

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-21
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit S: Department, Order No. 202-25-12 (Dec. 23, 2025)



Department of Energy
Washington, DC 20585

Order No. 202-25-12

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The R.M. Schahfer Generating Station (Schahfer) is an electric generating facility in Wheatfield, Indiana. Schahfer is owned and operated by Northern Indiana Public Service Company (NIPSCO), a division of NiSource Inc. Schahfer consists of two 129 MW natural-gas fired units and two coal-fired units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW).³ Unit 17 and Unit 18 began operations in 1983 and 1986 respectively. Unit 17 and Unit 18 are both slated to cease operations in December 2025.⁴

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.⁵ MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."⁶ MISO noted that over 60% of all

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024), <https://www.eia.gov/electricity/data/eia860/>.

⁴ As coal-fired facilities, it would be difficult for the Schahfer Units 17 and 18 to resume operations once they have been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Schahfer were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

⁵ *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. See *Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

⁶ MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

“MaxGen” events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.⁷

In December of 2023, MISO released an “Attributes Roadmap,” in which it presented “an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape.”⁸ Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.⁹

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, “*MISO’s Response to the Reliability Imperative*.”¹⁰ In a section of that report entitled “Risks in Non-Summer Seasons,” MISO again stressed that it has resource reliability concerns outside of the summer season:

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region’s historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.¹¹

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk “because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years.”¹²

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Indiana.¹³

⁷ *Id.* at 3-4.

⁸ MISO, *Attributes Roadmap*, at 3 (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>.

⁹ *Id.* at 11.

¹⁰ MISO, *MISO’s Response to the Reliability Imperative* (Updated February 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>.

¹¹ *Id.* at 12.

¹² NERC 2024 Long-Term Reliability Assessment, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

¹³ MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.¹⁴ The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.¹⁵ The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.¹⁶ Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.¹⁷

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.¹⁸ Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.¹⁹

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.²⁰ The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.²¹ In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.²² Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing

¹⁴ OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

¹⁵ *Id.* at 2.

¹⁶ *Id.* at 7.

¹⁷ *Id.* at 9.

¹⁸ *Id.* at 7, 9.

¹⁹ *Id.*

²⁰ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

²¹ *Id.* P 84.

²² See generally, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), <https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply>.

resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, “Declaring a National Energy Emergency,” in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”²³ The Executive Order adds: “Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”²⁴ In a subsequent Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid,” President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”²⁵

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”²⁶

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”²⁷ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to

²³ Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency>.

²⁴ *Id.*

²⁵ Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.

²⁶ U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025_07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

²⁷ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. See 42 U.S.C. § 7151(b).

identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Schahfer Units 17 and 18 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

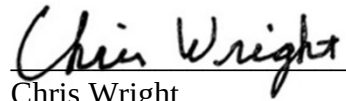
To ensure Schahfer Units 17 and 18 will be available if needed to address emergency conditions, Schahfer Units 17 and 18 shall remain in operation until March 23, 2026.

Based on my determination of an emergency set forth above, I hereby order:

- A. From December 23, 2025, MISO and NIPSCO, shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of the Schahfer Units 17 and 18.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Schahfer Units 17 and 18 has operated in compliance with the allowances contained in this Order.
- C. All operation of Schahfer Units 17 and 18 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO and NIPSCO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. NIPSCO is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for Schahfer Units 17 and 18 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Schahfer Units 17 and 18 shall not be considered capacity resources.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

A handwritten signature in black ink that reads "Chris Wright". The signature is written in a cursive style and is positioned above the printed name and title.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commission

Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

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Exhibit SS: Behr, P., *PJM to ratchet down projected AI power demand for eastern US*
(Jan. 6, 2026)

PJM to ratchet down projected AI power demand for eastern US

An updated analysis from the regional grid operator is expected to provide a reality check on data center growth.



BY: **PETER BEHR** | 01/06/2026 06:53 AM EST



A data center is seen under construction last year near the Susquehanna nuclear power plant in Pennsylvania. | Ted Shaffrey/AP

ENERGYWIRE | Across the U.S., energy policymakers and power grid operators have three broad goals at the top of their 2026 priority lists: enable AI dominance. Secure electricity supply. Keep power prices from spiraling.

But hitting those targets is challenged by a simple question that remains hard to answer: What's real and what's hype when it comes to data center demand for electricity?

Advertisement



The dilemma is front and center at PJM Interconnection, the nation's largest regional power grid, serving 67 million people in 13 states from the Atlantic coast to Chicago. Later this month, PJM plans to release an updated estimate of future electricity demand from large users. The report is expected to provide a serious reality check to the projections that developers and utilities make about future data center growth.

PJM Chief Operating Officer Stu Bresler said last month that PJM's overall power demand forecast for the year beginning in mid-2027 will be "appreciably lower" than current projections. PJM wants more evidence on how fast and how large new data centers can actually be built with shortages of chips, electronics and specialized construction teams.

Overestimating AI data center growth threatens to burden consumers with billions of dollars in excessive investments. Underestimating it increases risks of power shortages and blackouts while also undercutting [current U.S. leadership](#) as a developer of AI technology.

"At a time when utilities forecast hundreds or thousands of megawatts of growth, improving forecasts by even a few percentage points in the right direction — up or down — can impact billions of dollars in investments and customer bills," said David Rosner, a member of the Federal Energy Regulatory Commission, last year.

"Put simply, we cannot efficiently plan the electric generation and transmission needed to serve new customers if we don't forecast how much energy they will need as accurately as possible," Rosner said.

The most detailed [analysis](#) of future U.S. data center demand, issued a year ago by the Department of Energy's Lawrence Berkeley National Laboratory, could not get close to a precise prediction. Instead, it estimated the amount of the U.S. electricity output consumed by data centers in 2028 could range anywhere from 6.7 percent to 12 percent.

"We're all going around trying to solve a problem that we haven't even defined yet," said Caitlin Marquis, managing director of Advanced Energy United, a coalition of clean technology developers and energy users. "It's definitely worthwhile making sure that we know what we're planning for, because the costs of getting that wrong are significant either way."

But a clearer picture may be clouded by [consumer resistance](#) that puts some data center projects in doubt, and a fight in Washington over the power of the states to regulate AI.

President Donald Trump's executive order in October declares global AI "dominance" to be a national security imperative and seeks to impose White House control over state AI policymaking.

