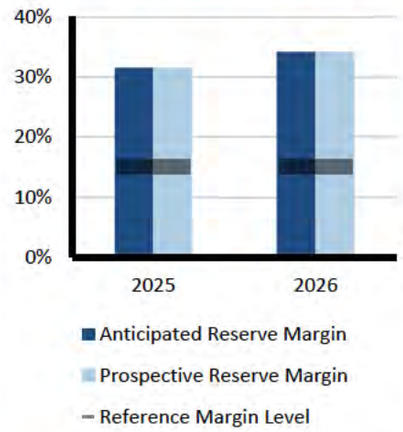
Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer.
- Adequate capacity margins are projected for the summer peak, and prospective transactions with neighbors should mitigate reliability concerns. Operating procedures should be sufficient to handle any issues that may occur.
- The preliminary results of the NPCC probabilistic assessment indicate that use of New York's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. The expected load and resource scenario resulted in negligible risks over the May to September summer period, with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE.
- In contrast, under the scenario of highest peak load and reduced resources, the estimated cumulative risk reached 0.655 days of LOLE, 1.996 hours of LOLH, and 1,255 MWh of EUE, with the greatest risks occurring in July and August.
- to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet needs for firm or non-firm transfers to address extreme system conditions

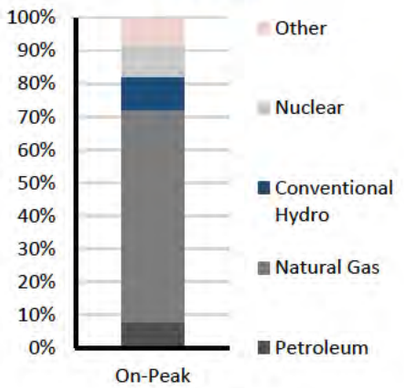
Risk Scenario Summary

The preliminary results of NPCC's probabilistic assessment indicate that New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected demand, if needed, to mitigate shortages during Summer 2026.

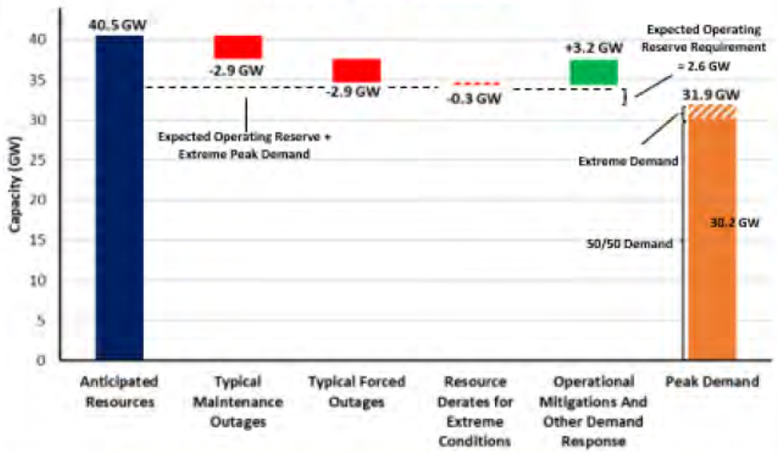
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: The risk period is at the time of peak demand.

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast. **Maintenance Outages:** Based on historical performance and the new NYISO capacity accreditation process.

Forced Outages: Based on historical five-year averages.

Extreme Derates: Estimated resources unavailable in extreme conditions.

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



NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

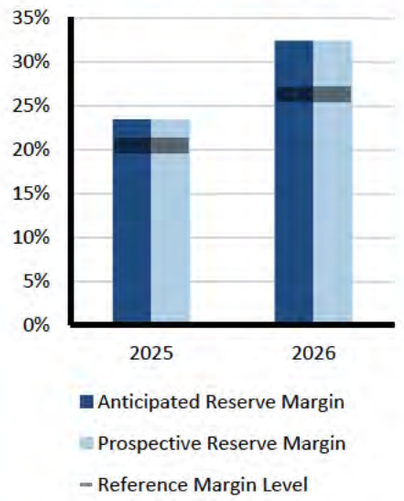
Highlights

- Ontario is well prepared for Summer 2026, and the IESO expects that the electricity system will remain reliable.
- Demand increased 2.7% over last year, driven in part by a rise in certain economic indicators, such as higher total employment, across the forecast horizon. However, uncertainty persists in the current economic environment with Ontario's largest trading partner.
- Existing-certain capacity is 8.4% higher than last year, reflecting the addition of new units. Established resource adequacy policy sets out a competitive strategy for securing new resources in the short, medium, and long terms. Also, Darlington G4 nuclear refurbishment was completed early and will be available for the summer period.
- Net firm capacity transfers increased 30.6% from Summer 2025. Although the capacity auction secured fewer imports for Summer 2026 compared to Summer 2025, IESO has chosen to utilize 300 MW of the 2015 Capacity Sharing Agreement with Hydro-Québec for the period commencing June 1, 2026, and ending September 30, 2026.
- Anticipated resources are projected 9% higher than Summer 2025 due to upgrades at existing natural gas facilities and new energy storage facilities anticipated to be coming on-line this summer.
- The preliminary results of NPCC's probabilistic assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.

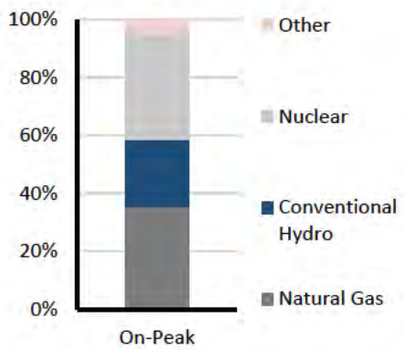
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

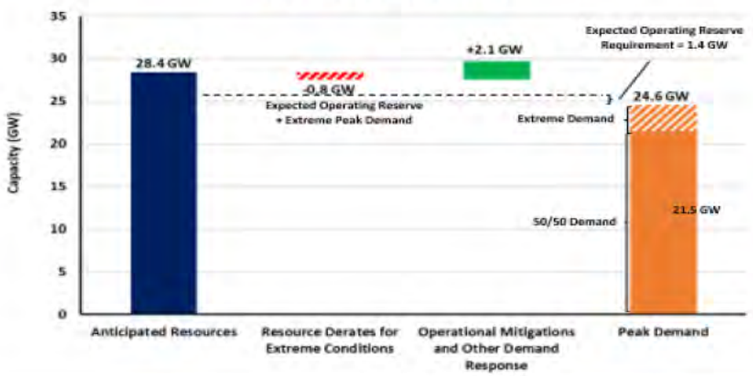
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modeled data.

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

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,100 MW for the On-Peak Risk Scenario, consisting of Imports, Public Appeals, and voltage reductions.



NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominantly hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

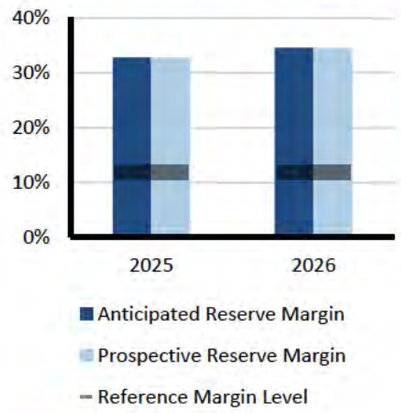
Highlights

- Québec is a winter-peaking hydroelectric system. Despite reduced generation because of reduced runoff in northern Québec since 2023, the Québec area expects no issues in meeting its operational needs this summer.
- Load (NID) is projected to decrease by 1% with respect to 2025.
- Net firm capacity exports have significantly increased (+1,018 MW) this year, as the CHPE is positioned to provide firm capacity to New York for the summer.
- There is a significant change to existing-certain capacity (3.7% or +1,192 MW). Hydro-Québec includes its planned outages in its certain capacity. This year, Hydro-Québec improved its modeling of its outages partially to account for its flexibility in managing outages; notably, the ability to recall certain outages to improve margins during peak events is highlighted.
- The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of operating procedures designed to mitigate resource shortages during Summer 2026. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking. The Québec area expects to be able to help other areas if needed.

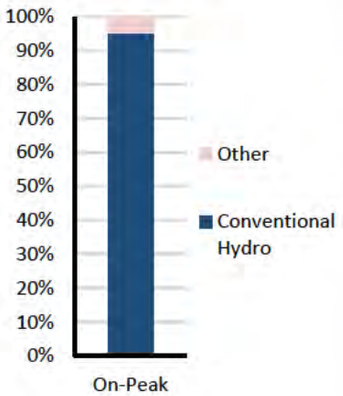
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

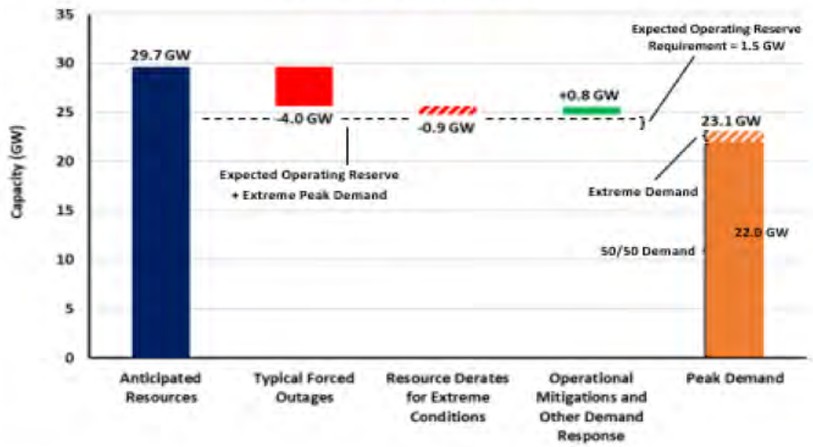
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Based on historical data and trending.

Extreme Derates: Estimated resources unavailable in extreme conditions.

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



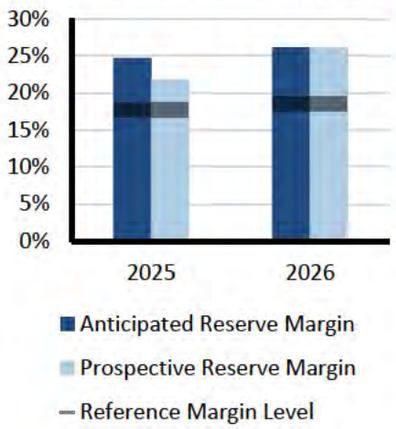
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and serves more than 67 million people. PJM is the area's BA, Transmission and Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Highlights

- PJM is expecting a low risk of resources falling below the required reserve requirement during Summer 2026.
- PJM is forecasting ~26% installed reserves (including expected committed demand resources), which is above the PJM reserve requirement margin of 18.6% that is necessary to meet the 1-day-in-10-years LOLE criterion. The highest risk for unserved energy is at peak demand hour.
- If extreme high temperatures are experienced, PJM anticipates the need for demand-response resources to help reduce load.
- New and better load forecasts and advancement of planned resources have improved PJM's reserve margin looking into this summer over previous assessments.
- The LOLH and EUE values reported in the 2024 LTRA for 2026 were 0.12 hours/year and 537.52 MWh/year, respectively. These values corresponded to a 17.8% operable margin (also reported in the 2024 LTRA). Since the expected actual reserve margin for the PJM system is 26% in 2026, the LOLH and EUE values associated with a 26% reserve margin are expected to be lower than those reported in the 2024 LTRA.

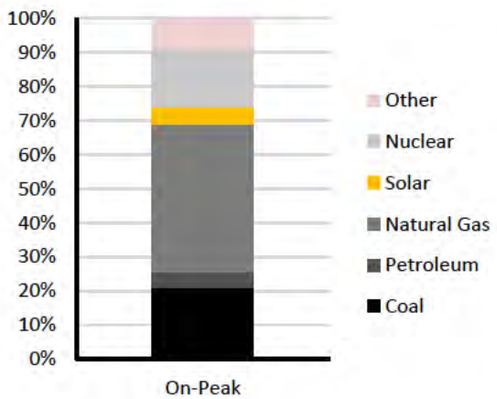
On-Peak Reserve Margin



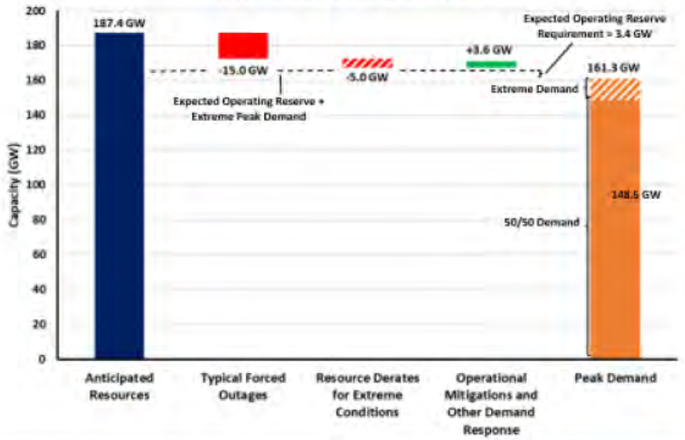
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Based on historical data and trending.

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

Operational Mitigations: A total of 3.6 GW estimated based on operational/emergency procedures. This includes 500 MWs of additional demand response that can be called upon during operating emergencies.



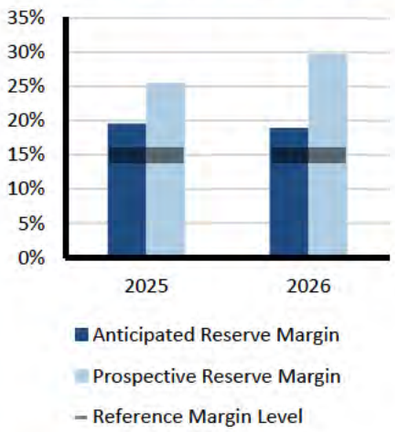
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, Tennessee, and Virginia. SERC-Central is a dual-peaking assessment area, experiencing peak electricity demand during both the summer and winter seasons. The PCs in this subregion include Associated Electric Cooperative Inc., Louisville Gas & Electric/Kentucky Utilities, Owensboro, KY Municipal Utilities, and the Tennessee Valley Authority. Other SERC member entities in this subregion include Brookfield/Smoky Mountain, Memphis Light, Gas and Water Division, and Nashville Electric Service.

Highlights

- No significant reliability concerns were identified.
- Modest load growth (~1–3%) is driven by residential, industrial, and emerging data center demand.
- Increased demand response (DR) results from new demand-side management (DSM) programs and large industrial load enrollments.
- Adequate capacity, transfers, resource assumptions and reserve margins remain sufficient to support reliability.
- Robust operational planning and coordination, with DSM/DR programs providing additional flexibility during peak conditions.
- ProbA results show negligible risk for this summer.

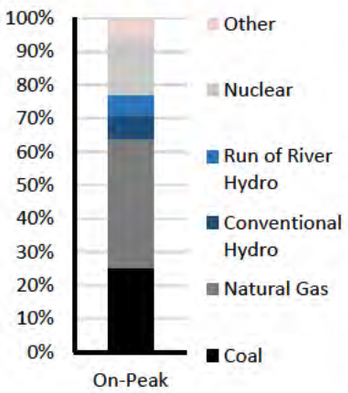
On-Peak Reserve Margin



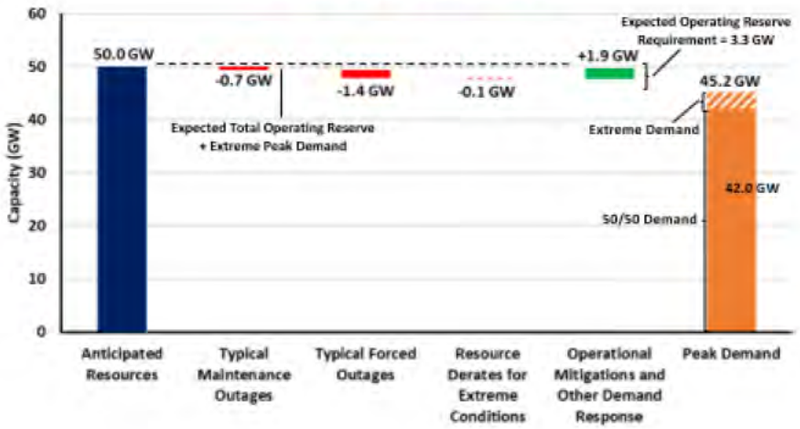
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

Operational Mitigations: 1.9 GW based on operational/emergency procedures.



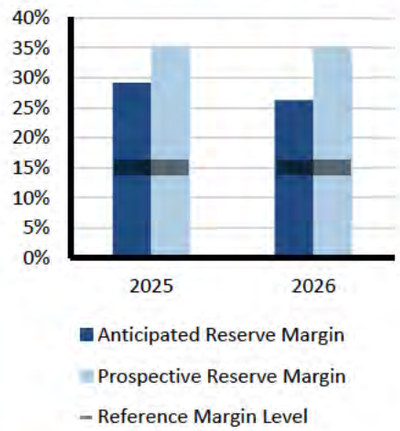
SERC-East

SERC-East is an assessment area within the SERC Regional Entity and includes North Carolina and South Carolina. SERC-East is a winter-peaking assessment area. The PCs in this subregion include Cube Hydro Carolinas LLC, Dominion Energy South Carolina Inc., Duke Energy Carolinas LLC, Duke Energy Progress LLC, and the South Carolina Public Service Authority (Santee Cooper). Other SERC member entities in this subregion include the Cube Hydro Carolinas-Yadkin Division and Southeastern Power Administration.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain adequate for Summer 2026.
- Fuel supply, generation availability, and transmission operations are expected to be adequate, with no major outages anticipated to impact reliability.
- Minimal changes are expected in demand and resource mix; reserve margins remain above planning targets despite updated solar/storage accreditation.
- Strong coordination processes and established operating procedures support reliable peak demand management.
- ProbA results show negligible risk for this summer.

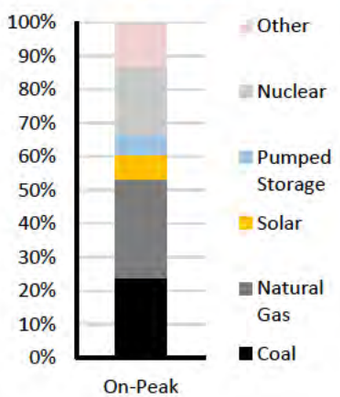
On-Peak Reserve Margin



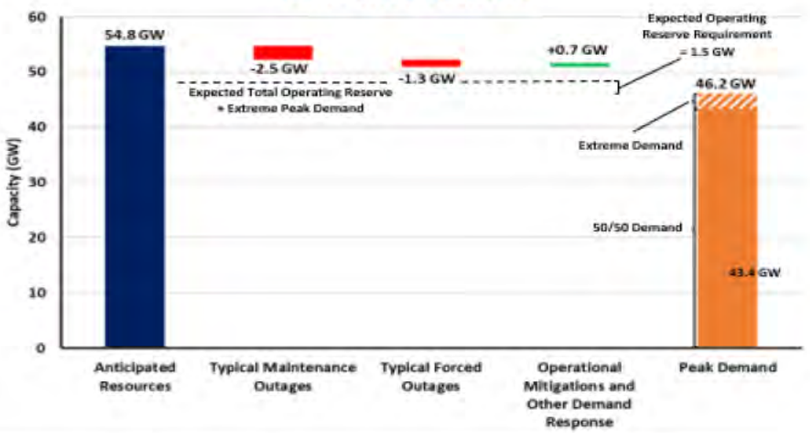
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

Operational Mitigations: A total of 728 MW based on operational/emergency procedures.



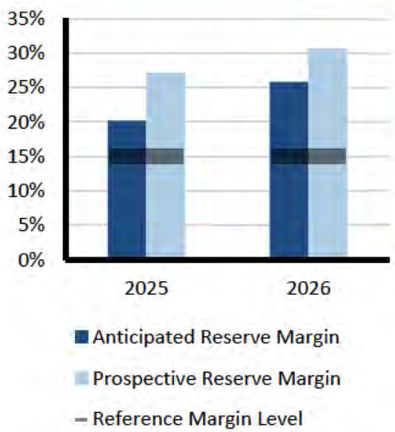
SERC-Florida Peninsula

SERC-Florida Peninsula is an assessment area within the SERC Regional Entity and includes all of Florida. SERC-Florida Peninsula is a summer-peaking assessment area. The PCs in this subregion include Duke Energy Florida LLC, the Florida Municipal Power Agency, Florida Power & Light Company, Florida Reliability Coordinating Council Inc., Gainesville Regional Utilities, the City of Homestead, JEA, Lakeland Electric, the Orlando Utilities Commission, Seminole Electric Cooperative, the City of Tallahassee, and Tampa Electric Company.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain stable for Summer 2026.
- There is an adequate demand and capacity outlook, with minimal year-over-year changes and no significant operational risks.
- There is strong resource adequacy, with projected reserve margins (~26%) well above the 15% reference margin.
- DR (~3,350 MW available) and established coordination practices support peak demand and emergency preparedness.
- ProbA results show negligible risk for this summer.

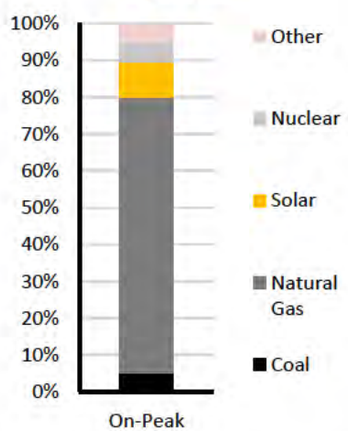
On-Peak Reserve Margin



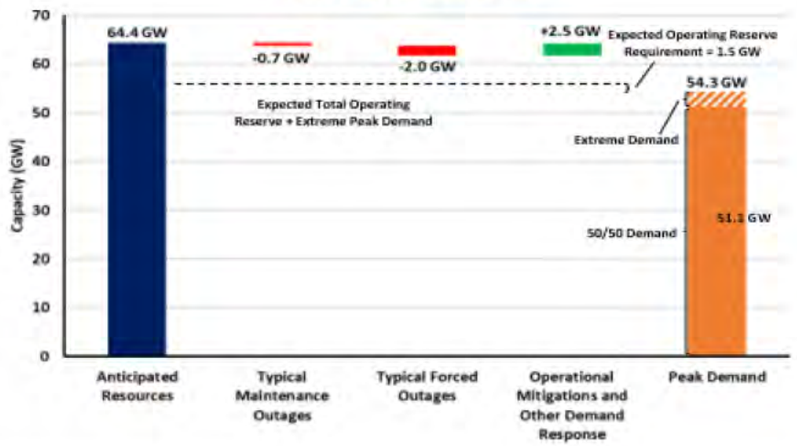
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

Operational Mitigations: A total of 2.5 GW based on operational/emergency procedures.



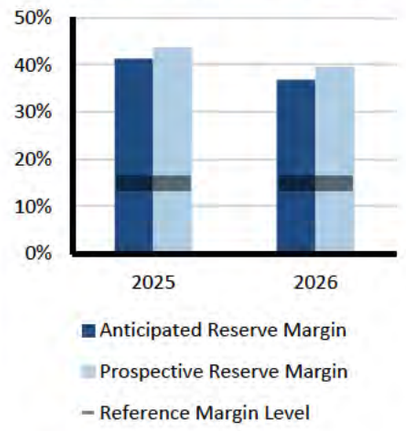
SERC-Southeast

SERC-Southeast is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Florida, Georgia, and Mississippi. SERC-Southeast is a summer-peaking assessment area. The PCs in this subregion include Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth Energy Cooperative, and Southern Company Services, Inc. - Trans.

Highlights

- No significant reliability risks were identified; fuel supply and generation portfolios remain diverse and adequate.
- Natural gas pipeline constraints and increasing solar penetration present manageable operational considerations, not reliability threats.
- Moderate load growth (~1–3%), driven by economic conditions, residential and commercial expansion, and emerging data center load.
- Limited reliance on DR; existing operating practices and planning processes are sufficient to meet peak demand.
- ProbA results show negligible risk for this summer.