Governors from both political parties who head AI-leading states oppose Trump's moves. But governors have also been among the biggest AI cheerleaders because of the investment and tax dollars and jobs data centers deliver.

Acting on a directive from the Department of Energy, FERC is trying to [forge new rules](#) for assessing data center growth, with an uncertain timetable. PJM is a test case in the debate because of its concentration of existing data centers, the largest in the world by industry estimates.

Forecasts that 'defy logic'

PJM's long-term forecast projected an unprecedented surge in peak power use by data centers, factories and cryptominers that would require adding 32,000 megawatts of new generation, batteries, and demand response between 2024 and 2030. Of this, PJM expected 30,000 MW to come from data centers.

PJM's total generating capacity increased by only about 2,000 MW, or 1 percent, in the past year.

PJM's demand forecasts have been amped up by tech companies plowing billions of dollars into the AI race, joined by investor-backed speculators seeking to secure marketable sites for new centers, according to participants in PJM's review.

The prospect of skyrocketing electricity demand is already showing up on utility bills, according to PJM's independent market monitor, Joseph Bowring of Monitoring

Analytics. PJM charges ratepayers for incentive payments to generators to keep plants operating in future years, and those payments have escalated in the past two years because of expected data center construction.

Kent Chandler, a senior fellow at the R Street Institute and a former Kentucky utility regulator, said some PJM officials have acknowledged privately to him that the forecasts coming from utilities “sort of defy logic.”

“There just aren’t enough transformers and conductors and towers and engineers to accommodate the load growth that some of these utilities are proposing,” Chandler said.

That’s true not just within PJM, he said, but across the country.

Potential roadblocks to data center projects are detailed in a new analysis by ICF International. The consulting firm's software mapping program identifies potential data center sites based on key factors like the availability of grid power, favorable zoning and fiber-optic networks. The list of prime data center project locations is shrinking rapidly in Northern Virginia and many other areas, the ICF analysis shows.

“The challenge is knowing which data center is real versus a phantom project,” said Himali Parmar, ICF vice president for energy markets.

Developers are making multiple applications for the same project because it’s relatively cheap to do so, she said. Their applications are shielded by confidentiality agreements that developers demand and utilities accept rather than get in arguments with a potentially huge customer.

“Am I looking at 40 gigawatts of new load requests, or is it 70, or is it 80? That’s a challenge with this lack of transparency,” she said. “PJM does not know what’s coming its way.”

“Utilities have an inherent financial bias to overstate demand” in their forecasts, Chandler said. Strong demand forecasts can move utilities’ stock prices higher and result in increased investment in grid infrastructure that boosts financial returns, grid experts explain.

PJM officials “don't feel comfortable with what utilities are putting in,” Chandler said. “They don't necessarily have the information or expertise [to contradict the utility forecasts]. That’s something they're figuring out now,” Chandler added.

An advance clue to the revisions PJM is preparing may be data from the preliminary report on load growth PJM published last year — the report that will be updated this month.

It showed some utilities in PJM making significantly different assumptions about the reality of utilities' data center power demand.

An example is the contrast in load growth forecasts from Allentown, Pennsylvania-based PPL Corp., and Dominion Energy Inc., the Richmond, Virginia, power company. Dominion serves “data center alley” in Northern Virginia, the largest cluster of the facilities anywhere. Northeast Pennsylvania, PPL's territory, is seeing a rush of AI data center development proposals.

PJM published two forecasts. One was a “capacity” figure based on developers' unverified requests for transmission capacity within PJM to manage the load growth the developers are projecting. The second forecast was the utilities' own estimate of actual load growth.

PPL capacity forecast shows demand soaring more than 3,000 percent to 13,412 MW, in 2029. PPL's own demand estimate indicates that PPL expects about 80 percent of that new data center construction to be completed by 2029.

Dominion, on the other hand, which has the most experience within PJM by far with its track record of data center construction, said that only about 30 percent of the developers' power requests will actually materialize in 2029.

An analysis by ClearView Energy Partners said PJM is very likely to require better forecasting by utilities of data center demand. Its analysts noted that PJM board chair David Mills has suggested PJM could require state officials to review utilities' power demand forecasts and may call for scrutiny of forecasts by outside analysts looking at crucial supply-chain issues that could slow new data center construction.

“We would be better off if operators like PJM got the information directly from the customer and could have a back-and-forth with them to fully understand what they're doing,” Chandler said.

UP NEXT IN **THIS EDITION OF ENERGYWIRE**

Congress would boost oil and gas spending in fiscal 2026 package

BY IAN M. STEVENSON



UNITED STATES OF AMERICA
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Federal Power Act Section 202(c)	)	Order No. 202-26-21
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Exhibit T: Congressional Research Service, *Federal Power Act: The Department of
Energy's Emergency Authority* (June 12, 2025)

Federal Power Act: The Department of Energy's Emergency Authority

June 12, 2025

Congressional Research Service

<https://crsreports.congress.gov>

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Section 202(c) of the Federal Power Act (16 U.S.C. §824a(c)) grants the Secretary of Energy certain authorities over the temporary operation of the electricity system during emergencies. Actions by the Trump Administration have highlighted this authority and raised questions about its future implementation. This report provides a brief history of the emergency authorities and discusses current issues.

History of Section 202(c)

The Federal Power Act was enacted in 1935 and included emergency authority language. At the time, federal oversight of the electricity system was conducted by the Federal Power Commission (FPC). Now, the Federal Energy Regulatory Commission (FERC) has most responsibilities for electricity system oversight—but not for emergencies. The emergency authority was transferred to the Secretary of Energy when the Department of Energy (DOE) was established by the Department of Energy Organization Act (P.L. 95-91) in 1977. Hereinafter, the emergency authority is described as residing with DOE.

Section 202(c) provides DOE broad discretion to require almost any change to the operation of the U.S. electricity system on a temporary basis. Specifically, DOE may “require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”

DOE may execute this authority during war or at any other time it “determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes.” This report focuses on the authority as used during emergencies, not war, and it focuses on DOE’s authority—it does not discuss other energy emergency authorities.¹

In 2015, Congress amended Section 202(c) to specify how the emergency authority should interact with environmental requirements for power plants. In practice, the amendments prioritize electric reliability over environmental outcomes, essentially by providing a waiver of federal, state, or local environmental laws and regulations during times of emergencies.

This waiver has limitations. First, DOE emergency orders that may result in conflicts with environmental requirements may be issued only for 90-day periods. They may be renewed for additional 90-day periods as long as DOE deems these renewals necessary to meet the emergency.

Second, if an emergency order would result in a violation of a federal, state, or local environmental law or regulation, DOE must ensure the order is in effect “only during hours necessary to meet the emergency and serve the public interest.” Lastly, DOE must “to the maximum extent practicable” ensure the order is consistent with environmental laws or regulations and “minimizes any adverse environmental impacts.”

DOE Implementation

DOE’s regulations for implementing its emergency authority were finalized in 1981.² The regulations define terms, including “emergency,” and specify requirements for requesting an emergency order.

¹ For example, in the 1970s, Congress passed several laws granting the President certain authorities to respond to energy shortages at the time. A discussion of those laws is beyond the scope of this report.

² 10 C.F.R. §§205.370-205.379.

The Section 202(c) emergency authority is focused primarily on short-term situations—though, as shown below, DOE has exercised this authority in situations of varying duration. DOE's regulations emphasize the short-term nature of “emergencies” in this context. In the 1981 rulemaking, DOE explained,

The DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the ‘Definition of Emergency’ to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.³

DOE and FPC have used the emergency authority several dozen times since 1935 in response to different kinds of emergencies.

DOE's website contains information on use of the emergency authority from 2000.⁴ From 2000 through May 2025, DOE used its emergency authority in response to 19 events. Eleven events were weather-related and included hurricanes, heat waves, and winter storms. Some events prompted multiple emergency orders, either because more than one utility experienced emergency conditions (e.g., Winter Storm Elliot in 2022) or because the initial emergency order was extended (e.g., the California energy crisis of 2000-2001).

Details on the use of the Section 202(c) emergency authority prior to 2000 are not available in a single DOE repository; they are therefore more difficult to comprehensively compile. According to one compilation, the emergency authority was used 29 times prior to 2000; 22 of these occasions were in association with World War II.⁵

The duration of emergency orders under Section 202(c) has varied; some have lasted just a few hours, while others have been extended to cover events lasting more than a year. Among the orders listed on DOE's website, the shortest order CRS identified occurred in response to a heat wave in Texas in September 2023. DOE granted an emergency order in this case for four hours on each of two days to respond to the highest levels of expected electricity demand.⁶ The order allowed one coal-fired unit and 16 natural gas-fired units to operate in violation of limits on sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and wastewater during those hours, if required to maintain reliability.

In the longest event CRS identified, DOE granted multiple renewals to a request to allow two coal-fired units in Virginia to continue operating, as needed for reliability, in violation of mercury emissions limitations while a transmission facility was constructed. Emergency orders in response to that event were in effect from June 16, 2017, to March 8, 2019.⁷

³ Department of Energy (DOE), Economic Regulatory Administration, “Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power” (final rule), 46 *Federal Register* 39985, August 6, 1981, https://archives.federalregister.gov/issue_slice/1981/8/6/39984-39991.pdf#page=2.

⁴ See DOE, “DOE's Use of Federal Power Act Emergency Authority,” <https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority>; and DOE, “DOE's Use of Federal Power Act Emergency Authority – Archived,” <https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority-archived>.

⁵ Benjamin Rolsma, “The New Reliability Override,” *Connecticut Law Review*, vol. 57, no. 3 (May 2025).

⁶ Additional information is available at DOE, “Federal Power Act Section 202(c): ERCOT September 2023,” <https://www.energy.gov/ceser/federal-power-act-section-202c-ercot-september-2023>.

⁷ Additional information is available at DOE, “Federal Power Act Section 202(c) – PJM Interconnection & Dominion Energy Virginia, 2017,” June 19, 2017, <https://www.energy.gov/oe/articles/federal-power-act-section-202c-pjm-interconnection-dominion-energy-virginia-2017>.

Trump Administration Actions

On April 8, 2025, President Trump issued Executive Order (E.O.) 14262, “Strengthening the Reliability and Security of the United States Electric Grid.”⁸ E.O. 14262 directs DOE to “streamline, systemize, and expedite” its processes for issuing emergency orders when “the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure.” A blackout is an example of a temporary interruption of electricity supply.

The E.O. additionally directs DOE to develop a protocol to identify generation resources that are critical to system reliability. The protocol must “include all mechanisms available under applicable law, including Section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained.” Further, the protocol must prevent, “as the Secretary of Energy deems appropriate and consistent with applicable law,” identified resources from “leaving the bulk-power system” or converting fuels in such a way that reduces their accredited capacity. An example of fuel conversion that could reduce accredited capacity is replacing a coal-fired power plant with a solar farm.

The language of the E.O. is nonspecific regarding the duration of any DOE action to retain resources or prevent them from leaving the bulk-power system. The E.O. language could be interpreted to mean DOE should take long-term action (i.e., lasting multiple years) or indefinite action. Emergency orders issued in response to multiyear events would be unusual, though not unprecedented, applications of DOE’s Section 202(c) authority. It is unclear the extent to which limits to the authority might exist through judicial review or other avenues if DOE chose to issue long-term or indefinite emergency orders.

DOE issued emergency orders for three separate events in May 2025, all involving seemingly new interpretations of the emergency authority. One event is anticipated electricity supply shortages in Puerto Rico in summer 2025.⁹ One of the DOE emergency orders pertaining to Puerto Rico directs the local utility to conduct vegetation management (e.g., shrub clearing) around specified transmission lines on the island.¹⁰ No other emergency order issued from 2000 to the present has addressed vegetation management.

The other events involve elevated risk of supply shortages in parts of the Midwest and Eastern United States this summer. DOE ordered a delay in retirement plans for a coal-fired power plant in Michigan and a natural gas/oil dual-fired power plant in Pennsylvania.¹¹ Unlike in the cases of other emergency orders issued since 2000, the grid operators in these cases had not requested the delayed retirements. Moreover, neither had identified reliability risks specifically associated with

⁸ Executive Order 14262 of April 8, 2025, “Strengthening the Reliability and Security of the United States Electric Grid,” 90 *Federal Register* 15521-15522, April 14, 2025, <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.

⁹ For background on Puerto Rico’s electricity system, see CRS In Focus IF12913, *Electric Reliability and Resiliency in Puerto Rico*, by Corrie E. Clark.