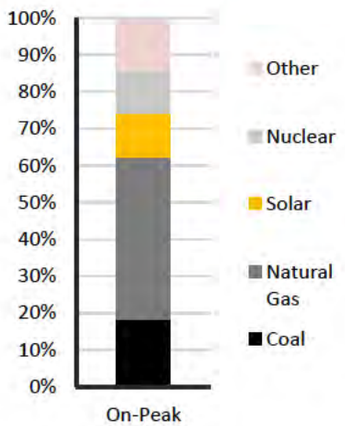
On-Peak Reserve Margin



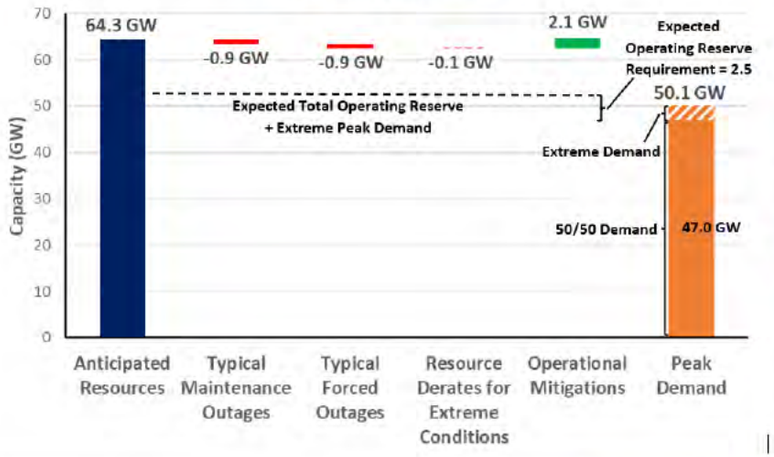
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

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

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

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational Mitigations: A total of 2.1 GW based on operational/emergency procedures.



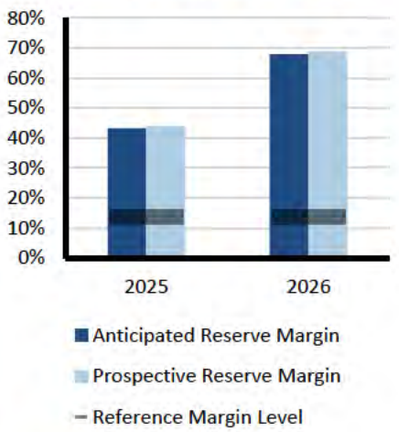
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,460 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

- Given an Anticipated Reserve Margin of 67.9% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for the August peak load hour given expected normal system summer conditions.
- Continued growth in load and intermittent resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads are high.
- The probability of an EEA during the expected August (and summer) peak load day continues to drop relative to previous SRAs due to continued robust growth in battery energy storage capacity (up 2,677 MW year-on-year as of March 2026). The EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 0.43%, down from 3.1% previously.
- The projected EEA risk does not account for regional constraints in Far West Texas, which may lead to a reliance on price-responsive demand in certain low-generation scenarios.
- An identified risk is the potential of newly interconnected large loads (mainly data centers and crypto-mining facilities) to trip and potentially cause grid stability problems. ERCOT has implemented mandatory ride-through capabilities and requires dynamic model submissions, among other solutions, to address this risk.
- The risk assessment process for this SRA will be the same as ERCOT's upcoming August 2026 Monthly Outlook of Resource Adequacy (MORA) to be released on June 5.

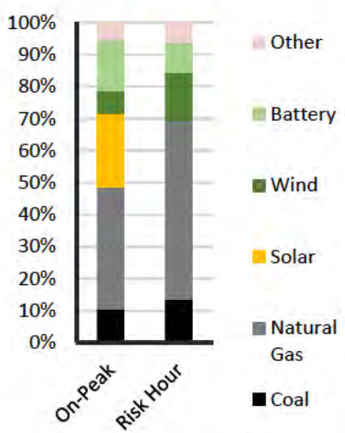
On-Peak Reserve Margin



Risk Scenario Summary

The risk of having to declare an EEA for hour 21 is low (0.43%), according to ERCOT's probabilistic reserve risk model (PRRM) simulation results. The highest risk hour for the peak load day in August (which is also the expected summer peak load day).

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Hour: The highest risk hour, HE 2100 (9:00 pm CDT).

Demand Scenarios: Net internal demand, and an adjustment to extreme demand based on the 95th percentile of the PRRM's distribution of load simulation outcomes for the highest-risk hour (HE 2100).

Forced Outages: The adjustment is the 95th percentile of 10,000 daily thermal forced outage values generated by the PRRM, less the 50th percentile value.

Low-Wind Scenario: The adjustment is the 50th percentile of 10,000 wind generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Extreme Derates: The adjustment is the 50th percentile of 10,000 solar generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Operational Mitigations: Additional capacity from switchable generation and additional imports.



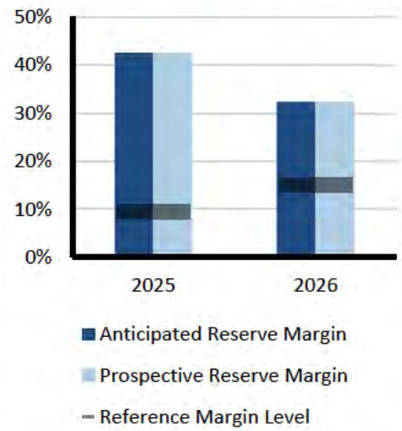
WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's planning entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas—Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. Additionally, WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak demand is projected to increase by 2.1% over last summer's forecast.
- Wide-area heat events and wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.

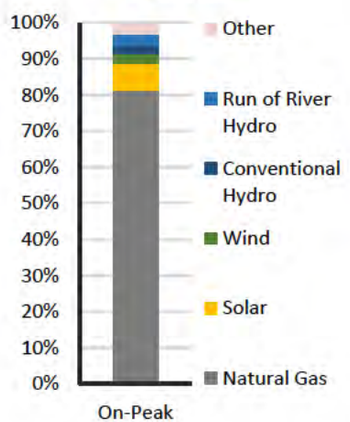
On-Peak Reserve Margin



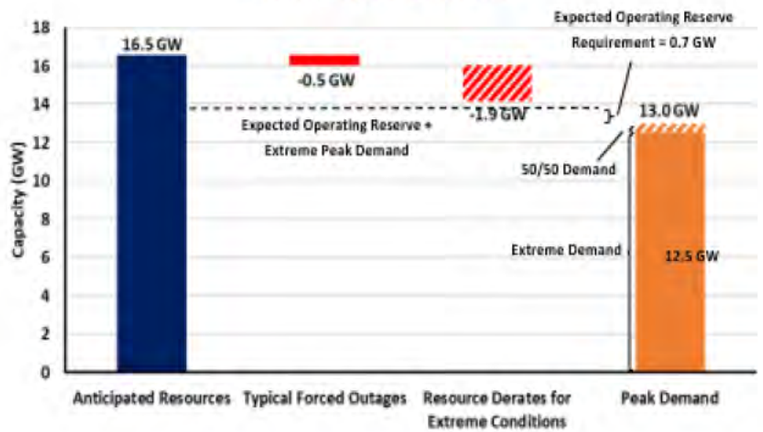
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages.

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



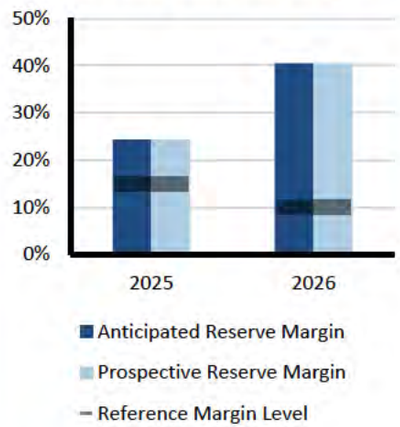
WECC-Basin

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

Highlights

- WECC-Basin has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Wildfires remain a reliability concern for the region, particularly in areas with remote generation such as remotely located hydro. Mitigation programs such as hardening and public safety shutoff programs are in place.
- Extreme temperatures pose a risk to the area, impacting load levels and renewable variability. WECC-Basin is positioned to rely on imports during such conditions, which also poses a risk of concurrent impacts should neighbors experience similar conditions.
- Load forecasts for the area are projected to be 2.5% higher than 2025 Summer actuals.
- Wind, solar, and energy storage resources continue to grow.
- Reserve margins are not anticipated to fall below the 15% Reference Margin Level for 2026 Summer. Both Anticipated and Prospective Reserve Margins are expected to be adequate at 37.6%

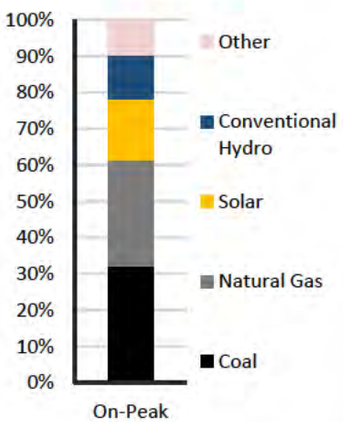
On-Peak Reserve Margin



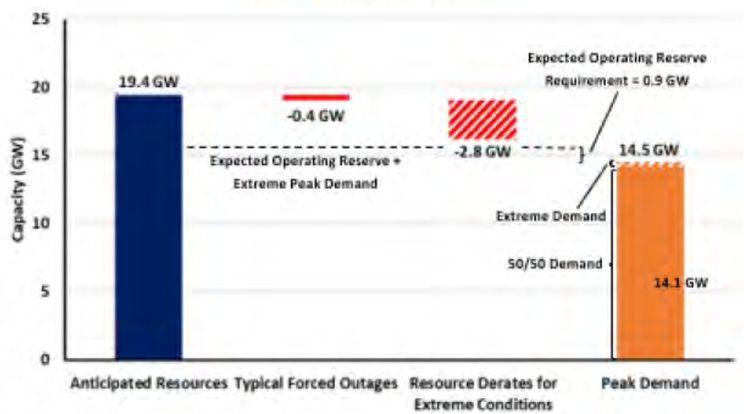
Risk Scenario Summary

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

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages.

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



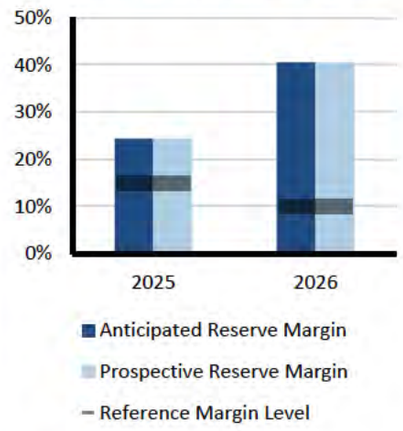
WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 32 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas—the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during the winter season.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- WECC's probabilistic analysis shows no LOLH nor EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to increase 2.4% over last summer's forecast while anticipated resources increase by 15.7%.
- Wide-area heat events or wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Energy imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.

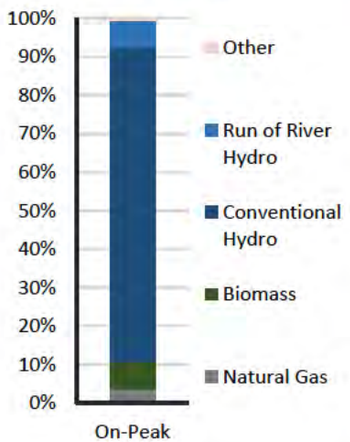
On-Peak Reserve Margin



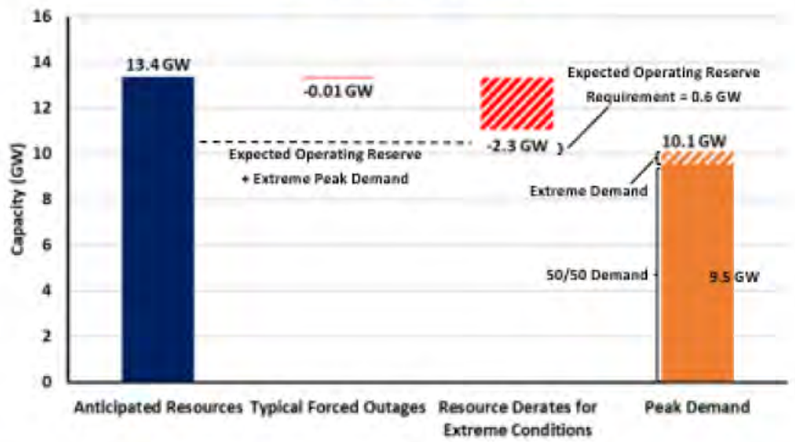
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages.

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



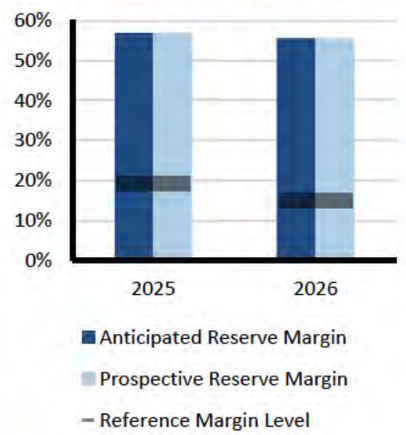
WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, the Los Angeles Department of Water and Power, the Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Extreme heat and wildfires exacerbated by continued climate change may impact generation and transmission resources and remain a reliability concern.
- Cyber attacks pose significant reliability concerns for the area.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Inverter-based resource (IBR) output variability remains a concern, such as from the evening ramp requirements from declining solar and Santa Ana winds, which can overspeed wind turbines, requiring them to curtail.

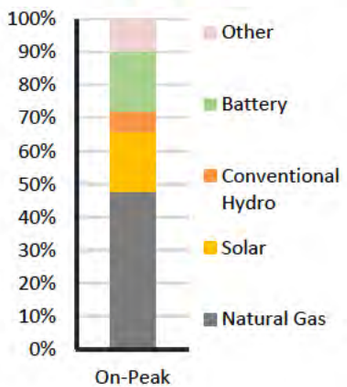
On-Peak Reserve Margin



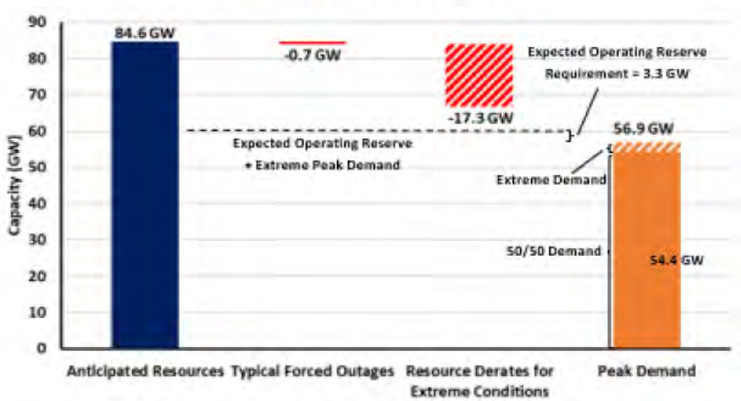
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: On-peak risk scenario.

Demand Scenarios: 50/50 and 90/10. Significant difference in delta from 2025. May be from switch to SERVM and weather year adjustment taken out.

Forced Outages: Based on historical average of forced outages for a specified period/conditions (e.g., average of forced outages for June through September weekdays, over the past three years), or area-specific methodology for determining anticipated forced outages for non-intermittent resources (e.g., thermal, hydro).

Extreme Derates: Capacity derate for resources for extreme conditions. The derate accounts for reduced capacity contributions due to performance in extreme conditions for thermal, wind, PV, storage, and other.



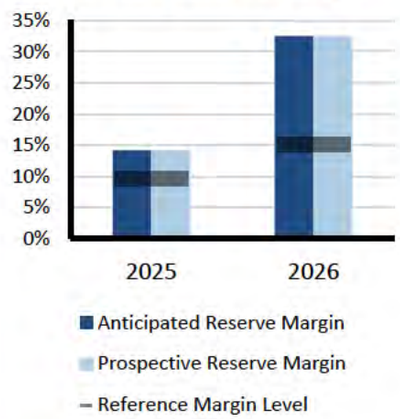
WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes Centro Nacional de Control de Energía (CENACE). It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- WECC-Mexico has added an additional 1 GW of natural-gas-fired resources since last summer, greatly improving its outlook from the *2025 SRA*.
- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions. Anticipated resources are projected to be 15.5% higher.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EEA and a request for assistance from RC West.
- Some generating units have reached advanced operational age, resulting in an observable increase in the forced outage rate. This condition increases the risk of capacity shortfalls and may compromise system reliability during peak seasonal demand.

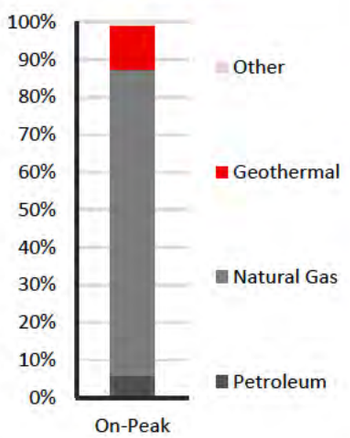
On-Peak Reserve Margin



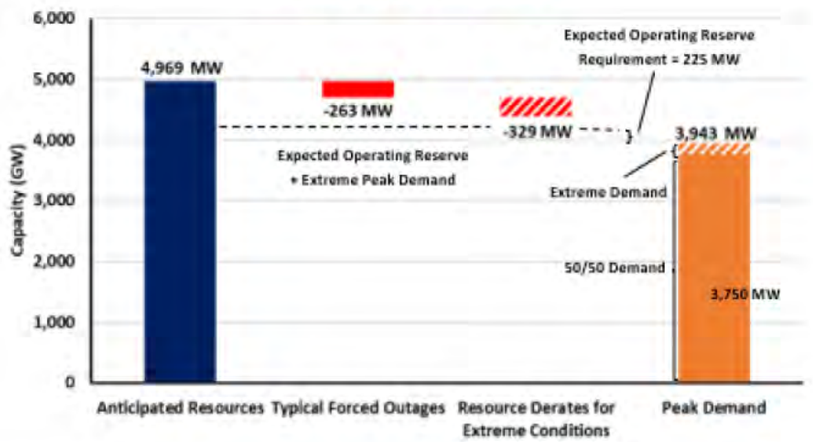
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages.

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



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

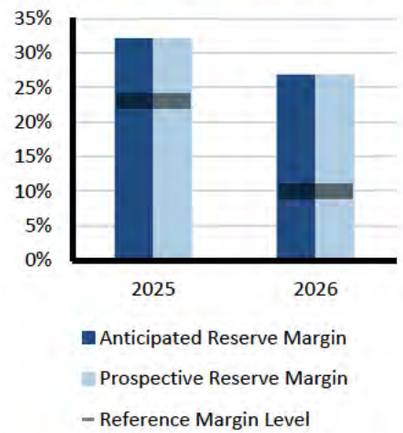
Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
- The EUE and LOLH occurs in hours 17 and 18 in August and September, with the vast majority September hour 18.
- Peak net internal demand is projected to grow 4.6% over last summer's forecasts; however, anticipated resources are showing just a 1.5% increase in energy availability, leading to tighter margins.
- Wide-area heat events, wildfires, and low snow-water equivalents due to a changing climate impact generation resource and transmission availability and remain a continued reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads or derates, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- There have been instances where operators had difficulty maintaining frequency due to sudden disconnection of large loads necessitating additional regulation capability.

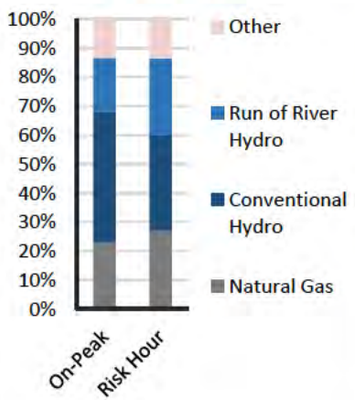
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under the assessed extreme scenarios. WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions, placing the area at risk of shortfall during extreme conditions.

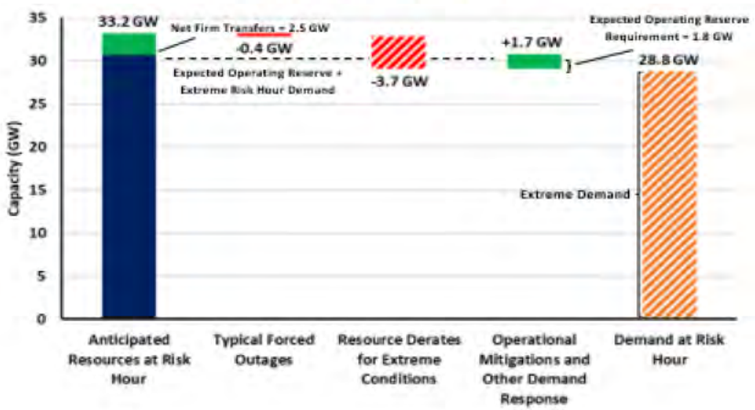
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Modeled output depicting load-loss event from the probabilistic model.

Risk Period: Off-peak highest risk hour is primarily 6 p.m. in September.

Demand Scenarios: Modeled load for the risk hour during load-loss event.

Typical Forced Outages: Based on historical average of forced outages for the period.

Extreme Derates: Modeled outage and derates to account for underperformance of resources at the risk hour.

Operational Mitigations: An operational procedure used to mitigate extreme conditions not already included in the margins is the depletion of operating reserves by 1.7 GW. WECC did not use an operational model prior to this year's report, and it the first time the model includes operating reserves of 6% withheld through unserved energy.



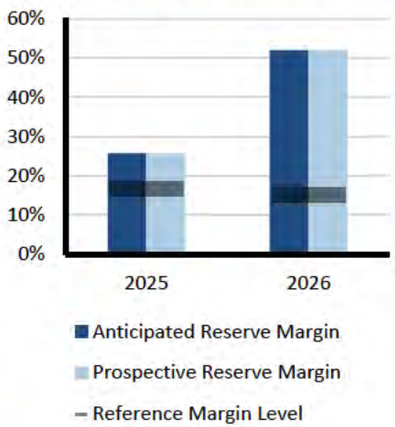
WECC-Rocky Mountain

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 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- WECC-Rocky Mountain has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- Wildfires in the region, along with extreme heat conditions for the summer, pose the greatest reliability risk scenario for the Rocky Mountains. These conditions can impact rural co-ops disproportionately.
- The existing certain and Anticipated Reserve Margins are projected to be at 43% and 52%, respectively, above the established 15% for the summer. Projections for summer load indicate minimal growth from 2025 and are 0.6% higher than 2025 Summer peak load conditions.

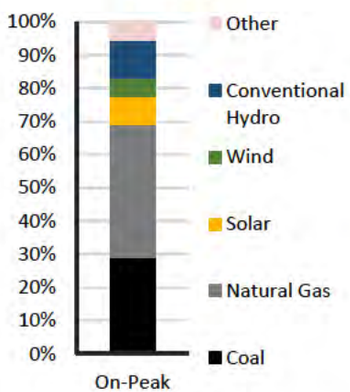
On-Peak Reserve Margin



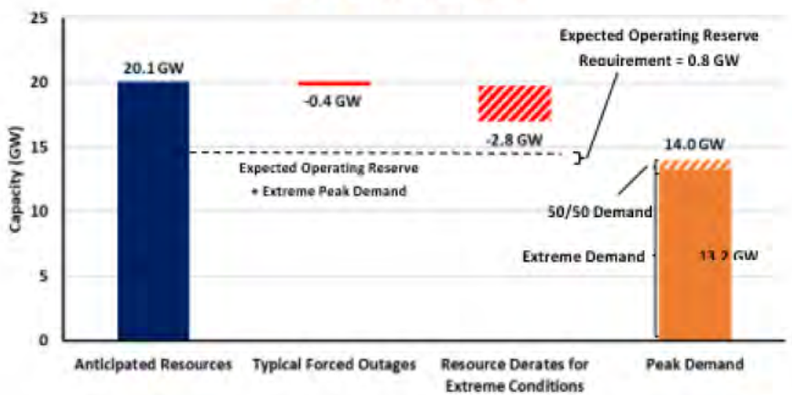
Risk Scenario Summary

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

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages.

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



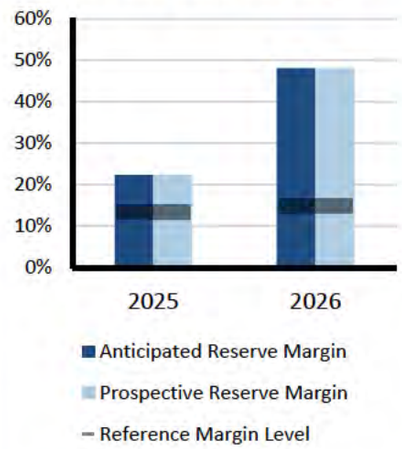
WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to grow 9.5% over last summer's forecasts. DR availability has also increased from 199 MW to 364 MW.
- Anticipated resource capacity is expected to be 32.5% higher than last summer, mostly due to methodological changes to capacity of incoming future resources. Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Elevated forced outage rates due to the amount of aging generation capacity along with extensive overhaul requirements can keep resources out of service for extended periods of time.
- Extreme heat events can result in prolonged periods of elevated demand, derates to thermal generation, and—given the large area that heat waves cover—drastically reduced import capability from neighboring areas. The area also faces significant wildland fire potential this summer. Wildfires have the potential to interrupt large numbers of customers by damaging generation, transmission, and distribution assets.