¹⁰ Secretary of Energy Chris Wright, *Order No. 202-25-2*, May 16, 2025, <https://www.energy.gov/sites/default/files/2025-05/PREPA%20202%28c%29%20Emergency%20Measures%20Transmission.pdf>.

¹¹ Secretary of Energy Chris Wright, *Order No. 202-25-3*, May 23, 2025, https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf; and Secretary of Energy Chris Wright, *Order No. 202-25-4*, May 30, 2025, <https://www.energy.gov/sites/default/files/2025-05/Federal%20Power%20Act%20Section%20202%28c%29%20PJM%20Interconnection.pdf>.

the retirement of the power plants in question at the time they approved those retirements. One of the affected grid operators, PJM, issued a supportive statement following the emergency order.¹²

Issues for Congress

E.O. 14262 does not specify how DOE should streamline its processes for issuing emergency orders. Congress could evaluate whether DOE's existing regulations require streamlining and, if Congress determines they do, could provide policy direction and set a timeline for updating the regulations. Congress could also leave it to DOE's discretion as to when and how to update its regulations.

Congress could weigh DOE action in this space against other priorities for the department, given that updating processes for issuing emergency orders could divert DOE resources from other activities. On the one hand, brownouts or blackouts due to insufficient electricity supplies are relatively rare in the United States. Grid operators have their own processes in place for managing the grid during times of supply shortages and, historically, DOE emergency orders have rarely been requested. On the other hand, many observers anticipate electricity demand to increase in the coming years faster than new supply can be brought online. If these trends continue, brownouts or blackouts could become more common, potentially increasing DOE's use of its emergency authority or Congress's interest in addressing emergency situations for electricity supply.

Regarding the statutory authority itself, Congress could consider whether amendments to Section 202(c) of the Federal Power Act are appropriate. The language has remained unchanged since 1935, potentially reflecting Congress's continued view over this time period that the original authorization is appropriate. Nonetheless, the U.S. electricity system has changed in many ways since 1935, and Congress might choose to consider reevaluating the authority.

One potential aspect for congressional consideration is the duration of DOE emergency orders, especially in relation to critical resources identified pursuant to E.O. 14262. Under current law, and assuming such orders might result in a conflict with environmental requirements, DOE could potentially reissue its emergency orders every 90 days for an indeterminate amount of time. Repeated emergency orders may raise feasibility questions, such as whether successive emergency orders would be upheld by the courts or whether power plant owners would make long-term investments to maintain power plants that are operating primarily under emergency orders.

Congress could consider evaluating and clarifying via legislation whether the Section 202(c) authority is better reserved for short-term situations or whether application to long-term situations is appropriate. Some backers of power plants at risk of retirement (e.g., coal-fired power plants) might support extended emergency orders based on long-term economic considerations. At the same time, some backers of power plants with low greenhouse gas emissions (e.g., solar generators) might support extended emergency orders based on long-term environmental considerations. Others might prefer to limit DOE's emergency authorities to short-term situations. A more limited role for DOE in electricity system operations allows for greater use of market forces and reliance on local- and state-level processes to prepare for and respond to emergencies.

Another potential aspect for congressional consideration is the definition of "emergency" in the context of Section 202(c). Current law gives DOE broad discretion in determining what

¹² PJM, "PJM Statement on the U.S. Department of Energy 202(c) Order of May 30," press release, May 31, 2025, <https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250531-doe-202c-statement-to-defer-retirements-of-certain-generators.pdf>.

constitutes an emergency. Congress could consider whether this level of discretion is appropriate, or whether additional (or alternative) statutory direction would better serve current system needs.

As noted above, some supporters of specific kinds of power plants might view sustained economic conditions or environmental impacts as emergencies that warrant DOE action. Those situations would appear to be novel exercises of DOE authority under Section 202(c), if DOE were to interpret them in such a way. Amendments to the Federal Power Act could clarify congressional intent regarding use of DOE's emergency authority in response to those situations or any other long-term situation.

Other stakeholders might wish to limit DOE's discretion in when to issue emergency orders—for example, by modifying the currently broad statutory language or by requiring additional review by FERC or another entity.

A third potential aspect for congressional consideration is the scope of interventions allowed under the emergency authority. Current law allows DOE to order almost any change in operation of the electricity system.

Emergency orders between 2000 and 2024 directed either the operation of certain generators as needed for reliability or the temporary interconnection of the main Texas grid with neighboring regions' grids. One of DOE's May 2025 emergency orders requires Puerto Rico's local utility to conduct vegetation management activities.

One operational consideration that has not been tested under DOE's emergency authority (at least not in the orders available on DOE's website) is the curtailment of certain generators. Curtailment occurs when a grid operator directs a generator to reduce its output or cease operating altogether for a certain amount of time. Curtailment is sometimes necessary when generation levels in a given location exceed the transmission system's capacity to transmit energy out of that location.

Congress could evaluate the appropriateness of DOE's currently broad discretion to order interventions in the operation of the electricity system. Amendments to the Federal Power Act could clarify what kinds of interventions DOE may require.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-21
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit TT: Department, Order No. 202-26-21 (Mar. 30, 2026)



Department of Energy
Washington, DC 20585

Order No. 202-26-21

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC) Rocky Mountain³ assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig is operated by the Tri-State Generation and Transmission Association (Tri-State). Craig consists of three coal-fired generation units, Unit 1 (446.4 MW), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined name plate capacity of 1427.6 MW.⁴ Unit 1 and Unit 2 are co-owned by Tri-State, Platte River Power Authority, Salt River Project, PacifiCorp, and Public Service Company of Colorado (a subsidiary of Xcel Energy), hereinafter collectively referred to as the “co-owners”.⁵ Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979 respectively. Unit 3 began operations in 1984. Unit 1 was slated to cease operations in December 2025. Unit 2 and Unit 3 are slated to retire in 2028.⁶

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ The 2024 Long-Term Reliability Assessment (LTRA) from the North American Electric Reliability Corporation (NERC) included Colorado in the WECC Northwest assessment area. The 2025 LTRA provides new assessment area boundaries for WECC to provide more geographic detail of reliability risk information and to, “reflect a more accurate alignment with operational and planning realities, as well as the footprints of various entities.” In the 2025 LTRA, Colorado is included in the WECC Rocky Mountain assessment region.

⁴ U.S. Energy Information Administration, *Form EIA-860, Schedule 3: Generator Data* (2024), <https://www.eia.gov/electricity/data/eia860/>.