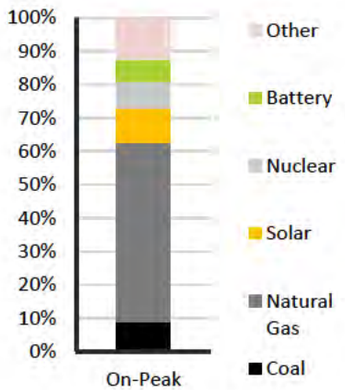
On-Peak Reserve Margin



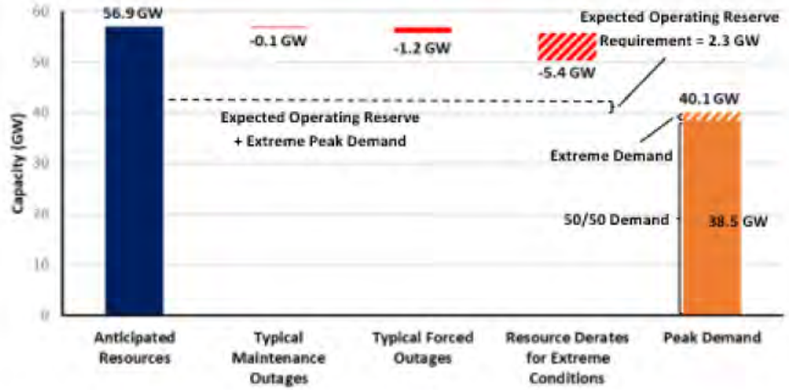
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Forced Outages: Average seasonal outages.

Extreme Derates: Using (90/10) scenario.

Data Concepts and Assumptions

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

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[17] or total internal demand for the summer and winter of each year.[18]
• Total internal demand projections are based on normal weather (50/50 distribution)[19] and are provided on a coincident[20] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

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

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

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

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

Resource Assumptions

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

Anticipated Resources:

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

Prospective Resources: Includes all anticipated resources plus the following:

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

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

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

Seasonal Risk Scenario Chart Description

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

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

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

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

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[21] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for Summer 2026 as shown in Figure 5.

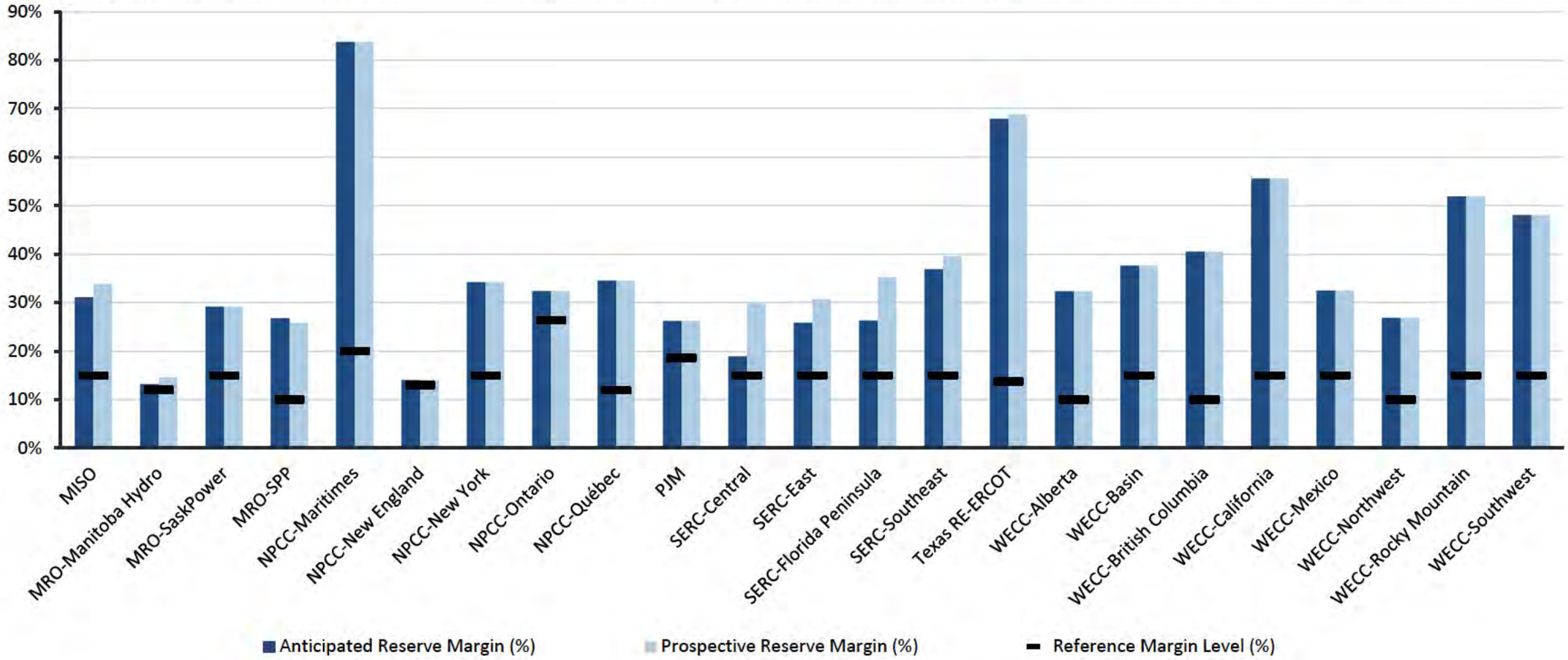


Figure 5: Summer 2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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

Changes from Year to Year

Figure 6 provides the relative change in the forecast Anticipated Reserve Margins from the 2025 Summer to the 2026 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

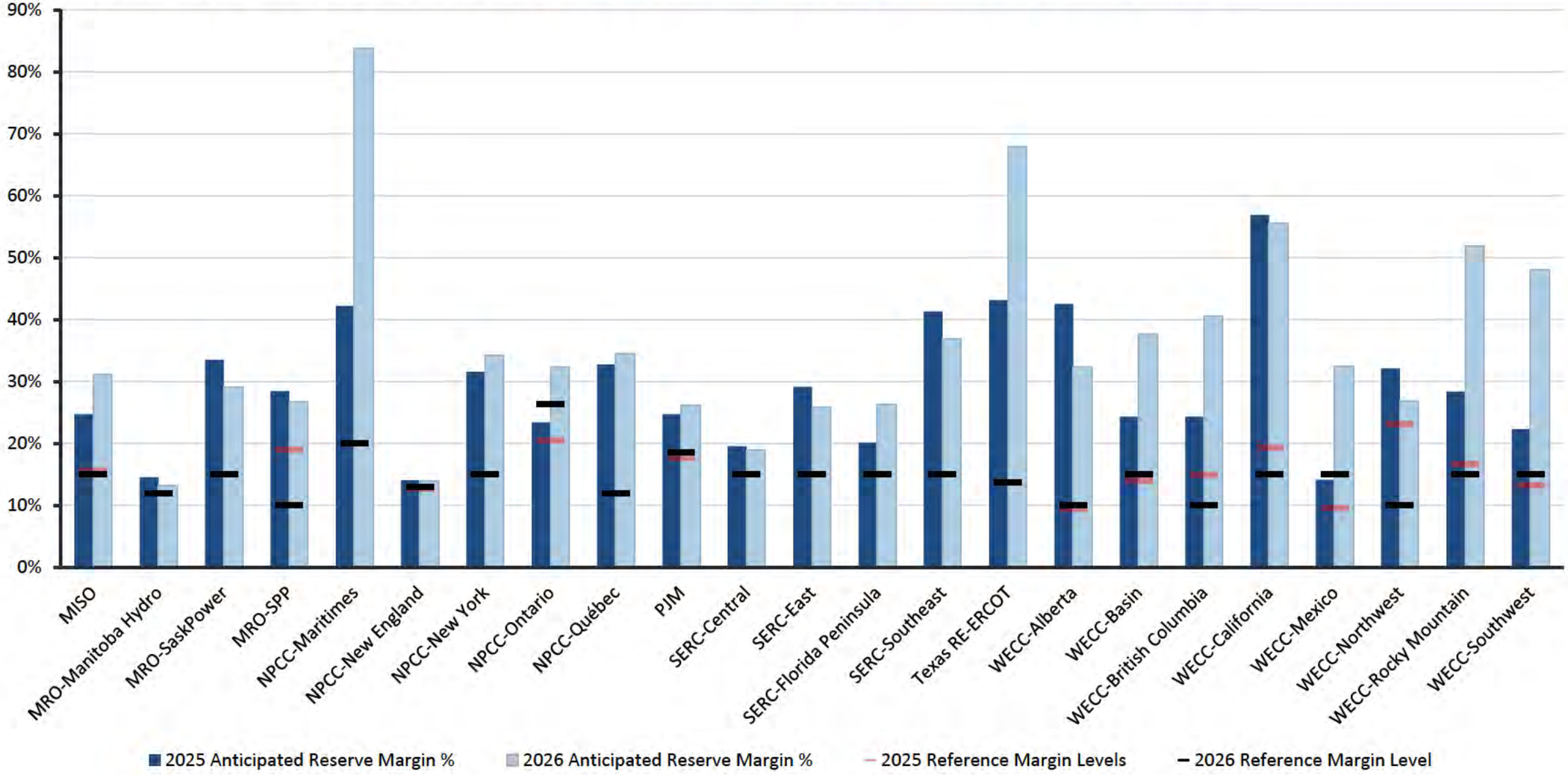


Figure 6: Summer 2025 and Summer 2026 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 7.[22] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

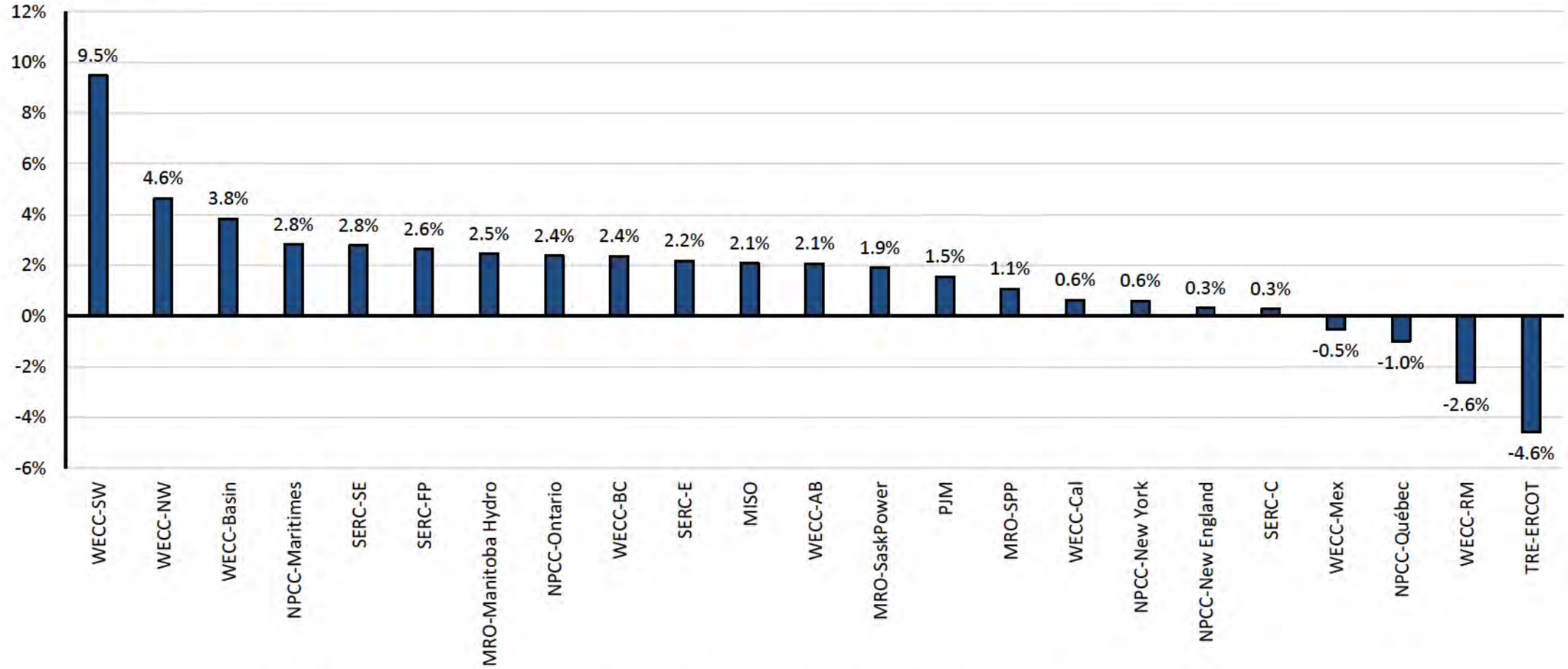


Figure 7: Changes in Net Internal Demand—Summer 2025 Forecast Compared to Summer 2026 Forecast

[22] The lower demand forecast in Texas RE-ERCOT is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads.

Demand and Resource Tables

The tables in this section contain peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area.

MISO			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	125,313	127,824	2.0%
Demand Response: Available	9,004	9,100	1.1%
Net Internal Demand	116,309	118,725	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	142,793	152,382	6.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,280	3,259	42.9%
Anticipated Resources	145,073	155,641	7.3%
Existing-Other Capacity	1,190	0	-100.0%
Prospective Resources	148,543	158,900	7.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.7%	31.1%	6.4
Prospective Reserve Margin	27.7%	33.8%	6.1
Reference Margin Level	15.7%	15.0%	-0.7

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,377	3,611	6.9%
Demand Response: Available	0	151	-
Net Internal Demand	3,377	3,460	2.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,583	5,631	0.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,714	-1,714	0.0%
Anticipated Resources	3,869	3,917	1.2%
Existing-Other Capacity	21	46	114.6%
Prospective Resources	3,890	3,963	1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.6%	13.2%	-1.4
Prospective Reserve Margin	15.2%	14.5%	-0.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,620	3,688	1.9%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,570	3,638	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,477	4,409	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,767	4,699	-1.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,767	4,699	-1.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	29.2%	-4.4
Prospective Reserve Margin	33.5%	29.2%	-4.4
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,168	57,122	1.7%
Demand Response: Available	1,408	1,772	25.8%
Net Internal Demand	54,760	55,350	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,549	69,317	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-201	851	-524.0%
Anticipated Resources	70,348	70,168	-0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	69,801	69,621	-0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.5%	26.8%	-1.7
Prospective Reserve Margin	27.5%	25.8%	-1.7
Reference Margin Level	19.0%	10.0%	-9.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,584	3,691	3.0%
Demand Response: Available	327	342	4.6%
Net Internal Demand	3,257	3,349	2.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,348	5,721	31.6%
Tier 1 Planned Capacity	220	280	27.3%
Net Firm Capacity Transfers	63	153	142.9%
Anticipated Resources	4,631	6,154	32.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,631	6,154	32.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.2%	83.8%	41.6
Prospective Reserve Margin	42.2%	83.8%	41.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,471	31,578	0.3%
Demand Response: Available	1,487	1,415	-4.8%
Net Internal Demand	29,984	30,163	0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,682	37,324	-1.0%
Tier 1 Planned Capacity	0	210	-
Net Firm Capacity Transfers	1,769	2,941	66.3%
Anticipated Resources	39,451	40,475	2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	39,451	40,475	2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.6%	34.2%	2.6
Prospective Reserve Margin	31.6%	34.2%	2.6
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,202	25,228	0.1%
Demand Response: Available	399	346	-13.3%
Net Internal Demand	24,803	24,882	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,054	27,667	2.3%
Tier 1 Planned Capacity	0	295	-
Net Firm Capacity Transfers	1,245	409	-67.1%
Anticipated Resources	28,299	28,371	0.3%
Existing-Other Capacity	668	0	-100.0%
Prospective Resources	28,967	28,371	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	14.0%	-0.1
Prospective Reserve Margin	16.8%	14.0%	-2.8
Reference Margin Level	12.7%	13.0%	0.3

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,955	22,545	2.7%
Demand Response: Available	998	1,088	9.1%
Net Internal Demand	20,957	21,457	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	24,760	26,837	8.4%
Tier 1 Planned Capacity	413	670	62.2%
Net Firm Capacity Transfers	689	900	30.6%
Anticipated Resources	25,862	28,407	9.8%
Existing-Other Capacity	0	0	-
Prospective Resources	25,862	28,407	9.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.4%	32.4%	9.0
Prospective Reserve Margin	23.4%	32.4%	9.0
Reference Margin Level	20.5%	26.3%	5.9

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,283	22,490	-3.4%
Demand Response: Available	1,020	450	-55.9%
Net Internal Demand	22,263	22,040	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,132	33,324	3.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,582	-3,670	42.1%
Anticipated Resources	29,550	29,655	0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	29,550	29,655	0.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.7%	34.5%	1.8
Prospective Reserve Margin	32.7%	34.5%	1.8
Reference Margin Level	11.9%	11.9%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,765	44,369	3.8%
Demand Response: Available	864	2,354	172.3%
Net Internal Demand	41,900	42,016	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	46,949	47,603	1.4%
Tier 1 Planned Capacity	592	202	-66.0%
Net Firm Capacity Transfers	2,554	2,158	-15.5%
Anticipated Resources	50,095	49,962	-0.3%
Existing-Other Capacity	2,475	4,546	83.7%
Prospective Resources	52,570	54,508	3.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.6%	18.9%	-0.6
Prospective Reserve Margin	25.5%	29.7%	4.3
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	154,144	156,373	1.4%
Demand Response: Available	7,898	7,864	-0.4%
Net Internal Demand	146,246	148,509	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	186,638	188,854	1.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-4,200	-1,427	-66.0%
Anticipated Resources	182,438	187,427	2.7%
Existing-Other Capacity	0	0	-
Prospective Resources	178,238	187,427	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.7%	26.2%	1.5
Prospective Reserve Margin	21.9%	26.2%	4.3
Reference Margin Level	17.7%	18.6%	0.9

SERC-East			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,015	44,765	1.7%
Demand Response: Available	1,558	1,387	-11.0%
Net Internal Demand	42,457	43,378	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,665	54,637	0.0%
Tier 1 Planned Capacity	17	23	36.9%
Net Firm Capacity Transfers	150	119	-20.7%
Anticipated Resources	54,832	54,780	-0.1%
Existing-Other Capacity	2,628	3,890	48.1%
Prospective Resources	57,459	58,670	2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	26.3%	-2.8
Prospective Reserve Margin	35.3%	35.3%	0.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,987	54,477	2.8%
Demand Response: Available	3,158	3,335	5.6%
Net Internal Demand	49,829	51,142	2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,395	64,163	8.0%
Tier 1 Planned Capacity	102	58	-43.4%
Net Firm Capacity Transfers	381	131	-65.6%
Anticipated Resources	59,878	64,352	7.5%
Existing-Other Capacity	3,482	2,481	-28.7%
Prospective Resources	63,360	66,833	5.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	25.8%	5.7
Prospective Reserve Margin	27.2%	30.7%	3.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	85,151	83,224	-2.3%
Demand Response: Available	3,292	5,100	54.9%
Net Internal Demand	81,859	78,124	-4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	112,321	125,975	12.2%
Tier 1 Planned Capacity	4,854	5,189	6.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	117,195	131,184	11.9%
Existing-Other Capacity	0	0	-
Prospective Resources	117,770	131,903	12.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	43.2%	67.9%	24.8
Prospective Reserve Margin	43.9%	68.8%	25.0
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	47,049	48,625	3.3%
Demand Response: Available	1,338	1,642	22.7%
Net Internal Demand	45,711	46,983	2.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	64,111	64,391	0.4%
Tier 1 Planned Capacity	0	375	-
Net Firm Capacity Transfers	489	-467	-195.5%
Anticipated Resources	64,600	64,299	-0.5%
Existing-Other Capacity	1,077	1,277	18.7%
Prospective Resources	65,676	65,576	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.3%	36.9%	-4.5
Prospective Reserve Margin	43.7%	39.6%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,246	12,499	2.1%
Demand Response: Available	0	0	-
Net Internal Demand	12,246	12,499	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,176	16,179	-5.8%
Tier 1 Planned Capacity	281	323	15.1%
Net Firm Capacity Transfers	0	40	-
Anticipated Resources	17,457	16,542	-5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,457	16,542	-5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.6%	32.3%	-10.2
Prospective Reserve Margin	42.6%	32.3%	-10.2
Reference Margin Level	9.4%	15.0%	5.6

WECC-BC			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,309	9,529	2.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,309	9,529	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,313	12,307	8.8%
Tier 1 Planned Capacity	260	469	80.3%
Net Firm Capacity Transfers	0	612	-
Anticipated Resources	11,573	13,388	15.7%
Existing-Other Capacity	0	0	-
Prospective Resources	11,573	13,388	15.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	40.5%	16.2
Prospective Reserve Margin	24.3%	40.5%	16.2
Reference Margin Level	14.9%	10.0%	-4.9

WECC-California			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,797	55,073	0.5%
Demand Response: Available	746	685	-8.2%
Net Internal Demand	54,051	54,388	0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	75,726	78,788	4.0%
Tier 1 Planned Capacity	8,470	2,085	-75.4%
Net Firm Capacity Transfers	598	3,751	527.2%
Anticipated Resources	84,794	84,623	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	84,794	84,623	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	56.9%	55.6%	-1.3
Prospective Reserve Margin	56.9%	55.6%	-1.3
Reference Margin Level	19.2%	15.0%	-4.2

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	35,321	38,814	9.9%
Demand Response: Available	199	364	82.9%
Net Internal Demand	35,122	38,451	9.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,300	46,476	15.3%
Tier 1 Planned Capacity	1,966	6,667	239.1%
Net Firm Capacity Transfers	695	3,791	445.4%
Anticipated Resources	42,961	56,934	32.5%
Existing-Other Capacity	0	0	-
Prospective Resources	42,961	56,934	32.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.3%	48.1%	25.8
Prospective Reserve Margin	22.3%	48.1%	25.8
Reference Margin Level	13.3%	15.0%	1.7

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	29,157	30,479	4.5%
Demand Response: Available	30	2	-93.3%
Net Internal Demand	29,127	30,477	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	36,388	35,708	-1.9%
Tier 1 Planned Capacity	844	477	-43.5%
Net Firm Capacity Transfers	1,249	2,483	98.8%
Anticipated Resources	38,481	38,668	0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	38,481	38,668	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.1%	26.9%	-5.2
Prospective Reserve Margin	32.1%	26.9%	-5.2
Reference Margin Level	23.1%	10.0%	-13.1

WECC-Basin			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	14,214	14,564	2.5%
Demand Response: Available	620	448	-27.7%
Net Internal Demand	13,594	14,116	3.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,923	16,759	12.3%
Tier 1 Planned Capacity	704	1,382	96.3%
Net Firm Capacity Transfers	1,274	1,288	1.1%
Anticipated Resources	16,901	19,429	15.0%
Existing-Other Capacity	0	0	-
Prospective Resources	16,901	19,429	15.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	37.6%	13.3
Prospective Reserve Margin	24.3%	37.6%	13.3
Reference Margin Level	14.0%	15.0%	1.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,848	13,516	-2.4%
Demand Response: Available	284	310	9.1%
Net Internal Demand	13,564	13,206	-2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,312	18,363	6.1%
Tier 1 Planned Capacity	104	1,206	1059.6%
Net Firm Capacity Transfers	0	495	-
Anticipated Resources	17,416	20,063	15.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,415	20,063	15.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.4%	51.9%	23.5
Prospective Reserve Margin	28.4%	51.9%	23.5
Reference Margin Level	16.7%	15.0%	-1.7

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,770	3,750	-0.5%
Demand Response: Available	0	0	-
Net Internal Demand	3,770	3,750	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,303	4,761	10.6%
Tier 1 Planned Capacity	0	765	-
Net Firm Capacity Transfers	0	-557	-
Anticipated Resources	4,303	4,969	15.5%
Existing-Other Capacity	0	0	-
Prospective Resources	4,303	4,969	15.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	32.5%	18.4
Prospective Reserve Margin	14.1%	32.5%	18.4
Reference Margin Level	9.6%	15.0%	5.4

Variable Energy Resource Contributions

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

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Run-of-River Hydro	Expected Run-of-River Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	32,066	5,611	17%	20,419	12,322	60%	1,294	770	60%	3,560	3,457	97%
MRO-Manitoba Hydro*	259	47	18%	-	-	0%	202	-	0%	-	-	0%
MRO-SaskPower	816	319	39%	30	9	28%	121	74	61%	-	-	0%
MRO-SPP	35,760	8,114	23%	3,926	2,139	54%	113	66	59%	1,318	1,113	84%
NPCC-Maritimes	1,341	423	32%	148	80	54%	1,316	1,316	100%	162	106	65%
NPCC-New England	2,431	424	17%	3,609	1,728	48%	584	287	49%	723	686	95%
NPCC-New York	2,598	417	16%	661	283	43%	914	354	39%	23	-	0%
NPCC-Ontario*	4,943	735	15%	478	66	14%	-	-	0%	451	226	50%
NPCC-Québec*	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
PJM	13,855	4,570	33%	16,852	9,951	59%	2,505	2,505	100%	256	238	93%
SERC-Central	1,324	370	28%	2,303	1,446	63%	4,979	3,213	65%	100	100	100%
SERC-East	-	-	0%	7,843	4,205	54%	3,096	3,033	98%	323	235	73%
SERC-Florida Peninsula	-	-	0%	13,502	6,276	46%	-	-	0%	1,177	1,145	97%
SERC-Southeast	-	-	0%	9,412	8,087	86%	3,326	3,374	101%	164	141	86%
Texas RE-ERCOT	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC-AB	5,684	455	8%	1,870	1,271	68%	896	481	54%	261	222	85%
WECC-Basin	5,959	360	6%	3,773	2,605	69%	884	386	44%	655	557	85%
WECC-BC*	753	60	8%	17	12	71%	1,871	888	47%	-	-	0%
WECC-Cal	7,985	907	11%	27,495	14,278	52%	1,120	628	56%	16,711	14,204	85%
WECC-Mexico	296	3	1%	350	35	10%	-	-	0%	-	-	0%
WECC-NW*	9,941	1,016	10%	1,729	1,051	61%	14,086	8,303	59%	547	461	84%
WECC-RM	5,684	1,034	18%	2,920	1,551	53%	117	61	52%	342	291	85%
WECC-SW	4,848	1,473	30%	11,112	4,868	44%	376	270	72%	3,691	3,137	85%
EASTERN INTERCONNECTION	94,474	21,180	22%	78,714	46,528	59%	18,892	15,435	82%	7,805	7,220	92%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC INTERCONNECTION[23]	41,150	5,308	13%	49,266	25,670	52%	19,350	11,017	57%	22,207	18,872	85%
All INTERCONNECTIONS	**181,153**	**36,673**	**20%**	**168,736**	**101,946**	**60%**	**38,822**	**26,899**	**69%**	**52,442**	**47,005**	**90%**

*On peak contributions from conventional hydro are not represented in this table, and in certain areas those contributions are significant.