⁵ Platte River Power Authority, Craig Units 1 & 2 (Yampa Project), <https://prpa.org/generation/yampa-project/>.

⁶ As a coal-fired facility, it would be difficult for the Craig Unit 1 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as

Order No. 202-25-14, issued pursuant to FPA section 202(c) on December 30, 2025, required that Tri-State and the co-owners take all measures necessary to ensure that Craig Unit 1 continues to be available to operate for 90 days, until March 30, 2026. This order was based on my determination that emergency conditions existed within the WECC Northwest assessment area.

Specifically, I determined that the WECC Northwest assessment area faced significant amount of retiring baseload generation resources and concerns meeting demand during shoulder periods.⁷ I determined that the continued availability of Craig Unit 1 would provide additional generation capacity, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.⁸ I determined that the continued availability of Craig Unit 1 was necessary to alleviate immediate and anticipated threats to reliability.⁹ My determination was based on several facts.

First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that in the WECC Northwest assessment area, which included Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, “[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio.” The 2024 LTRA notes that:

[f]ive [gigawatts] of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and [battery energy storage systems], further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of [battery energy storage systems] resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.¹⁰

employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Tri-State and co-owners were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

⁷ See, e.g., *Tri-State Generation and Transmission Association (Tri-State), Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy*, Order No. 202-25-14, at 1–2 (Dec. 30, 2025).

⁸ See, e.g., *id.* at 1–3.

⁹ See, e.g., *id.* at 3.

¹⁰ NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024, corrected Jul. 11, 2025), at 130 (Dec. 2024, corrected Jul. 11, 2025), https://www.nerc.com/globalassets/ourwork/assessments/2024-ltra_corrected_july_2025.pdf.

Second, the 2024 WECC Western Assessment of Resource Adequacy notes that peak demand in WECC’s Northwest-Central subregion, which included Colorado at the time, is “forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034.”¹¹ Meanwhile, WECC notes that most planned retirements are “baseload generation, such as coal, natural gas, and nuclear.”¹²

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-25-14 continue, both in the near and long term.¹³ The availability of electricity from Craig Unit 1 will continue to be critical to maintain reliability in the WECC Rocky Mountain assessment area.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.¹⁴ While NERC assessed that the WECC Rocky Mountain region, which includes Colorado, is at normal risk of energy shortfalls over the next five years,¹⁵ the area has an “[anticipated reserve margin] that falls below the [Reference Margin Level] in Summer 2034 and 2035, and Winter 2034–35.”¹⁶ The LTRA also notes that the WECC-Rocky Mountain assessment area faces challenges from an aging thermal resource fleet, which can lead to unplanned outages, exacerbated by supply chain issues, and vendor availability.¹⁷ Additionally, both solar and wind variability are year-round concerns, and while the region is pursuing advancement into Regional Transmission Organizations (RTOs) to leverage a wider footprint, smaller entities currently have limited geographic diversity to counteract these generation constraints.¹⁸

The 2025 WECC Western Assessment of Resource Adequacy notes that “the West’s planned resource buildout will not keep up with anticipated load growth over the next decade, particularly in the Basin and Northwest subregions. The West could see

¹¹ WECC, *Western Assessment of Resource Adequacy 2024: Peak Demand by Subregion*, at 2, <https://www.wecc.org/sites/default/files/documents/products/2024/WARA%202024%20Peak%20Demand%20by%20Subregion.pdf>.

¹² WECC, *Western Assessment of Resource Adequacy*, <https://feature.wecc.org/wara/>.

¹³ Further, as noted in Order No. 202-25-14, as a coal-fired facility, it would be difficult for Craig Unit 1 to resume operations once it has been retired. See Order No. 202-25-14 at 1.

¹⁴ NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

¹⁵ *Id.* at 7.

¹⁶ *Id.* at 160.

¹⁷ *Id.* at 161.

¹⁸ *Id.*

energy shortfalls as early as 2028.”¹⁹ The assessment goes on to say that “[i]f resources are added as planned, loss of load may be limited to the Basin and Northwest subregions. However, if planned resource additions are delayed or cancelled, other subregions could also be at risk.”²⁰ Further, the assessment highlights that 90% of planned resources over the next decade are inverter-based resources, which “continue the rapid evolution of the resource mix away from traditional dispatchable resources to more weather-dependent resources.”²¹

Since 2019, the retirement of coal-fired generating capacity in Colorado has led to a decline in the share of coal-generated electricity from 45% to 25%.²² Looking forward, by 2029, about 3,700 megawatts (MW) of coal-fired generating capacity in Colorado is scheduled to retire according to the Energy Information Administration (EIA),²³ accounting for all but one coal-fired power plant in Colorado. In that same time frame, 620 MW of natural gas-fired generating capacity in Colorado will retire as well.²⁴ In 2025, intermittent wind accounted for over 5,300 MW of Colorado’s electricity generating capacity.²⁵ Additionally, Colorado Public Utilities Commissioners

¹⁹ WECC, *Western Assessment of Resource Adequacy*, <https://feature.wecc.org/2025wara/index.html>.

²⁰ *Id.*

²¹ *Id.*

²² U.S. Energy Information Administration, *Electricity Data Browser, Net Generation for All Sectors Annually from 2019-2025, State: Colorado*, (last accessed Mar. 18, 2026), <https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvp&geo=0000000000g&sec=g&freq=A&start=2019&end=2024&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0>.

²³ U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Conventional Steam Coal* (Jan. 2026), <https://www.eia.gov/electricity/data/eia860m/>.

²⁴ U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Natural Gas Fired Combustion Turbine and Natural Gas Stream Turbine* (Jan. 2026), <https://www.eia.gov/electricity/data/eia860m/>.

²⁵ U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colorado, Technology: Onshore Wind Turbine* (Jan. 2026), <https://www.eia.gov/electricity/data/eia860m/>.

have expressed concerns about the ability of certain utilities to meet projected summer 2026 loads.²⁶

Order No. 202-25-14 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”²⁷ The Executive Order adds, “hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”²⁸ In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”²⁹

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”³⁰ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

²⁶ RTO Insider, *Comanche 3 Repair Delay Raises RA Concerns in Colorado*, (March 26, 2026), <https://www.rtoinsider.com/129021-comanche-3-repair-delay-raises-ra-concerns-in-colorado/>.