[23] Some areas in the Western Interconnection re-categorized their hydro resources for the 2026 SRA from run-of-river hydro to conventional hydro

Review of 2025 Capacity and Energy Performance

The summer of 2025 was the 12th hottest on record for the contiguous United States[24] during the meteorological summer period (June–August) and the 11th warmest summer in Canada.[25] Cooler-than-normal temperatures were observed in the eastern U.S., whereas most of Canada experienced slightly above-normal temperatures. Despite the comparatively temperate 2025 Summer (summer of 2024 was the fourth-hottest on record in both the United States[26] and Canada[27]), U.S. electricity generation reached a record high for the assessment summer period (June – September) at 1,628 TWh[28], topping the prior year's summer electricity generation total of 1,603 TWh. The month of July in the U.S. set a new monthly generation record at 446 TWh. In Canada, the comparatively cooler summer appears to have brought electricity generation down from the 2024 summer high of 192 TWh to the 2025 total of 188 TWh[29]. Actual peak demand exceeded normal demand forecasts across 19 assessment areas and exceeded extreme demand projections from the *2025 SRA* in three assessment areas. Despite a lower average summer temperature in 2025, a widespread heatwave[30] in early summer impacted much of the central and eastern U.S., bringing record-setting temperatures across several hundred counties.

Canada experienced its second-worst wildfire year on record[31] (2023 being the worst) with fires burning an area larger than New Brunswick and Prince Edward Island combined. Saskatchewan and Manitoba comprised nearly half of the total area impacted by the fires. Drought that began in 2021 has also deepened across Canada, resulting in reduced hydroelectric power generation for a third straight year in British Columbia.

Eastern Interconnection–Canada and Québec Interconnection

In Ontario, grid operators utilized demand response resources on 10 different occasions during the summer period,[32] culminating in demand reductions of 316 MW during the time of peak demand (24,862 MW) on June 24, 2025, the single highest peak in 12 years. Other demand-side management programs further reduced peak demand by 1,800 MW, contributing to 7% total reduction in demand stemming from consumer programs.

Québec saw electricity generation of roughly 52 TWh during the summer period,[33] down from 56 TWh for Summer 2024 amid relatively cooler temperatures and a year beset by low runoff levels that have persisted since 2023.[34] The Maritimes saw a slight increase in electricity generation to 5.8 TWh for Summer 2025, up from 5.3 TWh the prior summer. Nova Scotia Power realized nearly a 20% reduction in annual 2025 power outages from the year before but still fell short of targets set by the Nova Scotia Energy Board relating to power-outage duration and frequency.

Saskatchewan saw severe storms and large hail in late August that damaged infrastructure, triggering emergency operating conditions and power outages.[35]

[24] Assessing the U.S. Temperature and Precipitation Analysis in August 2025 | News | National Centers for Environmental Information (NCEI)
[25] Climate Trends and Variations Bulletin - summer 2025 - Canada.ca
[26] U.S. sweltered through its 4th-hottest summer on record | National Oceanic and Atmospheric Administration
[27] Climate Trends and Variations Bulletin - Summer 2024 - Canada.ca
[28] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis
[29] Electric power generation, monthly generation by type of electricity
[30] Assessing the U.S. Climate in June 2025 | News | National Centers for Environmental Information (NCEI)
[31] Canada's top 10 weather stories of 2025 - Canada.ca
[32] 2025 Year in Review
[33] Electric power generation, monthly generation by type of electricity
[34] Hydro-Québec - Quarterly Bulletin - Third Quarter 2025
[35] SaskPower crews still working to restore power after weekend outages - WestCentralOnline: West Central Saskatchewan's latest news, sports, weather, community events.

Eastern Interconnection–United States

New York and New England saw region-wide heat waves in June and July. ISO-NE saw peak-hour demand in June exceed its extreme demand projections from the *2024 SRA*, a significant step up from the prior year's summer peak (+7%). Heat and humidity, high demand, and some unexpected generation reductions and outages left the region short of the resources needed to maintain required operating reserves for more than three hours around the evening peak on June 24,[36] though electricity supply was not interrupted. NYISO declared an EEA Level 1 on June 24, June 25, and July 29 due to limited capacity availability,[37] resulting in the deployment of emergency DR programs and other special-case resources. Both the New York and New England ISOs saw peak loads that exceeded their demand projections.

PJM saw their third-highest all-time summer peak[38] of more than 160 GW. This exceeded extreme demand projections for the summer (159 GW). The system operator was able to manage load by calling on customers who were enrolled in financially incentivized DR programs.

MISO declared an EEA Level 1[39] on June 23 to access emergency capacity. At the time of the event, more than 4 GW of generation was trapped in the south due to transmission constraints. MISO was able to dispatch 565 MW of emergency capacity in the Midwest, but only 45% performed. MISO has been engaged in efforts to highlight the need for non-performance penalties. On June 24, when neighboring areas were experiencing peak demand, MISO had to curtail non-firm exports to avoid going into EEA. In late July, MISO experienced a shortage of operating reserves due to errors in forecasting load and renewables. This was one of 24 total instances of operating reserve shortage, double the amount from the previous year.

In SERC, an EEA Level 2 was declared in the Carolinas amid high load conditions and generation resources that were unavailable[40] during the peak of the June heat wave affecting the broader Eastern Interconnection – a precautionary reliability measure to support system operations during peak demand and generation outages. During this event, the affected service territory recorded a new all-time peak demand of 21,931 MW on June 25.

Texas Interconnection–ERCOT

Texas saw a relatively mild summer and above-average rainfall in 2025 with the June–July period ranking as the 43rd hottest out of 131 historical years. But even so, Summer 2025 load levels were comparable to the 2023 Summer load levels when the summer was far hotter.[41] Forced outages of thermal resources outstripped such forced outages from the summer of 2024, prompting a larger discharge of energy storage resources (ESR) some evenings. Texas set a new solar generation record in July at 29.3 GW, and solar contributed just under 17 GW at the hour of peak demand on August 18 (hour ending at 6:00 pm). Wind generation was relatively high at the peak demand hour and also set records in the spring. Energy storage also reached a new discharge record at 7.2 GW on August 20.

Western Interconnection

The Western Interconnection saw summer peak demand decrease slightly from the previous year's summer peak, reaching 163,140 MW in 2025, down from 168,206 MW the prior summer. Operators and RCs were able to maintain the flow of electricity through the summer months.

[36] Summer 2025 recap: Reliability maintained as grid sees highest peak in over a decade - ISO Newswire
[37] NYISO Summer 2025
[38] 2025 in Review: Operations Improvements See PJM Through Record Peaks, Growing Demand | PJM Inside Lines
[39] Microsoft PowerPoint - IMM Quarterly Report, Summer 2025
[40] DOE grants Duke Energy authority to exceed power plant permit limits during extreme heat | Utility Dive
[41] 12 Summer 2025 Operational and Market Review.pptx

Western Interconnection–Canada

Western Canada experienced a heat wave from late August and through early September, breaking daily records in British Columbia and the Yukon and exacerbating the ongoing drought in western Canada. Wildfire activity also increased due to heat and dry conditions. The same period brought generation outages that triggered emergency operations in parts of western Canada.

Western Interconnection–United States

The western United States overall navigated last summer with the BPS experiencing relatively few emergency events, and demand in western assessment areas never reached or exceeded the projections for extreme demand from the *2025 SRA*. Variable resources performed as expected with the exception of California seeing much less solar generation than anticipated, 65% less solar than was projected ahead of the prior year's assessment. California's lower-than-expected solar did not result in energy shortfalls.

In Mexico, generation losses in late August triggered Level 3 EEAs, but the overall number of Level 3 EEAs was down year-on-year and on par with the number of Level 3 EEAs triggered in 2023 for the same seasonal period.

Despite the moderation in summer heat when compared to 2024, certain Rocky Mountain states saw record temperatures with Utah and Nevada recording their warmest years on record. The Rocky Mountain region saw peak demand surpass the projected normal demand conditions but remained under extreme demand projections.

2025 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	121.6	116.3 121.6	1,105	6,039	12,323	9,123	8,856
MRO-Manitoba Hydro	3.5	3.4 3.6	0	48	0	0	252
MRO-SaskPower	3.6	3.6 3.8	232	310	26	9	0
MRO-SPP	54.5	54.8 57.5	8,130	5,556	810	492	4,370
NPCC-Maritimes	3.6	3.3 3.5	151	314	69	0	33
NPCC-New England	26.6	24.7 26.4	566	142	180	1,412	1,963
NPCC-New York	32	30.0 31.7	1,256	446	164	243	1,372
NPCC-Ontario	24.9	21.0 24.5	607	742	39	66	1,532
NPCC-Québec	23.0	22.3 23.3	790	885	0	0	5,029
PJM	160.7	146.2 158.7	4,515	1,855	7,730	6,244	15,945
SERC-C	43.2	41.9 45.7	84	370	714	1,053	701
SERC-E	44.8	42.5 45.7	0	0	3,200	5,022	2,407
SERC-FP	54.6	49.8 50.8	0	0	8,035	5,749	1,599
SERC-SE	46.4	45.7 55.9	0	0	3,366	7,728	1,380
TRE-ERCOT	83.7	85.2[5] 91.3[5]	14,509	9,396	16,961	22,962	11,095
WECC-AB	12.5	12.2 12.7	2,870	796	32	1,480	**
WECC-BC	9.8	9.3 10.0	293	149	4.8	0	**
WECC-CA	54	54.1 64.3	1,744	1,207	5,064	14,756	1,063

2025 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
WECC-MX	3.5	3.8 4.1	2.5	50	296	227	**
WECC-NW	29.8	29.1 32.7	1,054	3,107	1,398	666	1,825
WECC-RM	13.4	13.8 15.0	2,313	1,359	1,571	1,669	1,954
WECC-Basin	13.8	13.6 15.0	931	911	2,660	2,231	0
WECC-SW	36.9	35.1 39.0	1,230	1,091	4,472	4,293	2,323
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from the assessment areas.
[2] See NERC *2025 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2025 SRA*.
[4] Values from NERC Generator Availability Data System for the 2025 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2025 SRA*.
[5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (3.2 GW) to the demand scenarios found on p. 30 of the 2025 SRA.
**Data unavailable - Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

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

Exhibit 3-06:
Grid Strategies Analysis of NERC 2026 Summer Reliability Assessment



Review of NERC's 2026 Summer Reliability Assessment

Dr. Adria Brooks

July 2026 (updated 7/10/26)

Prepared for Earthjustice, Natural Resource Defense Council, Sierra Club, and Environmental Defense Fund

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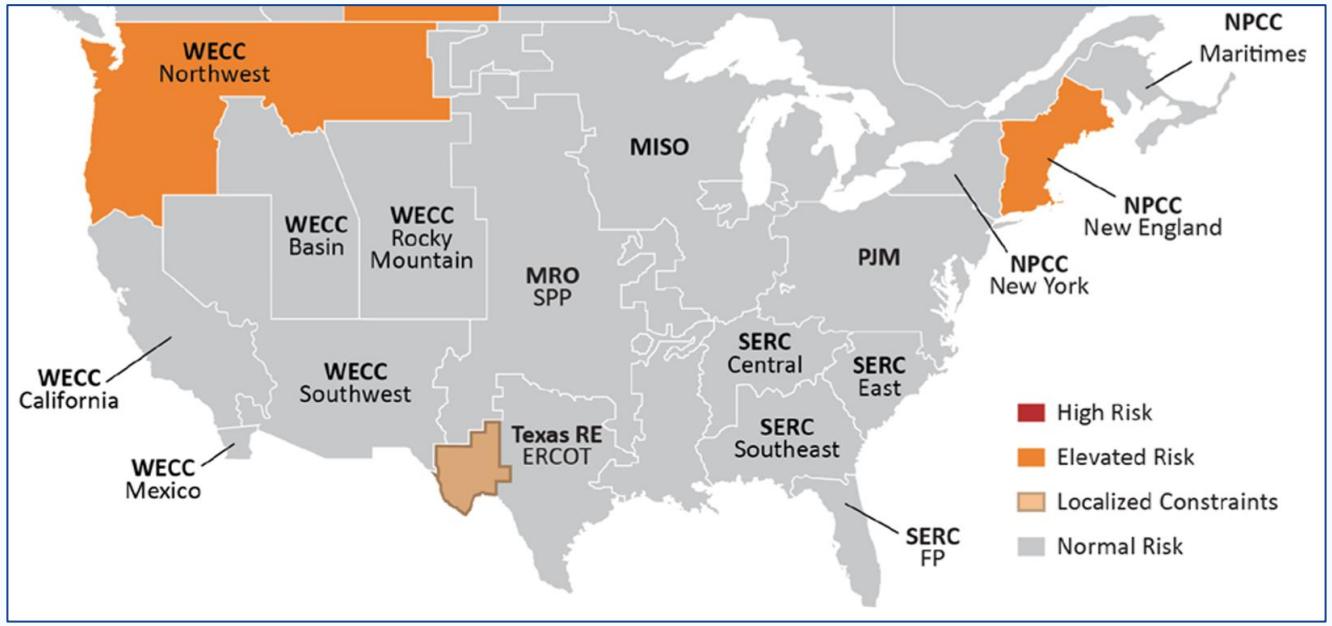
1. Executive Summary
2. Trends in NERC Assessment Forecasts
3. Peak Demand and Certain Resources
4. Typical Conditions and Extreme Events
5. New England
6. Northwest
7. Conclusions

Executive Summary

The NERC Summer Reliability Assessments provide a summary of the potential reliability concerns for the upcoming summer. They help operators understand what existing operational tools may be needed to meet near-term demand.

NERC's Summer Reliability Assessments (SRA) evaluate potential reliability concerns for the upcoming summer. They provide practitioners with an understanding of what existing operational tools and external assistance may be needed to serve demand.

The SRAs consider two different load scenarios in determining reliability concerns. Normal load is the median (50%) of potential load conditions. Extreme load represents high load conditions that are less likely to occur (10%) of potential demand scenarios. Extreme load conditions represent once-in-a-decade events and are used to characterize the worst-case scenarios, not expected conditions for the coming summer.



In its 2026 SRA, NERC identified two U.S. regions—New England and Northwest—at "elevated risk." Using industry-reported data, NERC finds the regions are resource adequate under expected seasonal conditions and may need to rely on operational mitigation procedures and non-firm imports—which are available to operators though not considered in resource adequacy calculations—to meet the once-in-a-decade extreme load conditions. However, other data suggests that the regions are also resource adequate under extreme conditions.

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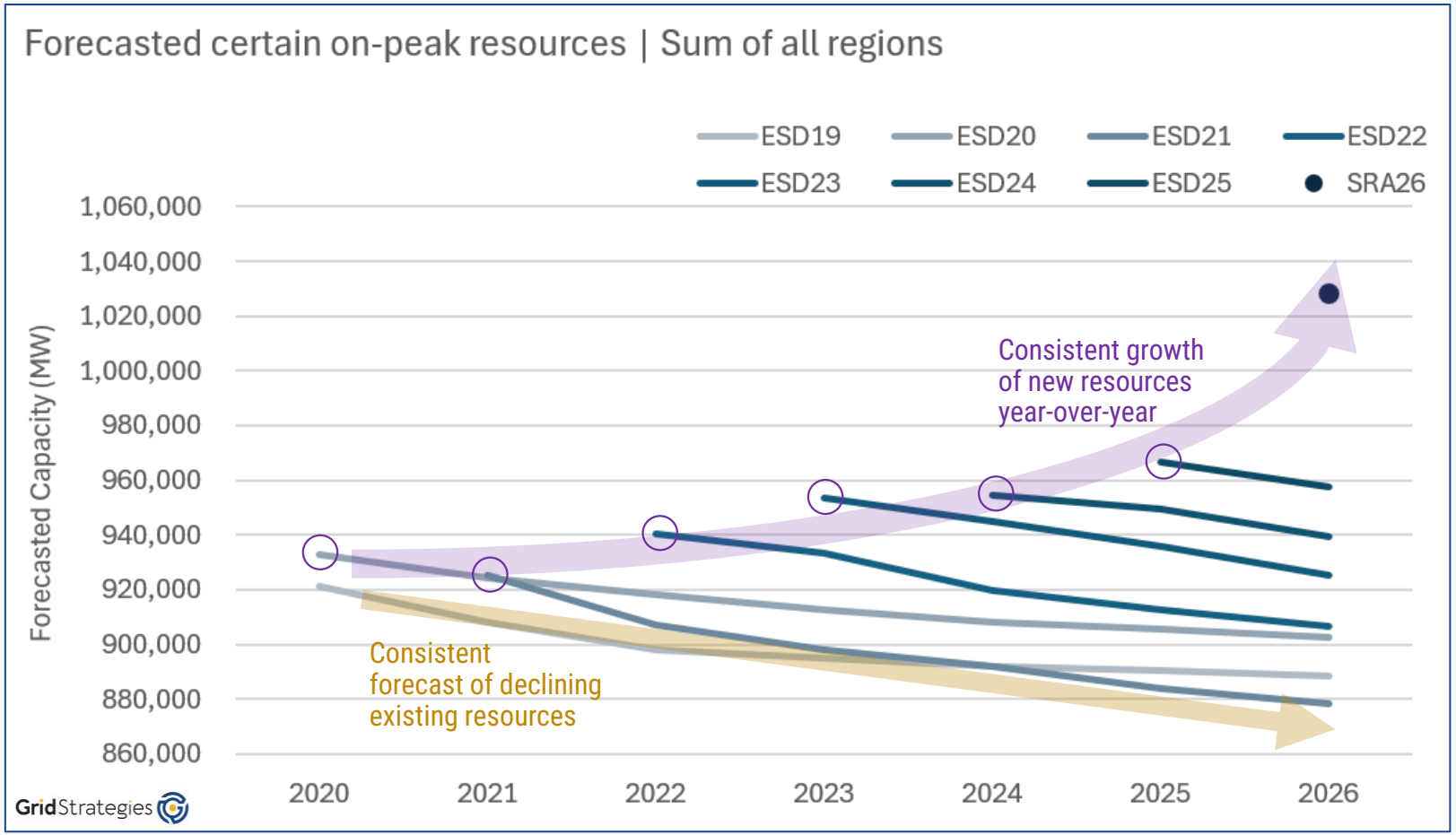
IMAGE SOURCE | NERC "Summer Reliability Assessment (SRA)" (2026)

Main Takeaway: Resource projections reported to NERC consistently underestimate the growth of new renewable resources, and projections of "certain" resources, by definition, omit all likely-to-connect new resources. Use of this information alone paints an inaccurate picture of being unable to meet growing demand in future years.

Regional system planners report resource and demand projections to NERC. These industry projections of future resource capacity consistently underestimate the rapid growth of new additions while accurately capturing resource retirements. This combination paints an inaccurate picture of declining resource availability in a time of growing demand. By excluding likely-to-connect new resources, it appears that future generation will fall short of grid needs.

State regulators and wholesale power market price signals ensure the orderly replacement of retiring resources and correct any imbalances in expected electricity demand and generating supply (OMS).

Note: This takeaway and graph are more thoroughly explained on slides 9-14.



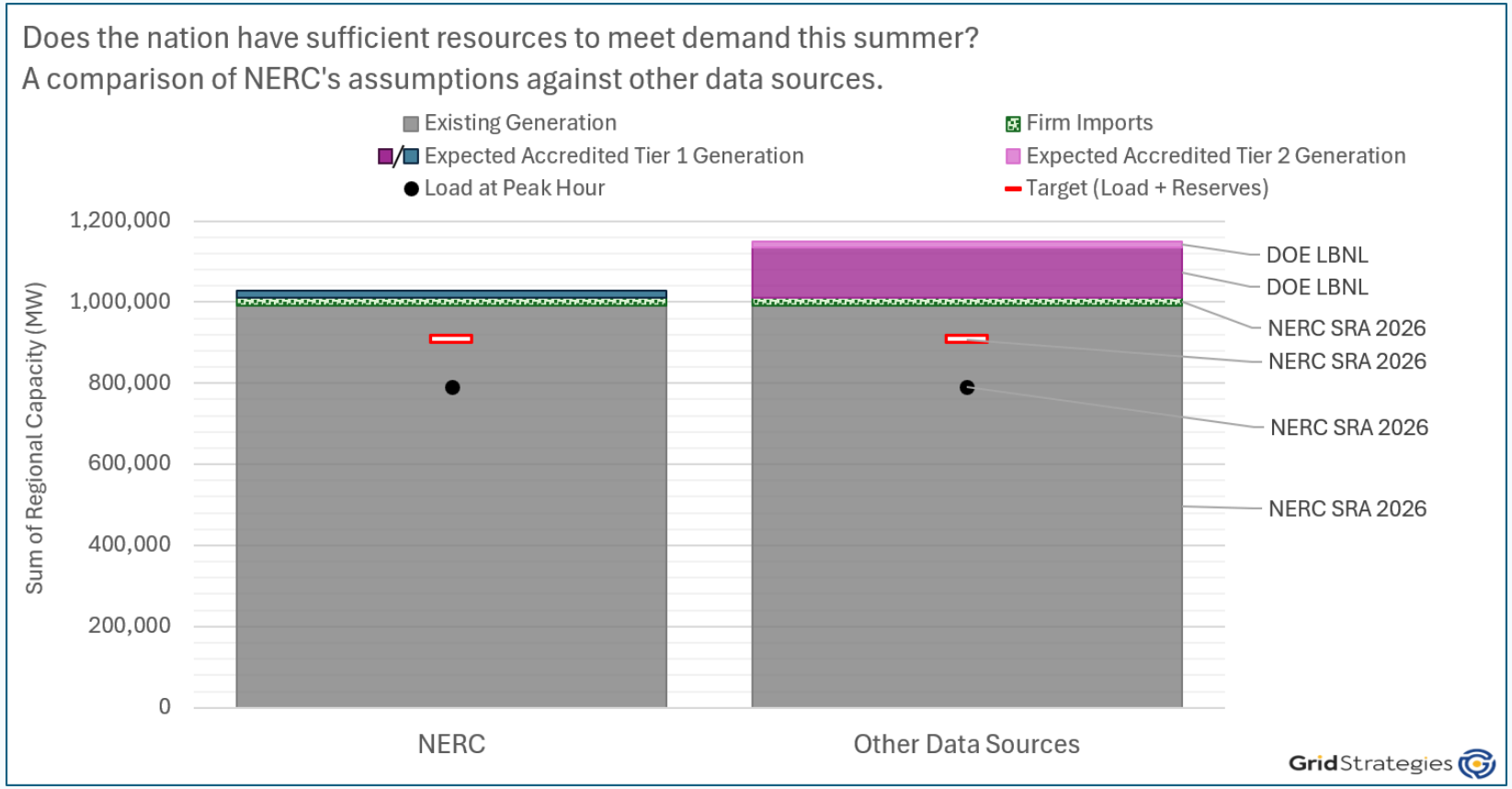
DATA SOURCE | NERC "Electricity Supply and Demand Database (ES&D)" (2019) – (2025); NERC "SRA" (2026); Organization of MISO States (OMS) "2026 OMS-MISO Survey Results" (2026)

Main takeaway: 2026 summer resource availability exceeds NERC forecasts in all regions after accounting for likely-to-connect resources.