²⁷ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

²⁸ *Id.*

²⁹ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

³⁰ U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest.”³¹ This statutory language constitutes a specific grant of authority to the Secretary to require the availability and operation of Craig Unit 1 when the Secretary has determined that such availability and operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Craig Unit 1 shall be made available for operation through June 28, 2026.

Based on my determination of an emergency set forth above, I hereby order:

- A. For March 31, 2026, Tri-State and the co-owners, shall take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region, Western Area Colorado Missouri (WACM), in its role as Balancing Authority,³² or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator,³³ as applicable.
- B. From April 1, 2026, SPP, Tri-State and the co-owners shall take all measures

³¹ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

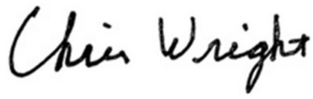
³² See EIA-930A 2024 Data, <https://www.eia.gov/electricity/gridmonitor/about>. On EIA-930A 2024 SCH 2, the balancing authority (BA) Code for Craig is WACM. See EIA-930 data reference tables, <https://www.eia.gov/electricity/gridmonitor/about>. On EIA-930 data reference tables BA Code WACM is associated with Western Area Power Administration—Rocky Mountain Region.

³³ SPP, *Western RC Services*, [https://www.spp.org/western-services/western-rc-services/#:~:text=SPP%20is%20a%20certified%20Reliability%20Coordinator%20\(RC\),Interchange%20Tool%20*%20Western%20Interconnection%20Synchrophasor%20Project](https://www.spp.org/western-services/western-rc-services/#:~:text=SPP%20is%20a%20certified%20Reliability%20Coordinator%20(RC),Interchange%20Tool%20*%20Western%20Interconnection%20Synchrophasor%20Project).

- necessary to ensure that Craig Unit 1 is available to operate.³⁴ For the duration of this Order, SPP is directed to take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Tri-State and the co-owners are directed to comply with all orders from SPP related to the availability and dispatch of Craig Unit 1.
- C. To minimize adverse environmental impacts, this Order limits operation of Craig Unit 1 to the times and within the parameters established in paragraph A and paragraph B. SPP and Tri-State shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Craig Unit 1 has operated in compliance with this Order.
 - D. All operations of Craig Unit 1 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.
 - E. By April 14, 2026, SPP and Tri-State, in coordination with the co-owners, are directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures each has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with this Order. SPP, Tri-State and the co-owners shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
 - F. Tri-state and the co-owners are directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
 - G. This Order shall not preclude the need for Craig Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
 - H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Craig Unit 1 shall not be considered a capacity resource.
 - I. This Order shall be effective from March 31, 2026 through June 28, 2026, with the exception of applicable compliance obligations in paragraph E.

³⁴ WAPA, *Southwest Power Pool RTO Membership Initiative*, <https://www.wapa.gov/about-wapa/the-source/key-topics/southwest-power-pool-membership/#:~:text=Since%202020%2C%20WAPA's%20Colorado%20River,FERC%20website%20under%20Docket%20No.>

Issued in Washington, D.C. on this 30th day of March 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Colorado Public Utilities Commission
Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-21
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit U: Department, Order 202-25-9 (Nov. 18, 2025)



Department of Energy
Washington, DC 20585

Order No. 202-25-9

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order Nos. 202-25-3 and 202-25-7

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a “speed closure” of the Campbell Plant fifteen years before the end of its scheduled design life.³ Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant’s retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. Subsequently, Order No. 202-25-7, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until November 19, 2025. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. §7151(b).

³ See *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan’s Clean Energy Transformation*, Consumers Energy (June 23, 2021), <https://www.consumersenergy.com/news-releases/newsrelease-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-cleanenergy-transformation>.

Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that “[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.”⁴ In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.⁵

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), “[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned.”⁶ Additionally, EIA stated, “[t]ypically, Michigan’s nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned.”⁷ The state’s Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although according to a recent news report, “Holtec International expects the Palisades plant in Michigan to resume service early next year....”⁸

Third, the Campbell Plant’s retirement would have further decreased available dispatchable generation within MISO’s service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates “elevated risk of operating reserve shortfalls.”⁹

Fourth, MISO’s Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.”¹⁰ While the results “demonstrated sufficient

⁴ 2025 Summer Reliability Assessment, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

⁵ *Id.*

⁶ *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), <https://www.eia.gov/state/print.php?sid=MI>.

⁷ *Id.*

⁸ *Nuclear plants face decadelong timeline to meet AI energy needs*, Los Angeles Times. (Nov. 13, 2025), <https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs>.

⁹ NERC 2025 Summer Reliability Assessment at 16.

¹⁰ *Planning Resource Auction—Results for Planning Year 2025–2026*, Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).

capacity,” the summer months reflected the “highest risk and a tighter supply-demand balance” and these results “reinforce the need to increase capacity.”¹¹

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order Nos. 202-25-3 and 202-25-7 continue, both in the near and long term.¹² The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the U.S. Environmental Protection Agency’s data, the plant has generated an average of approximately 509,000 MWh per month, from June 2025 through September 2025,¹³ providing vital generation capacity to the region. Additionally, between June 11 and November 5, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.

MISO’s year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.¹⁴ MISO justified this revision by explaining that “Reliability risks associated with resource adequacy have shifted from ‘Summer only’ to a year-round concern.”¹⁵ MISO noted that over 60% of all “MaxGen” events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.¹⁶

In December of 2023, MISO released an “Attributes Roadmap,” in which it presented “an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape.”¹⁷ Among other things, this report described changes in the time of year during

¹¹ *Id.* at 2,12. For further information regarding the determination that emergency conditions existed, see Order No. 202-25-7.

¹² Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

¹³ See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data), <https://campd.epa.gov/data/custom-data-download> (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >> “2025” and “June, July, August, September.” The data can then be filtered to only include the JH Campbell Plant.)

¹⁴ Midcontinent Independent System Operator, Inc., FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

¹⁵ MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

¹⁶ *Id.* at 3-4.

¹⁷ *Attributes Roadmap*, MISO (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>

which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.¹⁸

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, “*MISO’s Response to the Reliability Imperative*.”¹⁹ In a section of that report entitled “Risks in Non-Summer Seasons,” MISO again stressed that it has resource reliability concerns outside of the summer season.