Given the consistent underestimate of new generation in industry-reported data, we supplement NERC's analysis with data supplied by other reputable federal sources.

The expected future resource availability is from a national laboratory repository of interconnection queue data across the United States. This queue data is adjusted downward to account for historic regional, resource type, queue study phase, interconnection trends to ensure that we are not overcounting.

This comprehensive picture of likely-to-connect resources shows that all regions have between 5% - 93% *more* reserves than their target reserve margin. When summed together (as shown in graph), resources exceed expected peak demand by 45%.



Note: This takeaway and graph are more thoroughly explained on slides 15-19.

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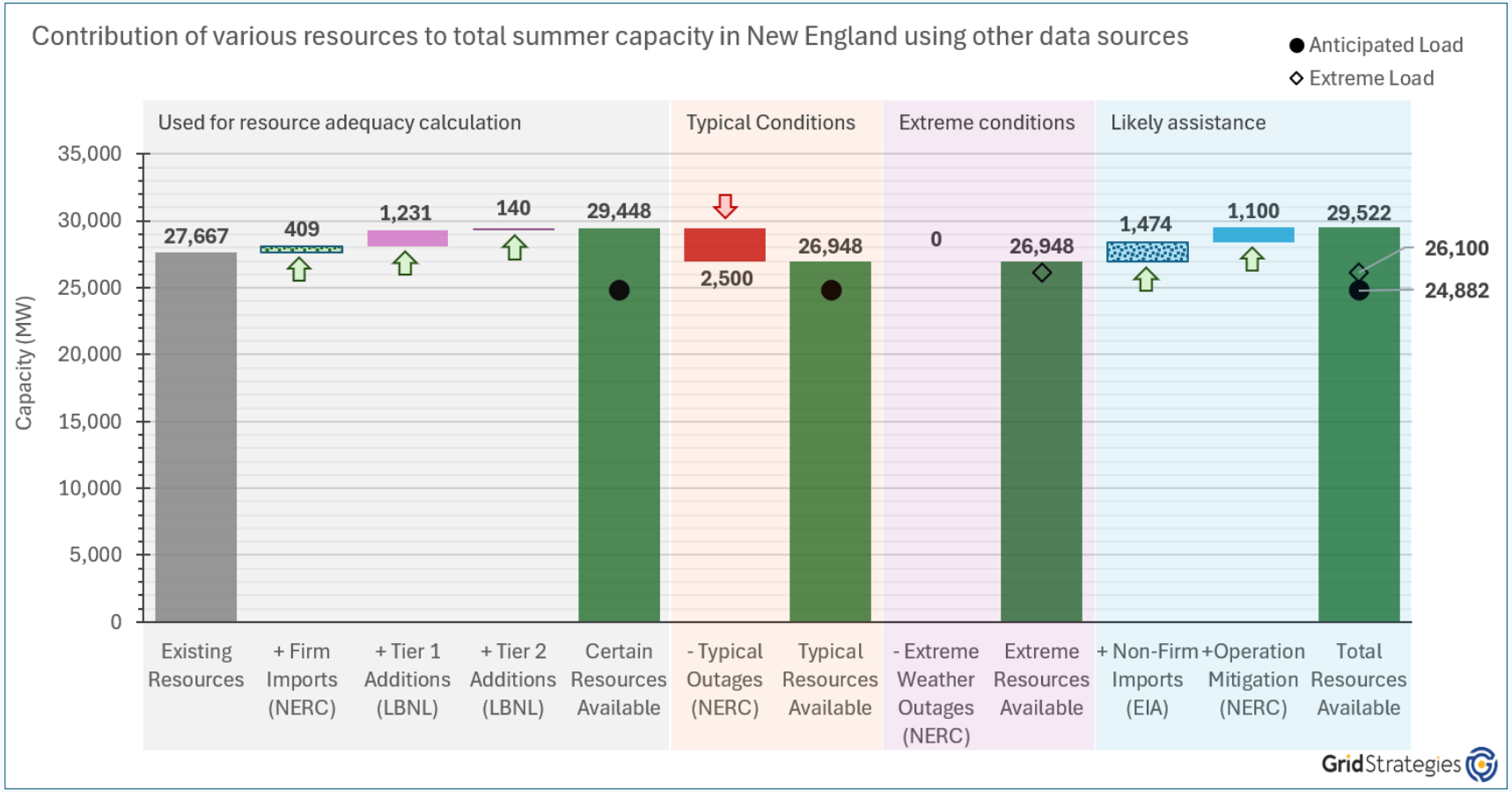
DATA SOURCE | NERC "SRA" (2026); Rand, J. et al. "Interconnection Queue Dataset & Summarized Data Files, through 2024" (2025)

Main takeaway: New England has sufficient resources to meet summer 2026 load. Operational mitigation procedures and increased import capability further strengthen the region's ability to serve load reliably.

NERC data show that New England has enough resource capability to serve its load under both typical and extreme conditions, so long as operational mitigation strategies are employed as designed. This headroom to serve load increases when considering likely-to-connect resources from the interconnection queues, even without operational mitigation. Finally, additional non-firm imports from Canada are available to serve load.

Taken together, these resources provide New England with a comfortable reserve margin above its target to serve load this summer.

Note: This takeaway and graph are more thoroughly explained on slides 24-29.



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DATA SOURCE | NERC "SRA" (2026); Rand, J. et al. "Interconnection Queue Dataset & Summarized Data Files, through 2024" (2025); EIA "Form 930 Interchange Data" (2022)–(2026)

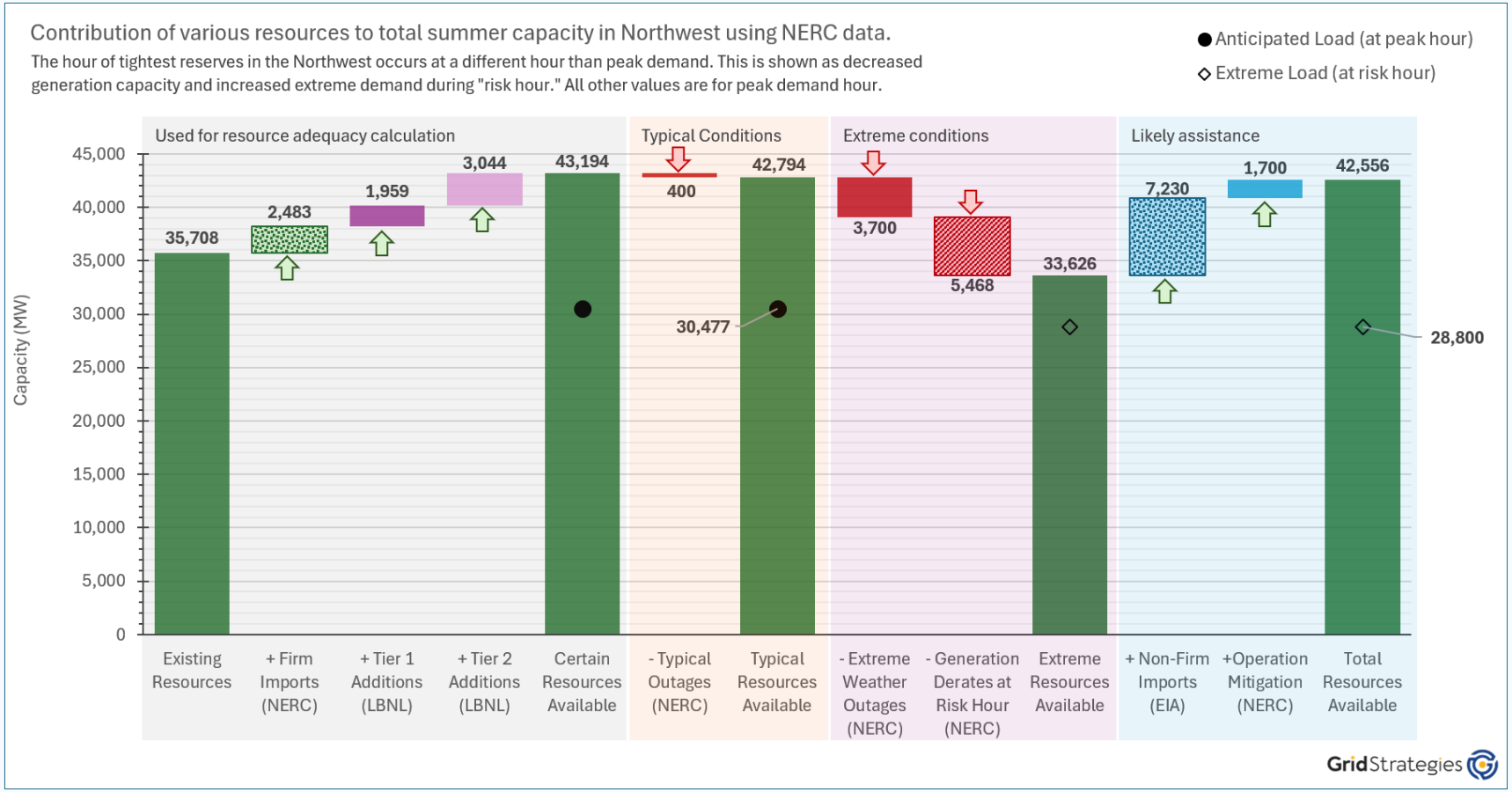
Main takeaway: The Northwest has sufficient resources to meet summer 2026 load. The combination of operational mitigation, high import assistance from neighbors, and El Niño weather conditions further reinforce the region's capacity reserves.

NERC data show that the Northwest has enough resource capability to serve its load under both typical and extreme conditions. This is true even in circumstances with high generator outages (i.e., lower supply than typical) and high load (i.e., higher demand than typical).

This headroom increases when considering likely-to-connect resources from the interconnection queues. In the event of extreme events that stress the grid, significant additional non-firm imports from neighboring regions would likely be available to serve load. Finally, additional rainfall from this summer's El Niño is expected to strengthen hydroelectric reserves in the Northwest.

Taken together, the Northwest has a comfortable reserve margin above its target to serve load this summer.

Note: This takeaway and graph are more thoroughly explained on slides 30-35.



Year-Over-Year Trends in NERC Assessment Forecasts

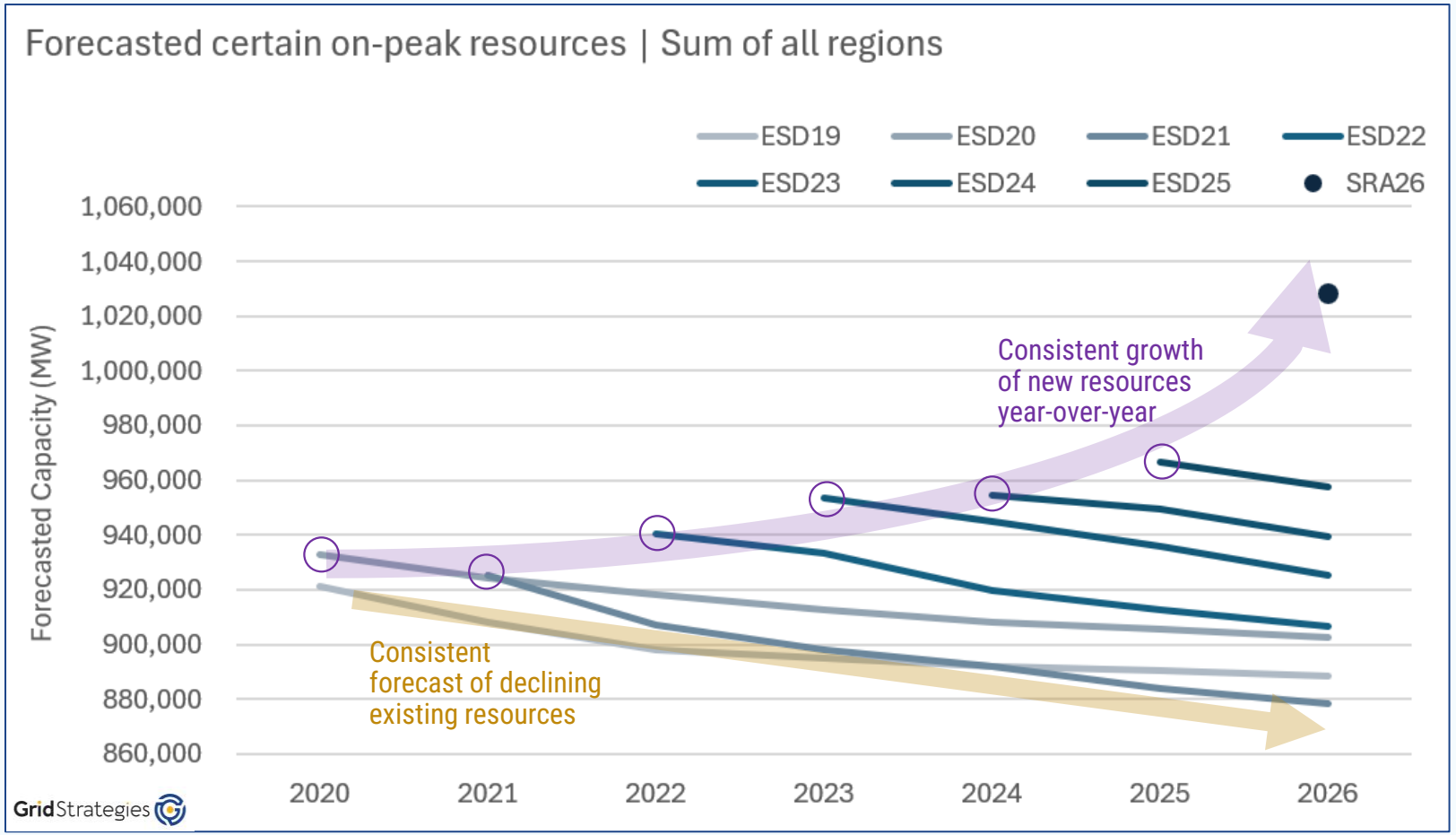
New generation resources added to the grid are omitted from NERC's published "certain" resource availability year after year.

Each year NERC compiles regional planners' future projections for resource capacity added to or removed from the grid. NERC's reliability assessments assess resource adequacy using projected *certain** generation capability in future years.

NERC assessments have shown the same trend for the last 7 years in a row: future "certain" capacity is always projected to decline, while each subsequent year's assessment consistently shows an increase in available capacity.

By only looking at trends in "certain" resources, year-over-year growth in new resources will be missed.

*NERC considers any in-service generation and confirmed resource retirements to be "certain." NERC does not re-categorize any amount of Tier 1 or Tier 2 resources working their way through the interconnection queues as "certain" in future years, thereby omitting generation growth.



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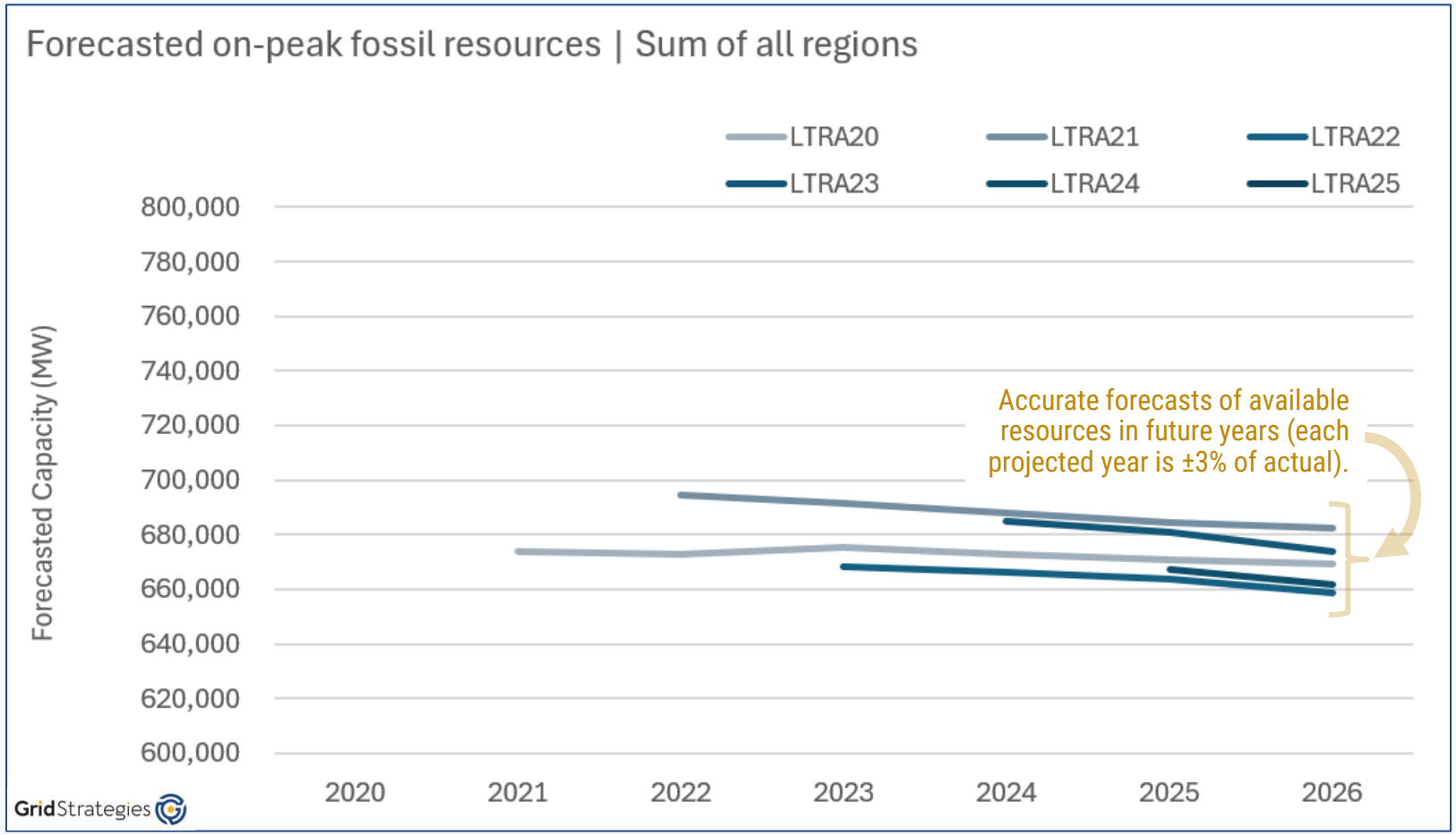
DATA SOURCE | NERC "Electricity Supply and Demand Database (ES&D)" (2019) – (2025); NERC "SRA" (2026)

NERC assessments accurately capture resource retirements.

"Certain" resources do capture generation retirements, which dominate the trends in declining future resources shown on the previous slide. Industry projections of future fossil fuel resources (coal, petroleum, and natural gas) have been roughly accurate to actualized plant availability: forecasts of future fossil fuel resource capacity are consistently within ±20 GW (±3%) of the capacity that is realized in that year.

Since the decline of fossil fuel resources are accurately captured in the reliability assessments, the persistent under-estimate of available future resources is instead due to the omission of new generation being added to the grid.

Note: The y-axis has changed from the previous chart, but the range of the axis (200,000 MW) and gridline intervals (20,000 MW) are the same for comparison.



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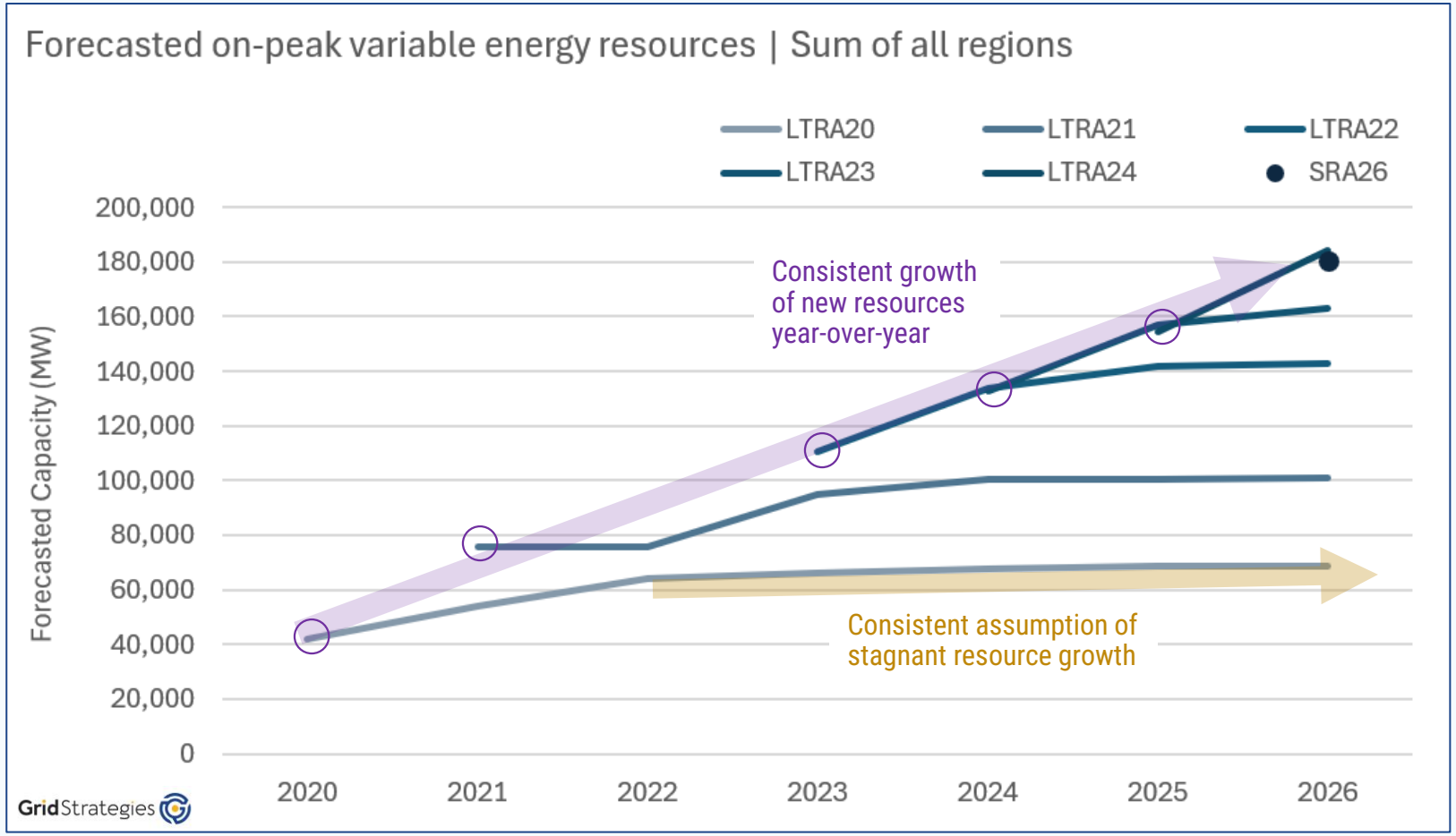
DATA SOURCE | NERC "Long Term Reliability Assessments (LTRA)" (2020) – (2025); NERC "SRA" (2026)

Missing from the future resource capacity forecasts are new generation additions. NERC reliability assessments consistently underestimate the pace of new generation added to the grid.

NERC assessments consistently underestimate the growth of new resources, particularly for solar, wind, and batteries. Forecasts show growth in these resources for a couple of years, but then stagnation. This is likely due to NERC's practice of only considering existing and Tier 1 resources as "anticipated" resources rather than including a portion of Tier 2 resources that are likely-to-connect. Tier 2 resources are in the interconnection queue but have not yet signed an interconnection agreement.

As a result, NERC assessments fail to capture the rapid growth of renewable energy and battery resources. A look at the resources which have been put in service each year (first data point of each line to right) shows that **new resource additions outpace both expectations and resource retirements.**

Note: The y-axis has changed from the previous chart, but the range of the axis (200,000 MW) and gridline intervals (20,000 MW) are the same for comparison.



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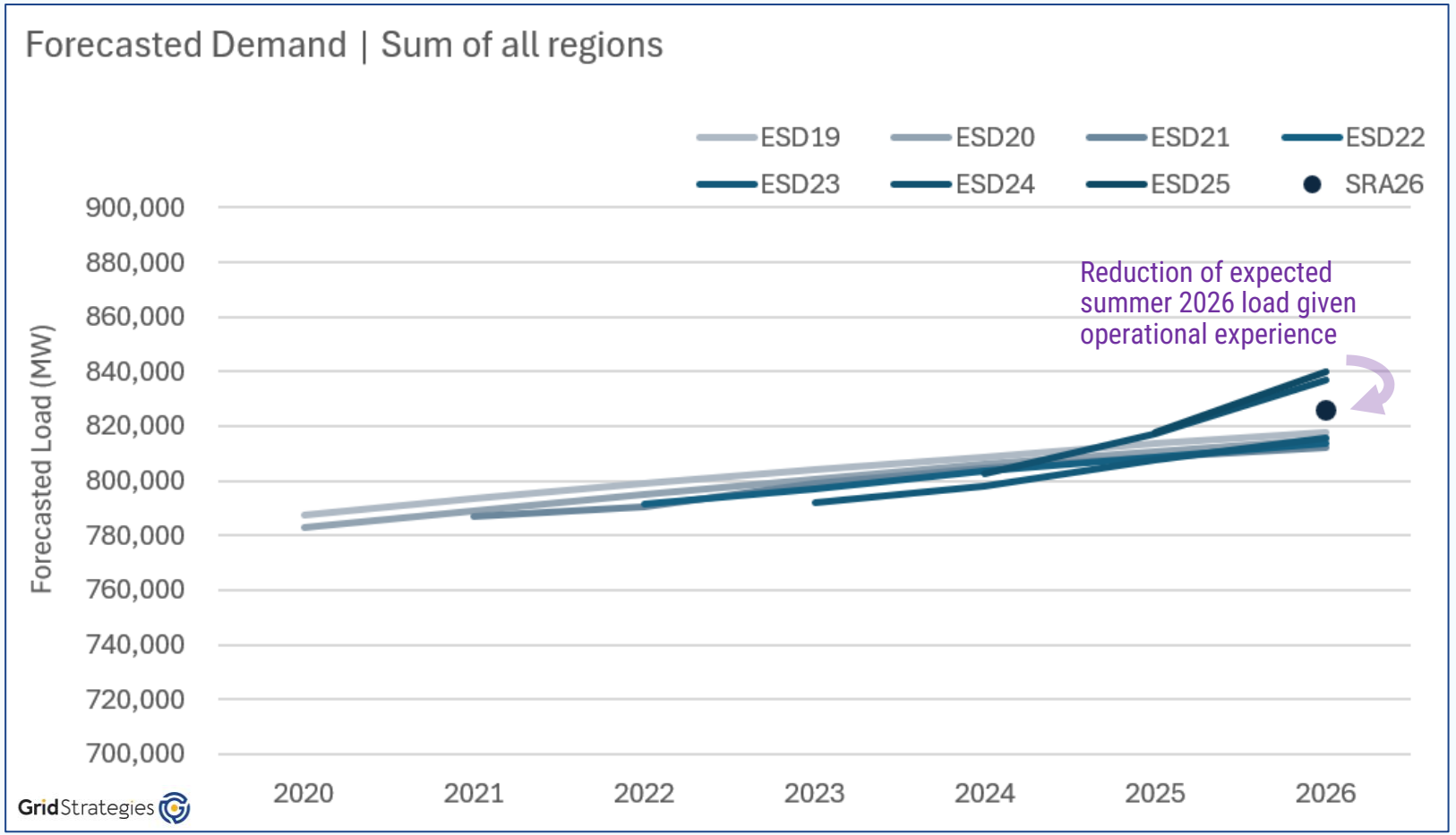
DATA SOURCE | NERC " LTRA" (2020) – (2025); NERC "SRA" (2026)

Demand growth is well-captured in NERC assessments.

NERC assessments have done a good job of estimating future load growth. There was a major change in the load growth forecasts reported to NERC in 2024 given the rise in high-electricity use industries, notably data centers.

The combination of expected milder summer 2026 weather conditions, slower pace of large load interconnections, and the operational use of data center curtailment—as highlighted by NERC in the 2026 SRA—resulted in a reduction of the expected peak load for the upcoming summer. This alleviates stress on the grid.

Note: The y-axis has changed from the previous chart, but the range of the axis (200,000 MW) and gridline intervals (20,000 MW) are the same for comparison.



GridStrategies

DATA SOURCE | NERC "Electricity Supply and Demand Database (ES&D)" (2019) – (2025); NERC "SRA" (2026)

Main Takeaway

By omitting continued growth in new generation additions—notably underestimating the rapid growth of solar, wind, and batteries—while accurately capturing resource retirements, industry projections of resource availability underestimate future anticipated resource capacity.

This paints an inaccurate picture of declining resource availability in a time of growing demand.

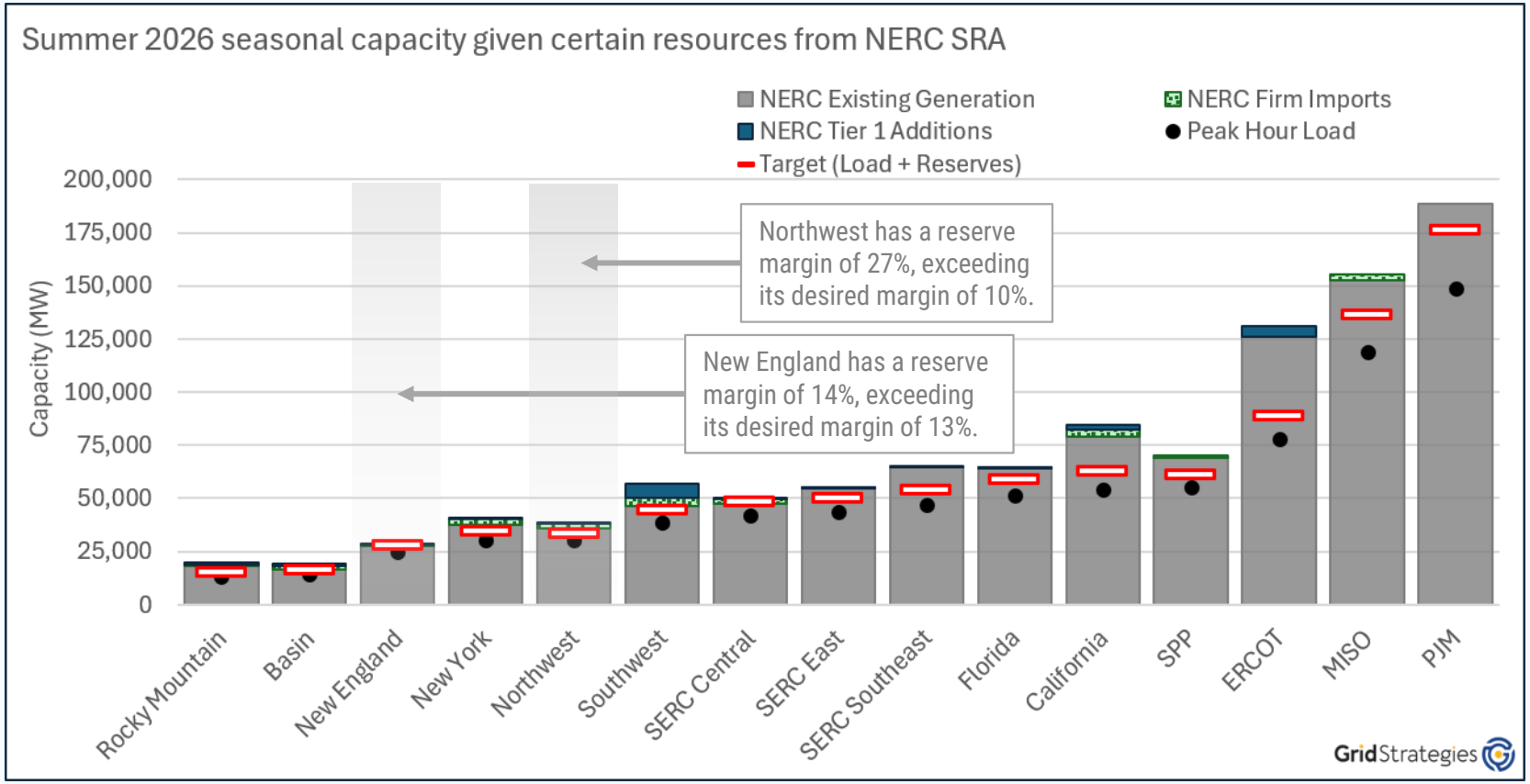
Summer 2026 Resource Adequacy Given Peak Demand and Certain Resources

NERC finds that all regions have sufficient generation capacity to exceed their target reserve margin at the highest risk hour.

NERC data shows that all regions have sufficient resources to meet their expected summer 2026 demand.

To be resource adequate, a region must have enough **existing**, **future**, and **imported** generation capacity to meet their combined load and reserve margins (labeled as "**target**" in the figures). The target is calculated using peak load. NERC only considers Tier 1 resources—those generators with signed interconnection agreements—toward "certain" future resource capacity, the implications of which are discussed on the next slide.

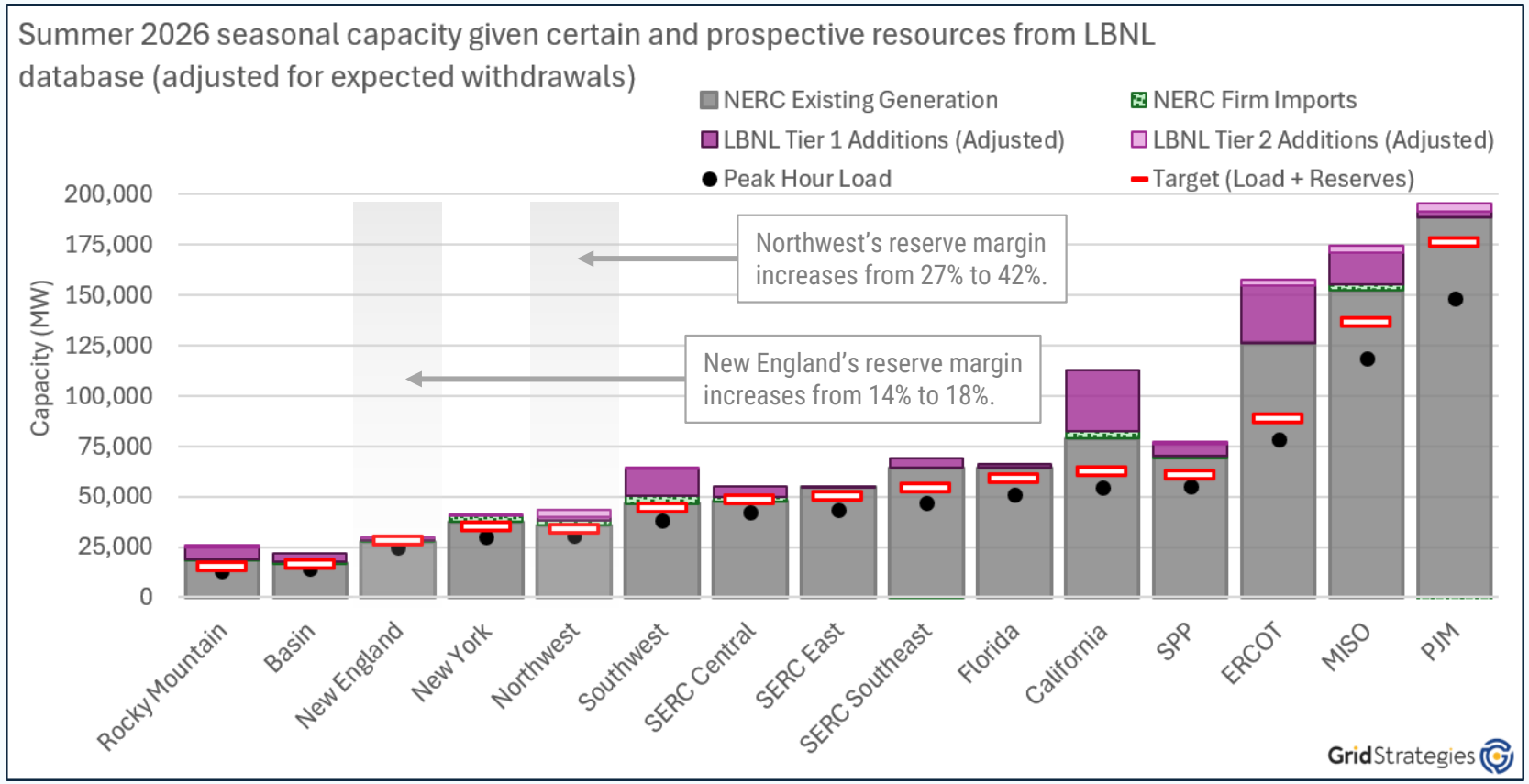
NERC identifies two U.S. regions—New England and Northwest—as having elevated risk of unserved load in summer 2026. These potential shortfalls are modeled despite having adequate resources available at peak load hour. We will explore these two regions in more detail in subsequent slides.



Using future capacity data informed by historic trends from LBNL, the amount of excess capacity at peak demand hour in each region further increases.

The U.S. Department of Energy (DOE)'s Lawrence Berkley National Laboratory (LBNL) tracks interconnection queue data across all regions and is a reputable source of high-quality data. The LBNL data suggests more accredited **Tier 1** resource capacity is available nationwide than is recorded by NERC, though regional allocations vary. LBNL data also includes **Tier 2** capacity—generation progressing through the interconnection queues but without a signed agreement.

Rather than count all potential Tier 1 and omit all Tier 2 resources (as done by NERC), we apply historic regional- and queue phase-specific withdrawal rates to both resource classes from the LBNL data to estimate how much new capacity will likely come online by summer 2026.* We also cut the Tier 2 capacity in half to further discount resources likely-to-connect by summer instead of year end. This paints a more accurate picture of what capacity can be expected.



*All LBNL generation capacity used in this analysis has been discounted using regional, seasonal, and resource-specific accreditation methods, to show the expected generation capacity during peak load. See Brooks, Goggin, Wilson (2026) for more information.

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DATA SOURCE | NERC "SRA" (2026); Rand, J. et al. "Interconnection Queue Dataset & Summarized Data Files, through 2024" (2025)

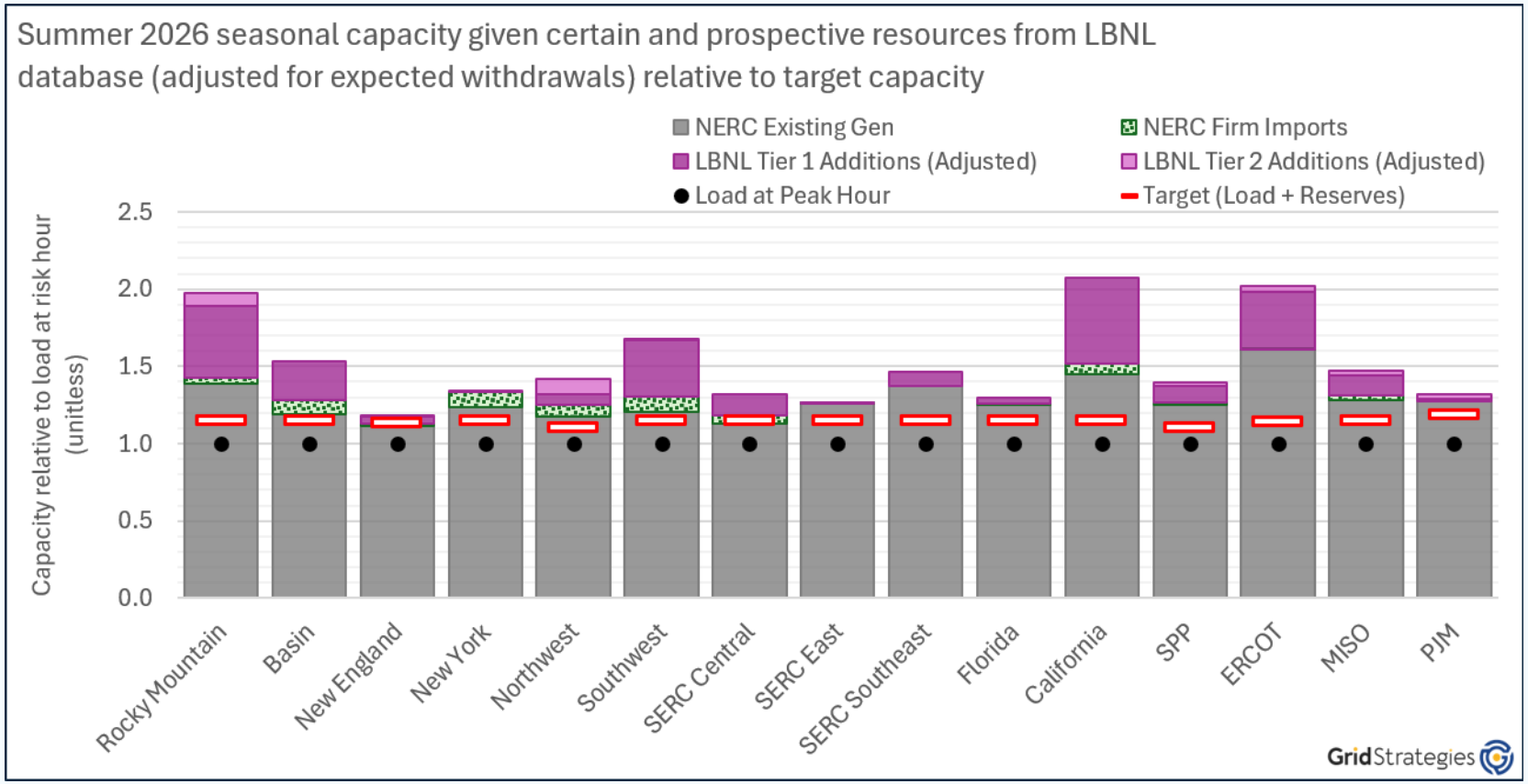
Using future capacity data informed by historic trends from LBNL, the amount of excess capacity at peak demand hour in each region further increases.

This view provides the same information as on the preceding slide, but with a better look at headroom above target resource capacity in each region.

This chart normalizes all regional resource capacity by the peak demand. In this view, peak load is set to 1 across all regions. The sum of stacked resources above the red line indicates extra available capacity above the target amount.

At the low end, New England has 5% *more* headroom than its target margin of 13% while, at the high end, California has 93% *more* headroom than its target reserve margin of 15%.

Consideration of likely-to-connect resources shows that all regions surpass their desired target capacity by comfortable margins.



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DATA SOURCE | NERC "SRA" (2026); Rand, J. et al. "Interconnection Queue Dataset & Summarized Data Files, through 2024" (2025)

Main Takeaway

We repeated NERC's resource adequacy analysis using expected future resource capacity from a reputable national laboratory database. To be conservative, we adjusted those capacities downward to account for historic regional, resource type, queue study phase, and interconnection trends.

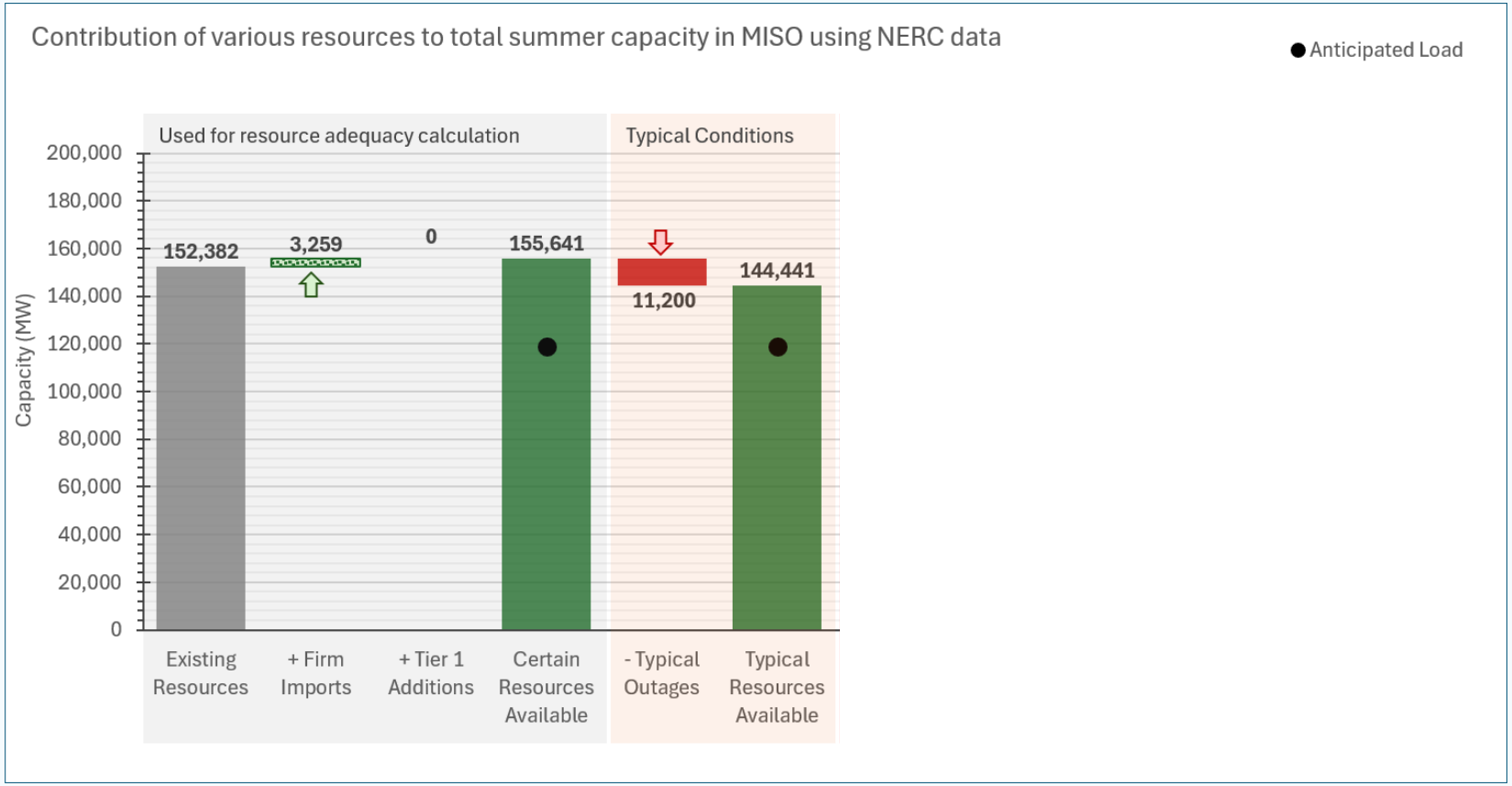
This comprehensive picture of likely-to-connect resources shows that all regions have between 5% - 93% *more* reserves than their target reserve margin.

Summer 2026 Resource Adequacy Given Typical Conditions and Extreme Events

NERC calculates anticipated reserve margin based on certain resources and peak demand. To get a more complete picture, NERC also considers typical outages and other potentially available resources to the system.

As demonstrated on the previous slides, typical resource adequacy evaluations only consider the amount of certain generation capacity against load at peak demand hour. This is highlighted to the right for an example region (MISO) as a waterfall chart. The combination of **existing** resources, **firm import** additions, and **tier 1 capacity** additions make up the "**certain**" resources, which should exceed **peak demand** (●).

But the system is rarely operating with only these resources available to it. To better demonstrate typical operating conditions, NERC also assesses a reduction in expected capacity from **typical generation outages**. The combined impact of these changes should still leave enough resource capacity to meet expected peak demand.



Extreme events further stress system adequacy. The impacts of extreme events can be tested in much the same way as typical conditions.