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region’s highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.²⁰

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

While the 2025 – 2026 NERC Winter Reliability Assessment has not yet been released as of the date of this Order, two recent winter studies (2024 – 2025 NERC Winter Reliability Assessment²¹ and the 2023 – 2024 NERC Winter Reliability Assessment²²) have assessed the MISO assessment area as an elevated risk, with the “potential for insufficient operating reserves in above-normal conditions.” Specifically, the 2024 – 2025 Winter Reliability Assessment noted that “[ge]nerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO’s capacity market, or received lower winter accredited capacity.”²³

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that “new capacity additions were insufficient to offset the negative impacts of decreased

¹⁸ *Id.* at 11.

¹⁹ *MISO’s Response to the Reliability Imperative*, MISO (Updated Feb. 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>

²⁰ *Id.* at 12.

²¹ 2024 – 2025 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

²² 2023 – 2024 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf

²³ 2024 – 2025 NERC Winter Reliability Assessment at 15, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Michigan.²⁴

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.²⁵ The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.²⁶ The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.²⁷ Similar results were projected for MISO’s winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.²⁸

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.²⁹ Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.³⁰

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.³¹ The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.³² In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are

²⁴ MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

²⁵ *OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>

²⁶ *Id.* at 2.

²⁷ *Id.* at 7.

²⁸ *Id.* at 9

²⁹ *Id.* at 7, 9.

³⁰ *Id.*

³¹ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

³² 192 FERC ¶ 61,064 at P 84.

likely to further hinder rapid construction and exacerbate reliability concerns.³³ Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3 and 202-25-7 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid,” President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”³⁴ President Trump likewise recognized, in Executive Order 14156, “Declaring a National Energy Emergency,” that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”³⁵ The Executive Order adds: “Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”³⁶

The Department’s July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President’s directive in Executive Order 14262, details the myriad challenges affecting the Nation’s energy outlook. “Absent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”³⁷ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.³⁸ In addition, as just one example,

³³ See generally, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), [US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global](https://www.spglobal.com/commodityinsights/enews/US-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply). “With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts.”

³⁴ Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

³⁵ Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

³⁶ *Id.*

³⁷ See also *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

³⁸ Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), <https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan>.

Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and “continue[s] to see positive momentum with data centers within the 9 GW pipeline”³⁹

Grid operators — including MISO itself — have also acknowledged the Nation’s current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that “the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth.”⁴⁰ Ms. Curran also described “much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence.”⁴¹ She added, “[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them.”⁴²

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”⁴³ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has

³⁹ See *Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), <https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-toprovide-1gw-of-power-to-new-hyperscale-data-center/> (quoting Consumers Energy CEO Garrick Rochow).

⁴⁰ Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-mediadocument/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf

⁴¹ *Id.* at 6.

⁴² *Id.* at 7.

⁴³ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3 and 202-25-7 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand and determined shortage and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until February 17, 2026.⁴⁴

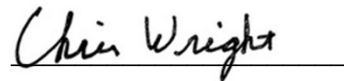
Based on my determination of an emergency set forth above, I hereby order:

- A. From November 19, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.
- C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

⁴⁴ 16 U.S.C. § 824a(c)(4).

- D. By December 3, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.
- H. This Order shall be effective from 00:00 Eastern Standard Time (EST) on November 19, 2025, and shall expire at 00:00 EST on February 17, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 5:58PM EST on this 18th day of November 2025.



Chris Wright
Secretary of Energy

cc:

FERC Commissioners

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Michigan Public Service Commissioners

Chairman Dan Scripps

Commissioner Katherine Peretick

Commissioner Shaquila Myers

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Craig Unit 1

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)
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Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit UU: Tri-State, Request for Clarification and for Rehearing of Tri-State
Generation and Transmission Association and Platte River Power Authority
(Jan. 29, 2026)

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January 29, 2026

Via Email

Secretary Chris Wright
U.S. Department of Energy
1000 Independence Ave., SW
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Alex Fitzsimmons, Director
Office of Cybersecurity, Energy Security, and
Emergency Response
1000 Independence Avenue, SW
Washington, DC 20585

Re: Craig Station, Order No. 202-25-7

Dear Secretary Wright and Mr. Fitzsimmons:

Pursuant to Section 313(a) of the Federal Power Act,¹ and Section 301(b) of the Department of Energy Organization Act,² Tri-State Generation and Transmission Association, Inc., and Platte River Power Authority hereby submit for filing the enclosed request for rehearing and for clarification.

Please contact me if you have any questions.

Respectfully submitted,

/s/ Jennifer Quinn-Barabanov

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¹ 16 U.S.C. § 825l(a).

² 42 U.S.C. § 7151(b).

**UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY**

In re Craig Order No. 202-25-14

) Order No. 202-25-14
)

**REQUEST FOR CLARIFICATION AND FOR REHEARING OF TRI-STATE
GENERATION AND TRANSMISSION ASSOCIATION AND PLATTE RIVER
POWER AUTHORITY**

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Pursuant to Section 313(a) of the Federal Power Act,¹ and Rule 713 of the Rules and Regulations of the Federal Energy Regulatory Commission (FERC or Commission),² and the applicable rules of practice and procedure,³ Tri-State Generation and Transmission Association, Inc. (Tri-State) and Platte River Power Authority (Platte River) (together, Petitioners) hereby file this Request for Clarification and Rehearing of the Order No. 202-25-14 dated December 30, 2025 (the Order) requiring Petitioners and their co-owners to keep coal-fired Unit 1 of the Craig Generating Station in Craig, Colorado (Craig Unit 1) open and available to operate. Craig Unit 1 was scheduled to shut down by December 31, 2025.⁴

SUMMARY

Petitioners and the Department of Energy (DOE) share the goal of securing reliable and affordable electricity generation assets for their service areas' energy grid, including in the event of an energy emergency. For years, Petitioners have engaged in thorough, deliberate, and industry-leading resource planning to achieve this same end. Petitioners' resource planning ensures that the communities they serve are supported by electricity generation resources sufficient to respond to

¹ 16 U.S.C. § 8251.

² 18 C.F.R. § 385.713 (2024).

³ U.S. Dep't of Energy, DOE Rehearing Procedures, <https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures> (last visited Jan. 15, 2026); *see also* 18 C.F.R. §§ 385.214, 385.713.