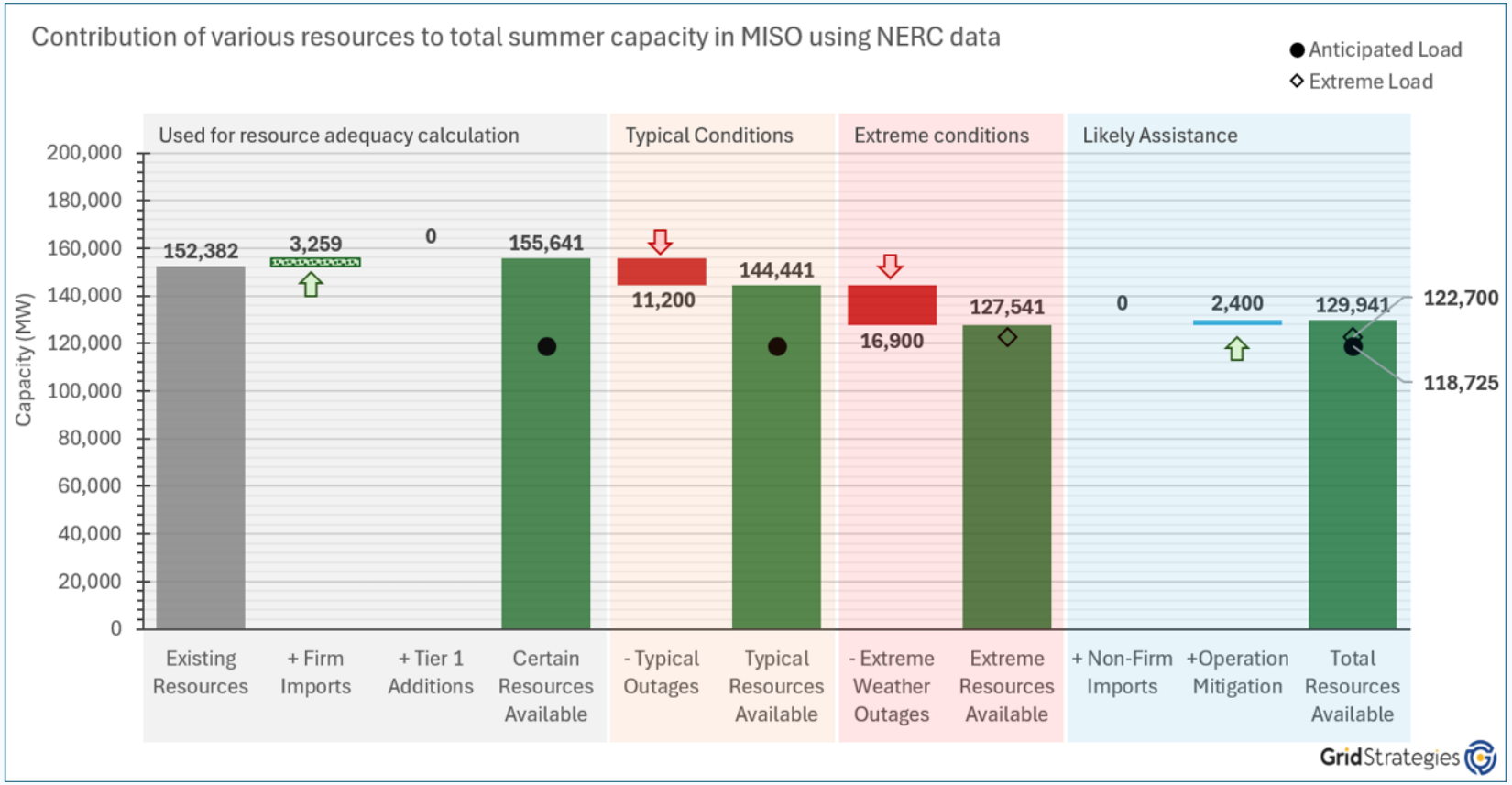
Extreme weather events stress the system in two ways: they further reduce generation availability (e.g., fuel supply freezes during a cold snap) and increased electricity demand (e.g., increased residential heating load during the same cold snap).

These impacts can be modeled as a reduction in capacity from **extreme weather outages** and as an increase in **demand** (◊). Extreme demand modeled here represents a once-in-a-decade event.

To help combat these stress impacts, operators get assistance from **non-firm imports** and **operational mitigation strategies**—such as curtailment of interruptible load and voltage reduction—to increase capacity. Though operational mitigation is only used during times of grid stress, these are common tools available to all system operators in grid stress events.

The combination of these resources should provide enough capacity to meet extreme load. The primary reason grid planners maintain reserve margins above expected peak demand is to ensure reliability even with interannual variability in demand and generation.

In this example, MISO has sufficient resources to meet both load conditions for summer 2026. This same analysis is performed for all regions to evaluate summer reliability risk.



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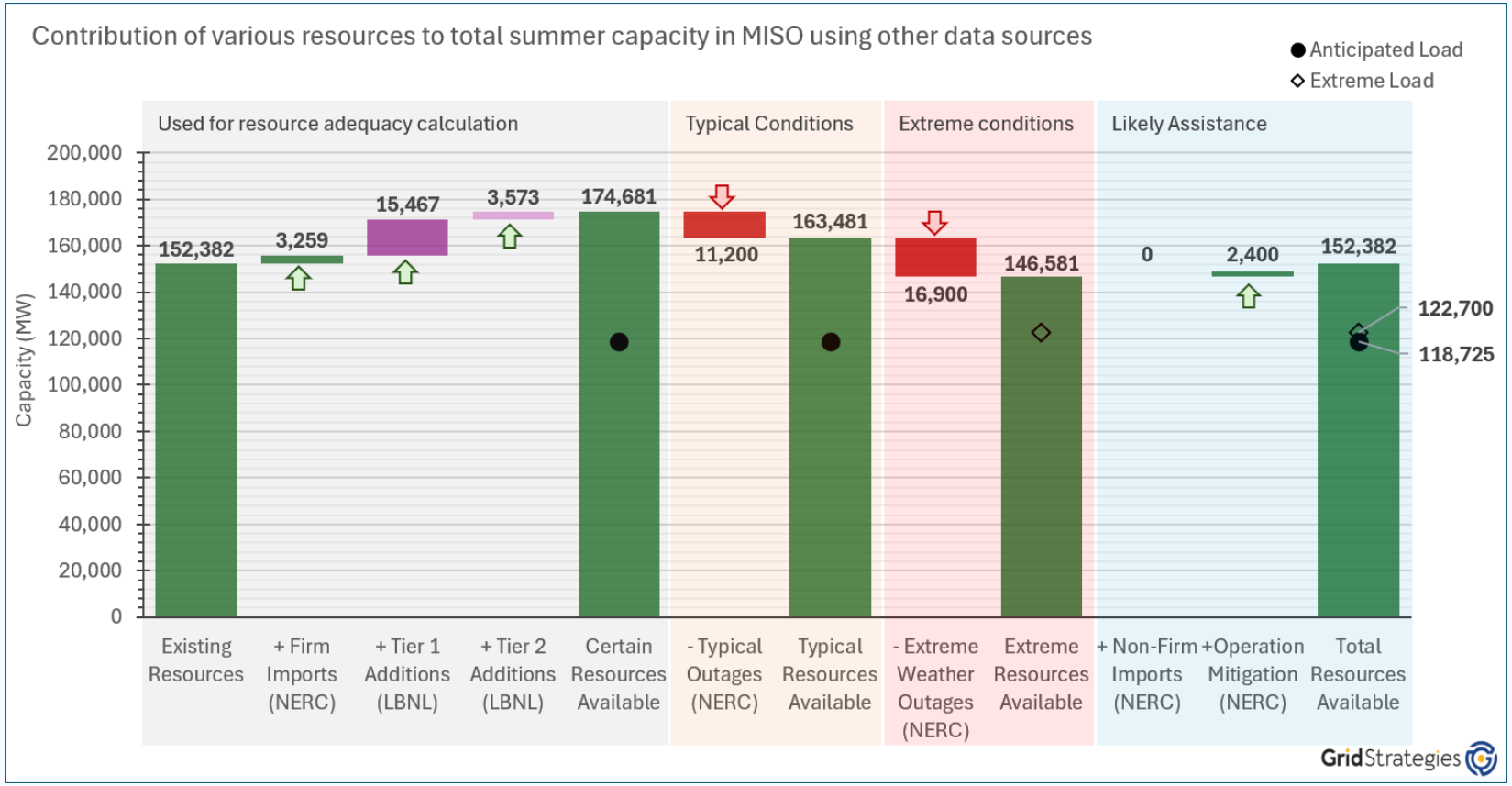
DATA SOURCE | NERC " SRA" (2026)

Extreme events further stress system adequacy. The impacts of extreme events can be tested in much the same way as typical conditions.

In order to better capture new generation resources that are consistently missed in the resource projections reported to NERC, we combine likely-to-connect resources from the LBNL interconnection queue data. Most data in the chart to the right remains unchanged from the resource and outage projections used by NERC, except for the **Tier 1** and **Tier 2** resource capacity data from LBNL.

Both Tier resource additions are derated using historic regional- and queue phase-specific withdrawal rates. We also cut Tier 2 capacity in half to only account for those resources that would be available by summer instead of year-end.

The available capacity in MISO increases from just under 130GW to over 152GW given this more comprehensive picture of summer resource availability.



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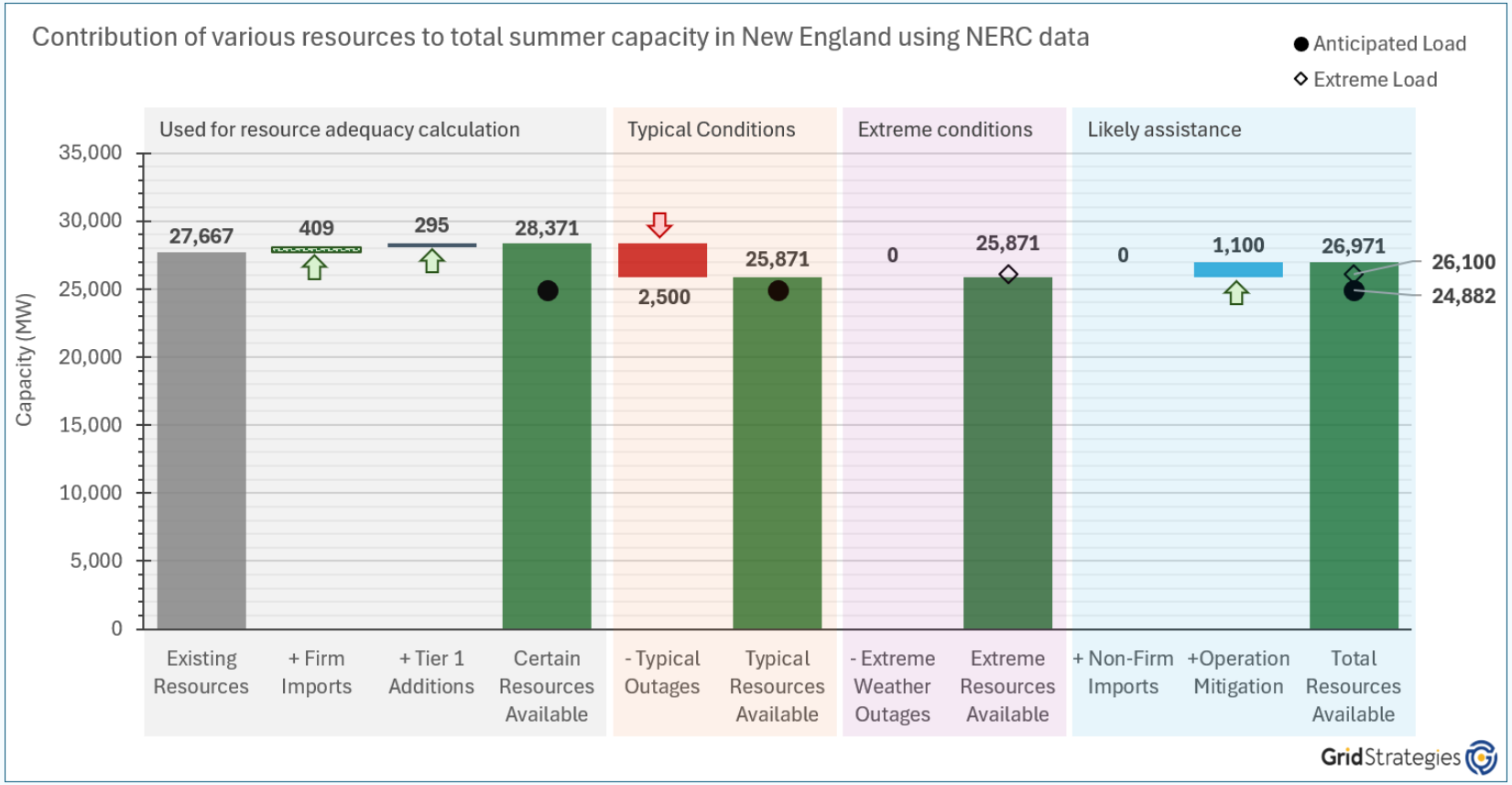
DATA SOURCE | NERC "SRA" (2026); Rand, J. et al. "Interconnection Queue Dataset & Summarized Data Files, through 2024" (2025)

Summer 2026 System Adequacy in New England

System adequacy analysis using industry-reported data shows New England has sufficient resources to meet load under both typical and extreme weather conditions, so long as operational mitigation is employed.

NERC identified New England as at elevated risk for summer 2026, namely during extreme load conditions in June and July. NERC assigned this risk designation because resources available during typical conditions would fall 200 MW short of extreme load conditions, *absent operational mitigation*. The Northeast Power Coordinating Council (NPCC) notes that New England has between 1,145 and 4,020 MW of operational mitigation available for use this summer (NPCC, 2026). NERC only included the lower end of this range in its analysis, so even more capacity is likely to be available if needed. Operational mitigation techniques are an important tool for operators to overcome high impact and low frequency grid stress events, such as the once-in-a-decade extreme load conditions modeled here.

When operational mitigation practices are included—as they should be, especially in extreme conditions—New England has sufficient resources to meet both peak and extreme load. All available resources exceed extreme weather-driven load by nearly 900 MW.



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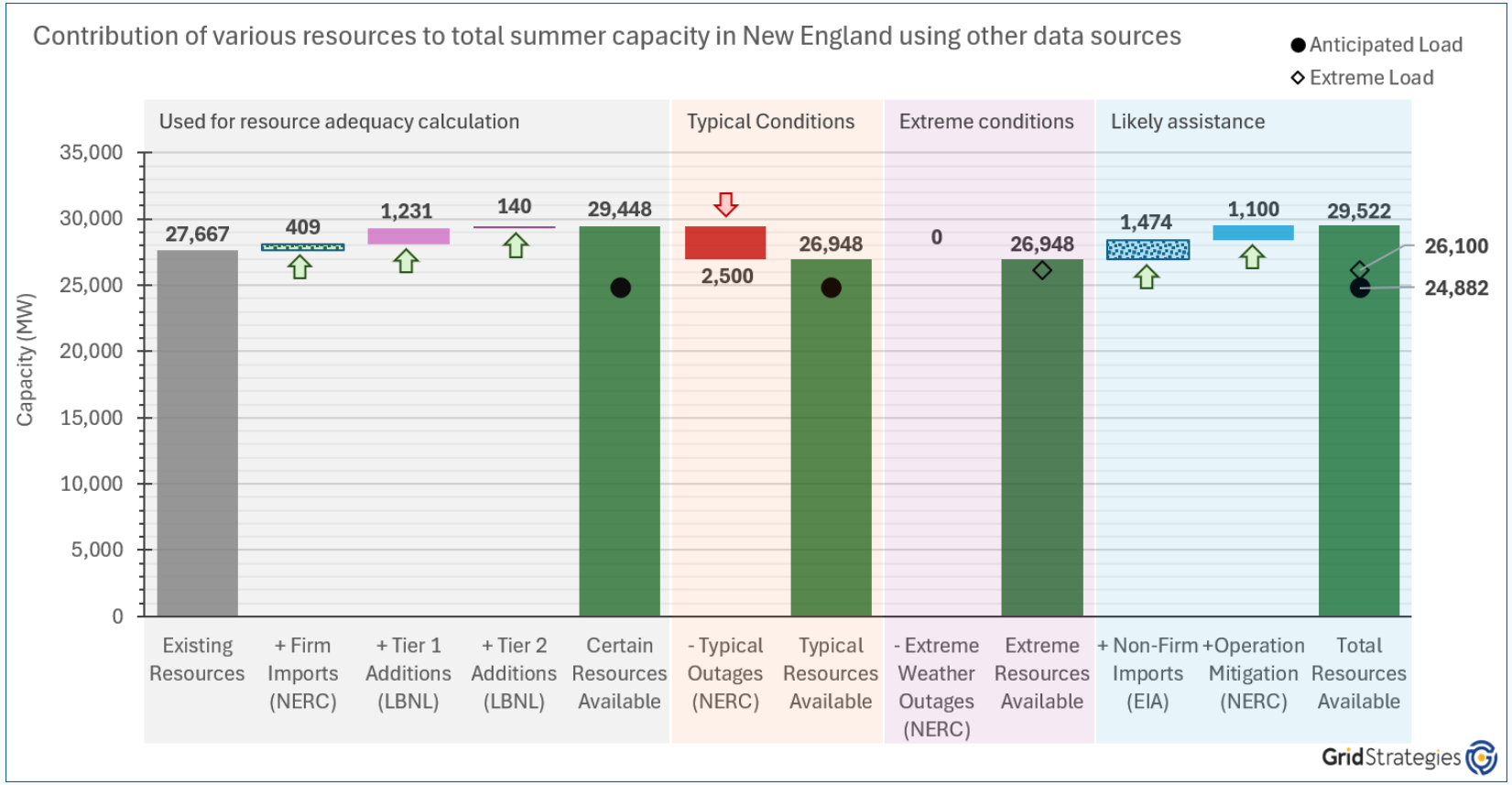
DATA SOURCE | NERC " SRA" (2026); Northwest Power Coordinating Council (NPCC) "Reliability Assessment for Summer 2026" (2026)

System adequacy analysis using other data sources show enough resource capacity to cover both load conditions in New England, even if operational mitigation is omitted.

When NERC data is combined with likely-to-connect **Tier 1** and **Tier 2** resources from the LBNL interconnection queue data and historic **non-firm imports** from the U.S. Energy Information Administration (EIA),* the headroom available to serve New England load increases further.

This analysis shows that New England has nearly 2,100 MW of resource headroom under typical conditions and 900 MW under extreme conditions, even without additional assistance. This headroom increases to 4,600 MW and 3,400 MW, respectively, once likely assistance is included.

New England has sufficient resources to serve its load even if operational mitigation procedures and additional non-firm imports were unavailable.



*We derate LBNL's interconnection queue data using historic regional- and queue phase-specific withdrawal rates. Tier 2 additions are further reduced by half. Non-firm imports reflect the maximum coincident import into New England summer months between 2022 and 2025, less NERC reported firm imports.

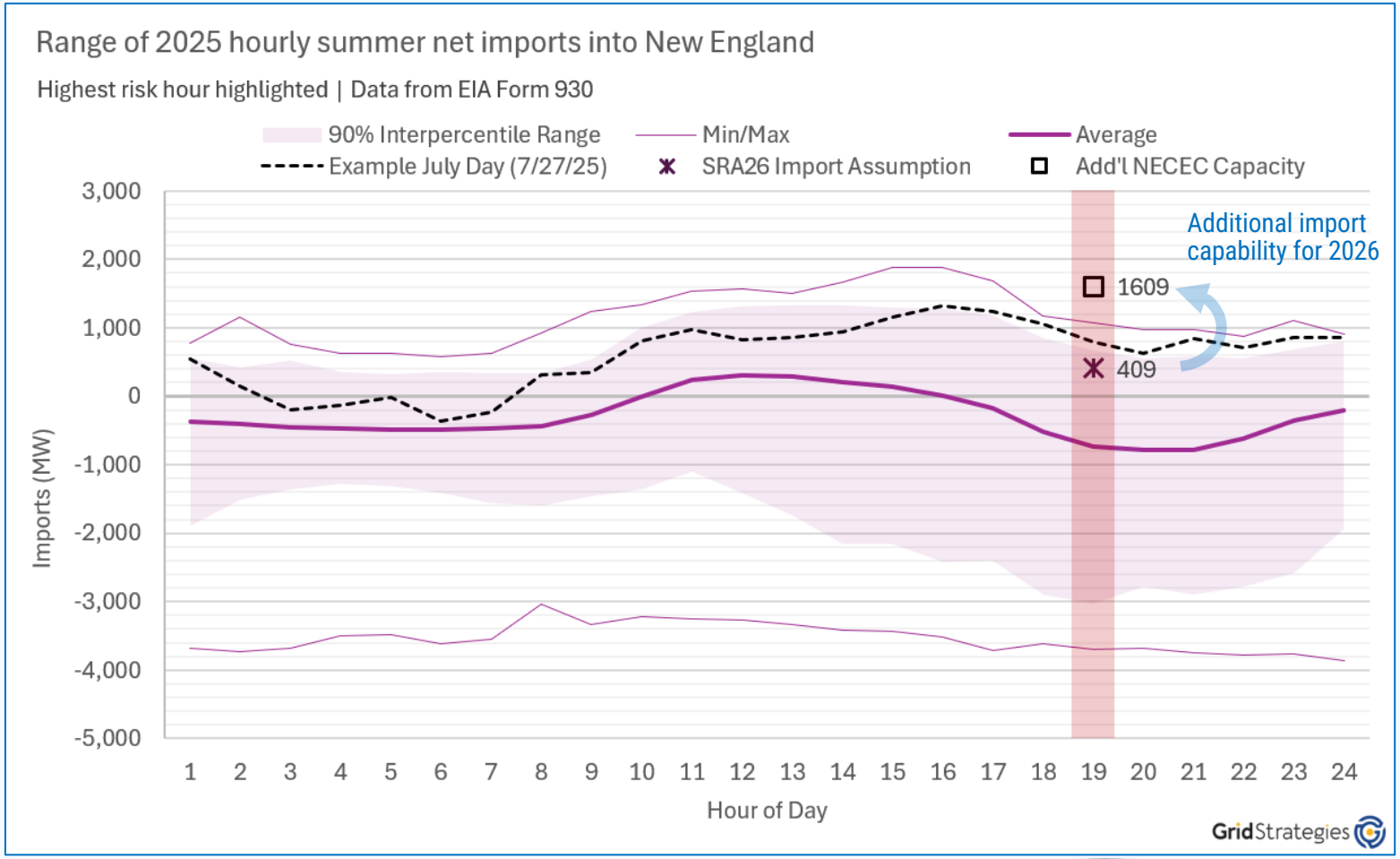
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DATA SOURCE | NERC "SRA" (2026); Rand, J. et al. "Interconnection Queue Dataset & Summarized Data Files, through 2024" (2025); EIA "Form 930 Interchange Data" (2022)–(2026)

New England import assumptions used in the 2026 Summer Reliability Assessment are lower than what is likely available from neighboring regions given the recent addition of new transfer capability.

To better understand 2026 import capabilities, it is instructive to consider hourly net imports into New England during the summer months in 2025. The dotted black line show hourly imports on an example July day. If hourly imports of every day in June – September 2025 were plotted, those values would all fall between the thin purple minimum and maximum lines, and the middle 90% of all values would fall within the purple envelope (90% interpercentile range, IPR). The average of all daily imports is shown as the thick line. The shaded red bar highlights peak summer demand hour.

NERC identified 409 MW of firm imports that would be available during highest risk hour in 2026. This value well aligns with what could have been expected in 2025 on a high import day (towards the upper end of the 90% IPR). As NERC highlights, however, this value does not include the 1,200 MW of new import capability added with the completion of the New England Clean Energy Connect (NECEC) line to Hydro-Québec (HQ). **This additional non-firm import capability further increases the headroom available to New England, by as much as the operational mitigation techniques.**



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DATA SOURCE | EIA "Form 930 Interchange Data" (2022)–(2026)

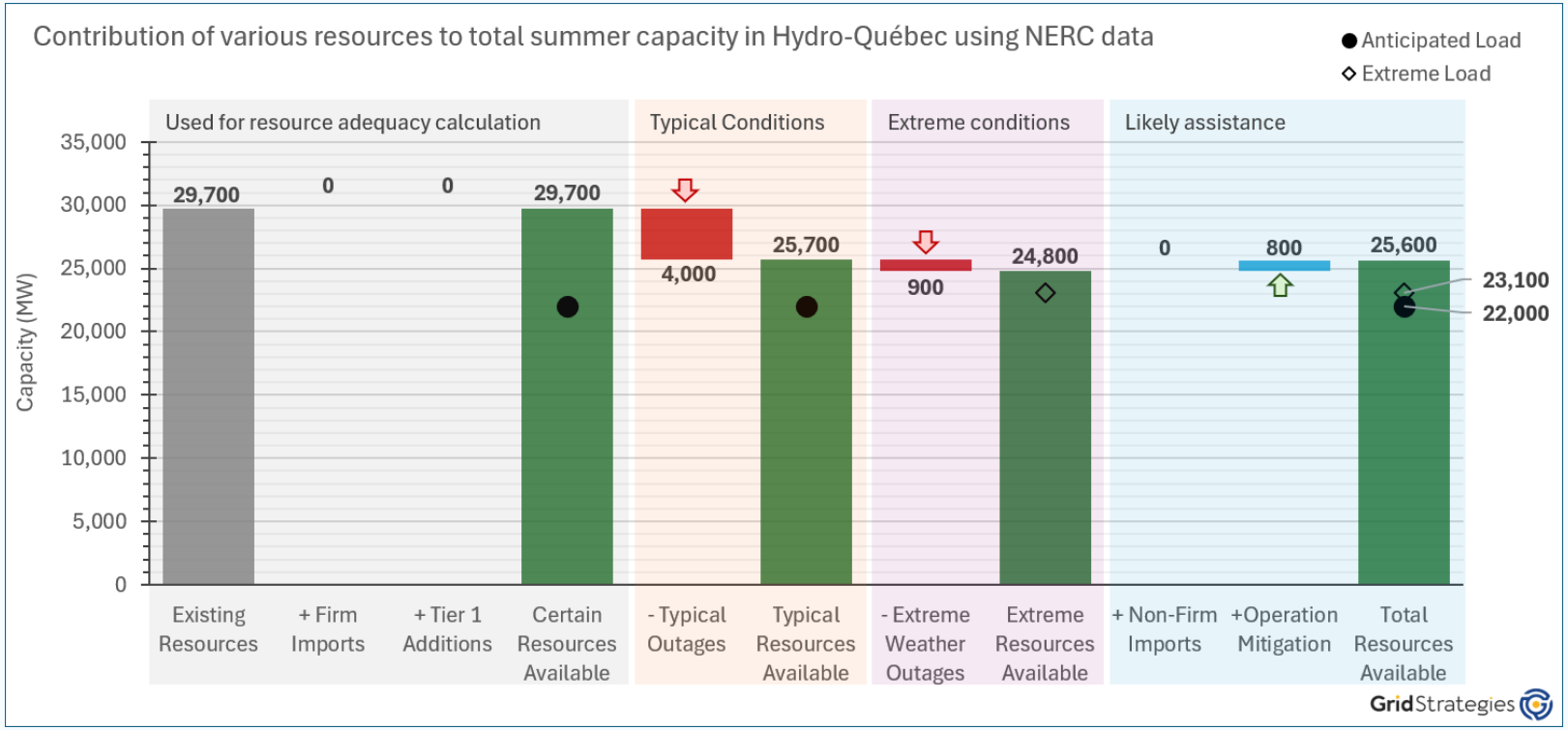
New England import assumptions used in the 2026 Summer Reliability Assessment are lower than what is likely available from neighboring regions given the recent addition of new transfer capability.

The additional 1,200 MW of import capability into New England supplied by NECEC will be useful so long as there is available generation on the other side of the facility to import.

Resource availability in Hydro-Québec was also analyzed in the 2026 Summer Assessment. NERC data shows that HQ will have 3,700 MW of excess availability under typical conditions and 1,700 MW under extreme conditions, absent operational mitigation. The NPCC identifies HQ's export capability as a key contributor to wide-area 2026 summer reliability, including in New England (NPCC, 2026).

Even under the worst case that HQ experiences extreme conditions when New England desires additional imports, NERC data shows that HQ will have enough resources to meet its own needs and export excess power to the U.S.

Notably, HQ exports power to both New York and New England. NERC found that New York has normal risk this summer, without additional non-firm import assistance. This should ease any need for HQ to export excess power to both U.S. regions in the event of coincident extreme events, prioritizing more assistance for New England.



Region	2024 Import Capability from HQ (NERC, 2024)	Additional 2026 Import Capability from HQ (NERC, 2026)	Combined Import Capability from HQ
ISO-NE	1000	1200	2200

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SOURCE | NERC " SRA" (2026); NERC "Interregional Transfer Capability Study - Part 1 Results" (2024); NPCC "Reliability Assessment for Summer 2026" (2026)

Main Takeaway

NERC data shows that New England has enough resource capability to serve its load under both typical and extreme conditions, so long as operational mitigation strategies are employed as designed. This headroom to serve load increases when considering likely-to-connect resources from the interconnection queues, even without operational mitigation. Finally, additional imports from Canada will be available to serve load this summer.

Taken together, these resources provide New England with a comfortable reserve margin above its target to serve load this summer.

Summer 2026 System Adequacy in the Northwest

Capacity adequacy analysis using industry-reported data shows the Northwest has sufficient resources to meet load under both typical and extreme weather conditions.

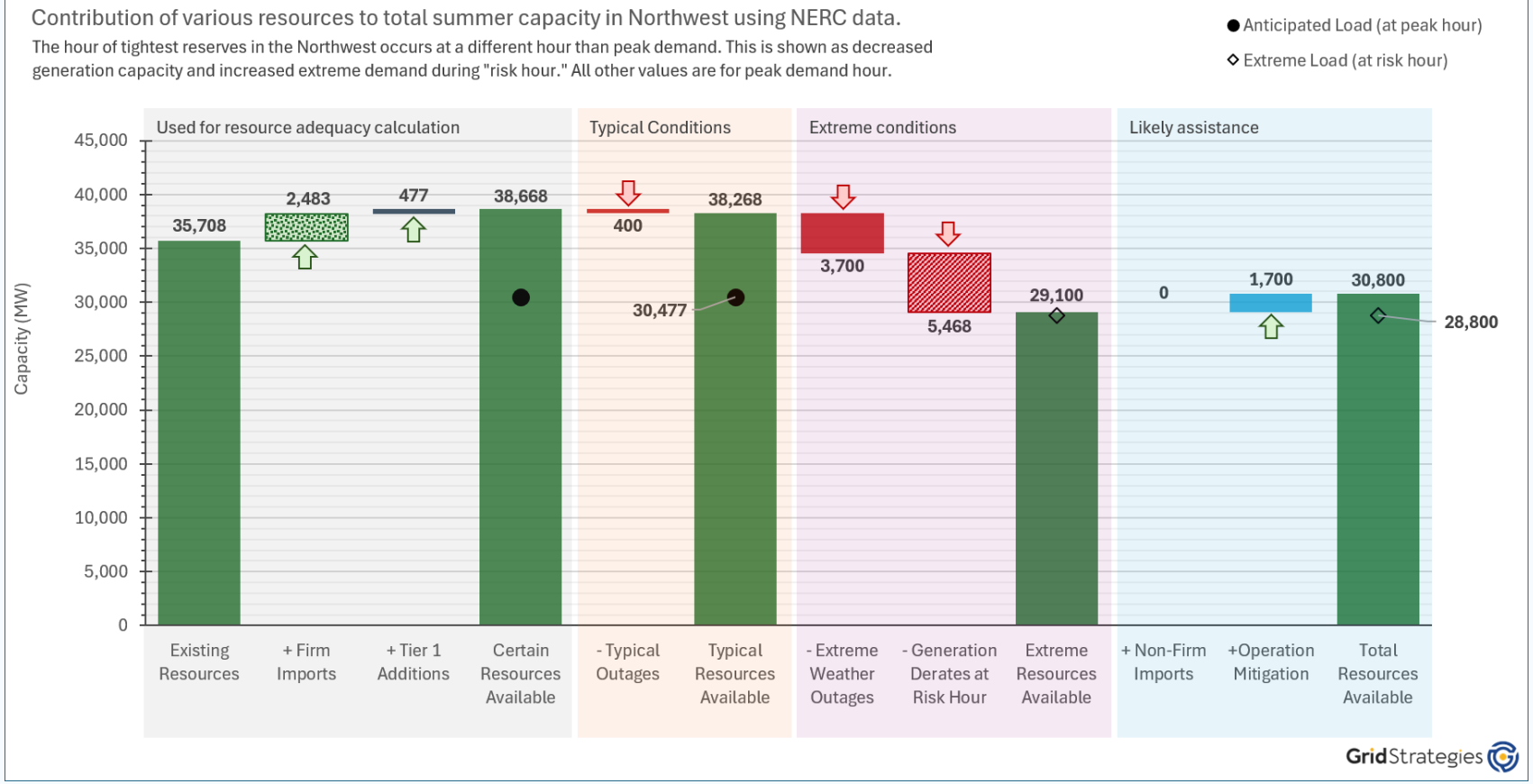
Resource projections reported to NERC show the Northwest has ample resources—over 8,000 MW—to serve peak load. Under extreme load conditions, reported data shows this headroom reduces to 300 MW, absent usage of other available tools not already included in that calculation. Given this low headroom during extreme conditions at risk hours,* NERC identified that a small amount of unserved energy is possible and designated the region as elevated risk for summer 2026.

Like in New England, the low headroom during extreme, once-in-a-decade load conditions is only present absent operational mitigation. Industry-reported data indicates the addition of operational mitigation increases this headroom to 2,000 MW.

Even at highest risk hour, industry-reported data shows that the Northwest has sufficient resources to meet load under both typical and extreme conditions, especially given operational mitigation.

Contribution of various resources to total summer capacity in Northwest using NERC data.

The hour of tightest reserves in the Northwest occurs at a different hour than peak demand. This is shown as decreased generation capacity and increased extreme demand during "risk hour." All other values are for peak demand hour.



*Unlike other regions, high risk hours in the Northwest occur at times other than peak demand. Expected load at risk hour under typical conditions was not reported by NERC, so we can only assess typical conditions at peak load hour and extreme conditions at risk hour.

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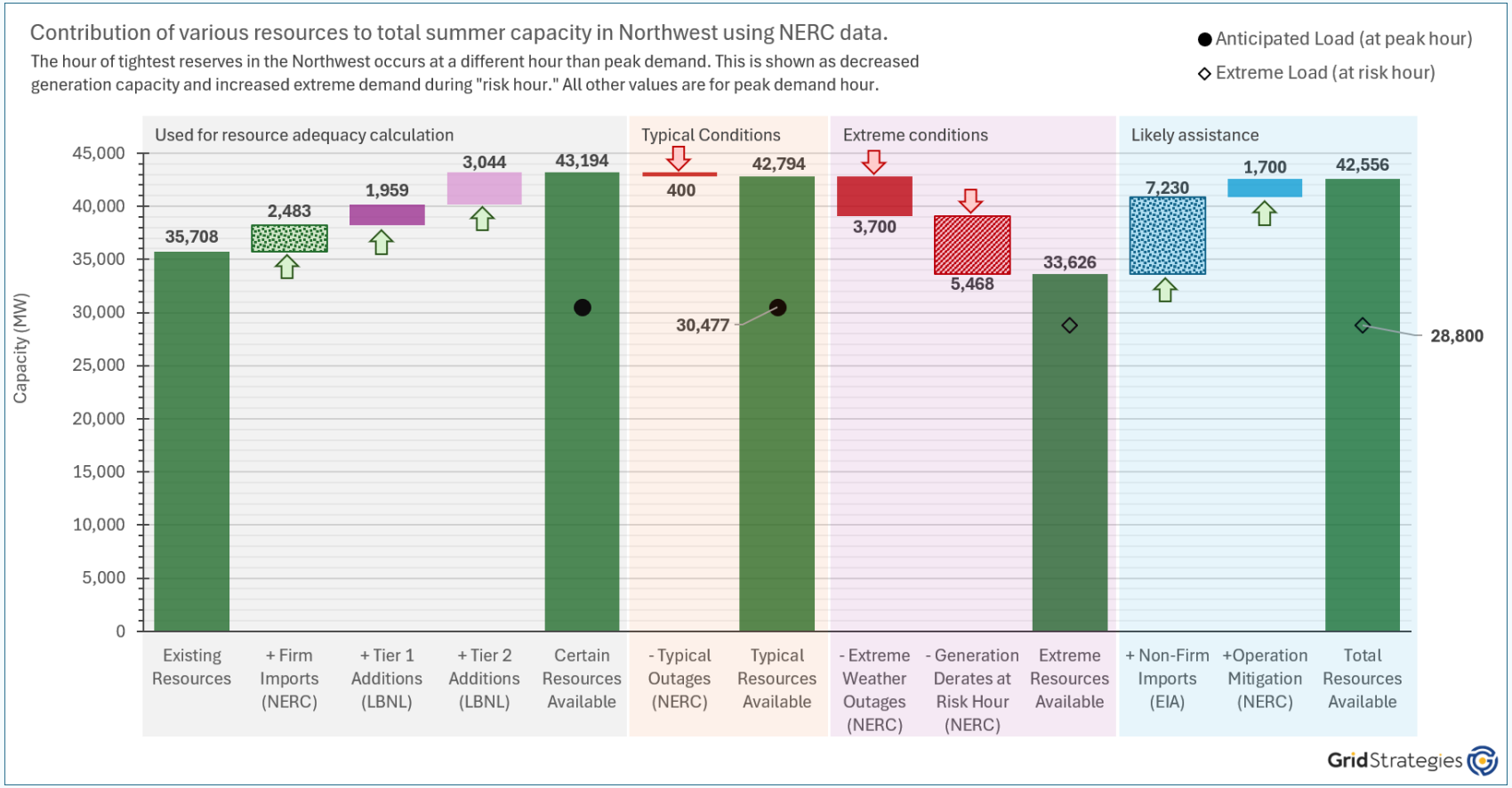
DATA SOURCE | NERC " SRA" (2026)

System adequacy analysis using other data sources shows enough resource capacity to cover both load conditions in the Northwest, even if operational mitigation is omitted.

When NERC data is combined with likely-to-connect **Tier 1** and **Tier 2** resources from the LBNL interconnection queue data and historic **non-firm imports** from EIA,* the headroom available to serve the Northwest load increases further.

This analysis shows that the Northwest has over 12,300 MW of resource headroom to serve peak load under typical conditions and over 4,800 MW under extreme conditions at highest risk hour, even without additional assistance. This headroom under extreme conditions at peak hour increases to over 13,700 MW once likely assistance from non-firm imports and operation mitigation is included.

When NERC assumptions are combined with likely-to-connect resources from the LBNL interconnection queue database and historic imports from EIA, the Northwest is shown to have ample resource capability to meet all load conditions.



*We derate LBNL's interconnection queue data using historic regional- and queue phase-specific withdrawal rates. Tier 2 additions are further reduced by half. Non-firm imports reflect the maximum coincident import into the Northwest during summer months between 2022 and 2025, less NERC reported firm imports.

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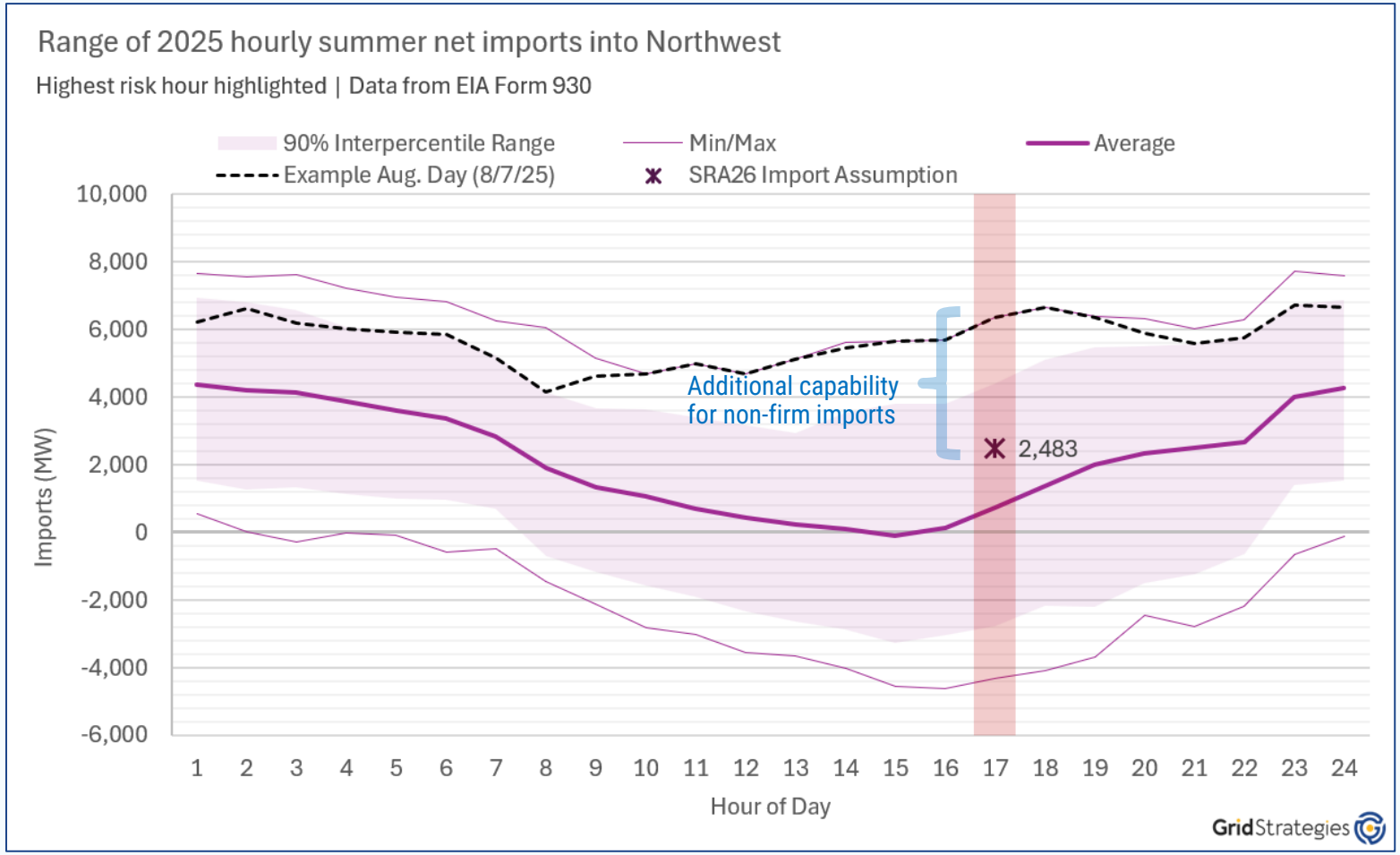
DATA SOURCE | NERC "SRA" (2026); Rand, J. et al. "Interconnection Queue Dataset & Summarized Data Files, through 2024" (2025); EIA "Form 930 Interchange Data" (2022)–(2026)

Northwestern import assumptions used in the 2026 Summer Reliability Assessment is lower than what may be available from neighboring regions.

The figure to the right describes the full range, 90% interpercentile range, and average net hourly imports into the Northwest for every summer day (June – September) in 2025. The daily hourly imports for the August 2025 day with highest afternoon imports is also shown as an example. This captures both firm and non-firm imports. High risk hour (17:00) is highlighted.

NERC assumes just shy of 2,500 MW of firm imports will be available to the Northwest this summer. This is significantly lower than the 6,350 MW of resources imported by the Northwest at risk hour in August 2025. This suggests that a significant amount of non-firm imports are likely to be available to the Northwest, depending on the conditions in neighboring regions.

As previously shown, NERC's assessment of neighboring Western regions all show ample resource capability this summer, with reserve margins between 28% and 54% under typical conditions, well above target margins. Import assistance from these regions should be available up to the historic import limit. The addition of large quantities of solar and batteries in California should also increase its ability to export to the Northwest during the highest risk hour.



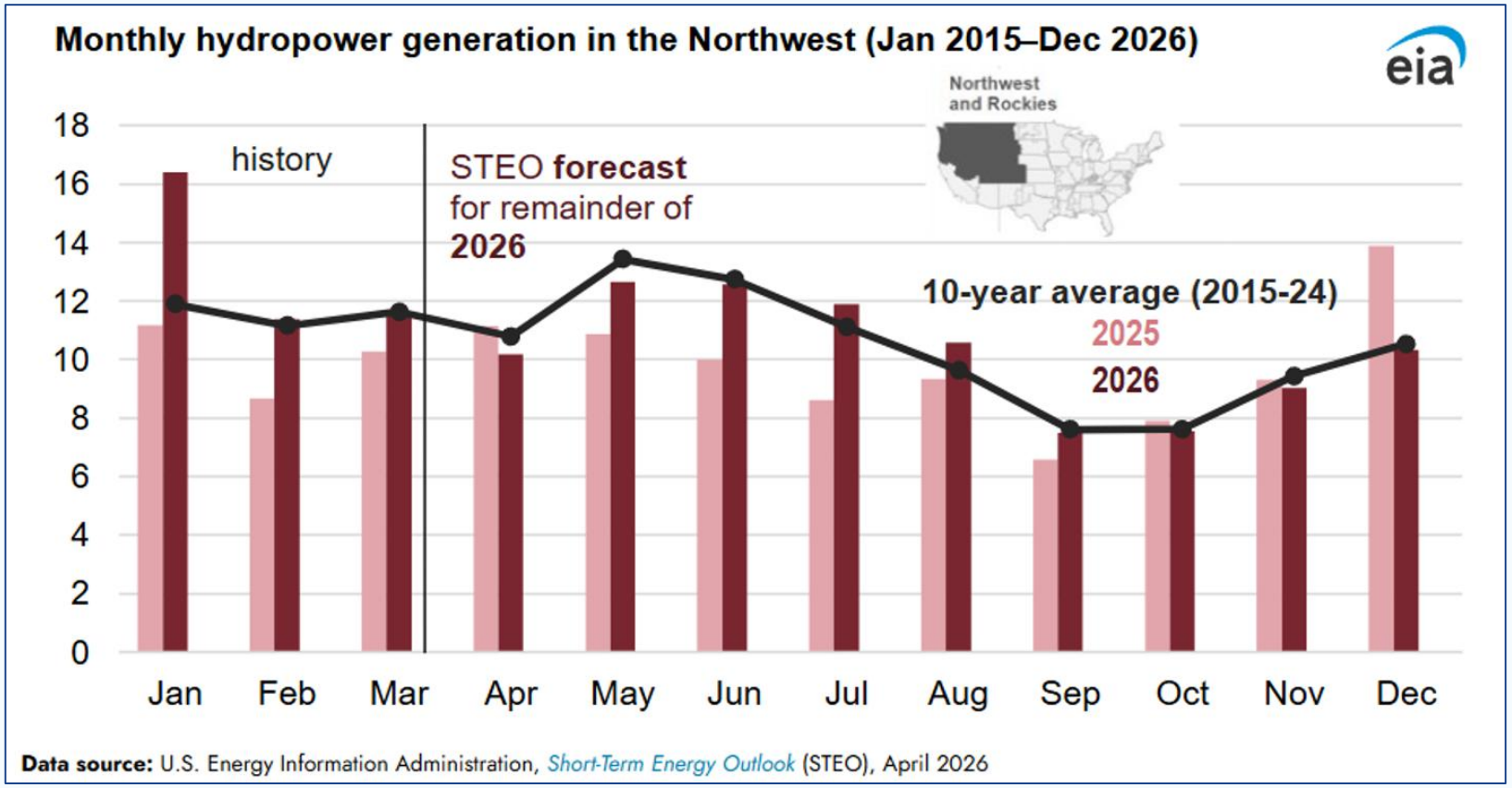
DATA SOURCE | EIA "Form 930 Interchange Data" (2022)–(2026)

Hydroelectric resource availability may not be as bad this year as forecasted in the 2026 Summer Reliability Assessment.

As NERC notes, the combination of historic drought and increased ambient temperatures resulted in little snowpack during the 2025/2026 winter, which typically recharges hydroelectric reserves in the spring and summer as it melts. This led NERC to forecast low hydroelectric activity for the Northwest in the 2026 SRA.

An El Niño weather event was predicted but not yet certain when the 2026 SRA was released. Since then, the National Oceanic and Atmospheric Administration (NOAA) has confirmed that we are experiencing an El Niño (NOAA, 2026a). In the near-term, NOAA and EIA anticipate the El Niño will bring near average precipitation through summer and fall, partially restoring reserves for at least the upcoming season (NOAA, 2026b)(EIA, 2026).

The EIA expects the combination of high 2025/2026 winter rainfall and forecasted high summer 2025 rainfall (see chart to right) to restore hydroelectric reserves in northwestern dams to their 30-year averages, including in August and September, the months identified by NERC as highest concern (EIA, 2026).



SOURCE | NOAA (2026) www.weather.gov/twc/enso; EIA (2026) www.eia.gov/todayinenergy/detail.php?id=67444; NOAA (2026) www.nwrfc.noaa.gov/water_supply/ws_forecasts.php?id=TDAO3&datepick=05/29/2026

Main Takeaway

Industry-reported data shows that the Northwest has sufficient resource capability to serve its load under both typical and extreme conditions, especially when operation mitigation procedures are included. This headroom increases when considering likely-to-connect resources from the interconnection queues. In the event of extreme events that stress the grid, significant additional non-firm imports from neighboring regions should be available to serve load. Finally, El Niño conditions this summer are likely to restore historically low hydroelectric reserves to 30-year averages.

Taken together, these resources provide the Northwest with a comfortable reserve margin above target capacity to serve load this summer.

Conclusions and Solutions

All regions have sufficient resources to meet 2026 summer load, including the two regions NERC identified as at elevated risk. The combination of regional resources, imports, and operational mitigation enables sufficient capacity across the board.



- NERC data shows that all regions have sufficient capacity—regional generation, imports, and operational mitigation procedures—to meet load under both typical and extreme conditions.
- Resource capacity forecasts compiled by NERC persistently underestimated the rate of new generation additions, especially for renewable energy resources.
- When NERC's forecasts of new capacity additions are replaced with historically-informed data from the interconnection queues, the headroom of available capacity increases to well above target reserve margins in all regions.
- While hydropower availability under historic drought conditions should not be ignored in the long-term, hydroelectric conditions in the Western U.S. are likely to return to 30-year averages this summer.



- Implementing operational mitigation procedures during grid stress conditions is standard practice and should not be overlooked when assessing system adequacy.
- As NERC highlights in the 2026 SRA, calling on large loads to reduce their demand is another important tool to overcoming grid stress conditions. Grid operators can look for opportunities to increase the number of large load customers contracted to provide this service.



- NERC capacity assessments do not include non-firm imports from neighbors that regularly occur during both typical and grid stress conditions. A look at historic imports from neighboring regions with excess generation capacity suggests that plenty of non-firm assistance will be available to the regions with tighter reserve margins.