⁴ Petitioners are co-owners of Craig Unit 1, and named recipients of the Order. Under the Commission's rules and regulations they are parties to this proceeding. However, if necessary to give them party status, out of an abundance of caution, Petitioners ask that this filing also be treated as a motion to intervene under Rule 214 of the Commission's Rules and Regulations. Petitioners' position on the Order and the nature of their interest are set forth in detail in this filing.

forecasted extreme weather events and demand growth, relying on coal, gas, dual-fuel, hydropower, solar, wind, and battery assets.

Petitioners will continue to work with DOE and other government agencies to secure reliable, affordable generation portfolios, but submit this request for clarification and rehearing because keeping Craig Unit 1 available to operate will not best meet DOE's goal of securing dispatchable electricity resources in the northwestern United States. Tri-State and Platte River, as member-owned and municipal public utilities, respectively, face unique challenges from the DOE's Order that lead them to file this request. The costs of compliance fall directly on their members and customers, who must now pay to respond to the DOE's finding that utilities in the northwestern United States have "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes," DOE Order No. 202-25-14 at 1 (Dec. 30, 2025). The members and customers must pay those costs even though neither Tri-State nor Platte River are experiencing these shortages and not all the members and customers served by Tri-State and Platte River are located in the region identified by the Order. For example, Tri-State has numerous members in New Mexico and Nebraska. Petitioners have already paid for and planned investments in the generation resources needed to secure reliable and sufficient capacity for their systems. The Order therefore imposes additional costs to Tri-State's membership and the communities served by Platte River.

Petitioners respectfully ask DOE to reconsider the Order and to work with Petitioners to find a more effective and affordable path forward, one that will not

delay retirement of Craig Unit 1. Petitioners continue to stand ready, willing, and able to work cooperatively with DOE and any other federal agencies to address energy emergencies in a manner that minimizes costs, promotes reliability, and complies with the law.

STATEMENT OF ISSUES

Pursuant to Section 313(a), Petitioners request clarification and, in the alternative, rehearing based upon the following issues:

1. By mandating Craig Unit 1's availability to operate and the terms under which it shall operate, and requiring related changes to Petitioners' physical property, the Order constitutes both a physical taking and a regulatory taking. Because the Order does not provide "just compensation" from the government, this is an uncompensated taking in violation of the Fifth Amendment to the United States Constitution. *United States v. Pewee Coal Co.*, 341 U.S. 114, 116 (1951); *Horne v. Dep't of Agric.*, 576 U.S. 351 (2015); *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1011 (1984).
2. Because DOE predicated the Order on long-term concerns, Petitioners were deprived of the process due to them pursuant to the Administrative Procedure Act (APA) and the Federal Power Act (FPA), and the Fifth Amendment to the United States Constitution. This constitutes a violation of Petitioners' due process rights as guaranteed by the Fifth Amendment. *Miller v. Campbell Cnty.*, 945 F.2d 348, 353 (10th Cir. 1991); *Pa. Gas & Water Co. v. FPC*, 427 F.2d 568, 576 (D.C. Cir. 1970).
3. There is a disconnect between the energy reliability concerns described by the Order and the means DOE directs for addressing those concerns as compared to alternatives. DOE, therefore, did not establish that the Order "best meet[s] the emergency and serve[s] the public interest." 16 U.S.C. § 824a(c); 10 C.F.R. § 205.373. It is, therefore, arbitrary and capricious.
4. The Order does not align with the statutory objectives of the Federal Power Act (FPA), because it requires the operation of an uneconomic resource and disrupts ordinary and orderly planning, development, and investment in generation resources. It is, therefore, arbitrary and capricious.

BACKGROUND

A. The Petitioners

Tri-State is a wholesale generation and transmission cooperative operating on a not-for-profit basis with its principal place of business in Westminster, Colorado. Organized and existing pursuant to the Colorado Cooperative Act,⁵ Tri-State is a public utility subject to FERC jurisdiction under Part II of the FPA.⁶ Tri-State is wholly owned by its electric distribution cooperative and public power district members (Utility Members) and three non-Utility Members (Non-Utility Members)⁷ and was formed by its Utility Members for the purpose of providing the Utility Members with wholesale power and transmission services for resale to their retail customers.

Through their participation in the cooperative, the Utility Members serve retail customers across Wyoming, Nebraska, New Mexico, and Colorado. Some, but not all, of the Utility Members and their retail customers are located in the 2024 Western Electricity Coordinating Council (WECC) Northwest region.⁸ The retail service territories of Tri-State's Utility Members cover approximately 182,000 square miles and their customers include suburban and rural residences, farms and ranches,

⁵ COLO. REV. STAT. § 7-55-101 *et seq.* (2019) (Cooperatives- General); Articles of Incorporation (2020).

⁶ *Tri-State Generation and Transmission Ass'n*, 170 FERC ¶ 61,221, at P 37 (2020).

⁷ Tri-State's Non-Utility Members are: (i) MIECO, Inc., a wholesale supplier of natural gas in the United States; (ii) Olson's Greenhouses of Colorado, LLC, a grower/distributor of plants throughout the western United States that has a contract to purchase thermal energy from Tri-State; and (iii) Ellgen Ranch Company, which leases property from a Tri-State subsidiary.

⁸ The boundaries of this region changed from 2024 to 2025, *see* note 24, *infra*.

and large and small businesses and industries, serving approximately 522,000 retail electric meters. Tri-State's Utility Members are the sole state-certified providers of electric service to retail (residential and business) customers within their designated service territories.

Tri-State owns, directly or indirectly, or controls the output of, various power generation facilities within the Western Area Power Administration's (WAPA) Western Area Colorado Missouri (WACM) balancing authority area, and purchases wholesale power within both the Western and Eastern Interconnections. Among other generation facilities, Tri-State is a partial owner of Craig Unit 1, with a 24% ownership share. Tri-State's generating facilities are included in the Western Power Pool reserve sharing pool. This pool facilitates sharing of generation reserves to be activated during a system emergency, such as loss of a generating unit or transmission line. Tri-State expects to participate in the Southwest Power Pool's (SPP) regional transmission organization, with respect to Tri-State's service in the WACM balancing authority area within the Western Interconnection, beginning in April 2026.

Platte River is a not-for-profit, municipally-owned power utility and joint action agency that generates reliable, financially sustainable, and environmentally responsible electricity for its owner communities of Estes Park, Fort Collins, Longmont, and Loveland, Colorado. Platte River is a political subdivision of the State of Colorado and a government-owned utility under FPA Section 201(f), 16 U.S.C.

§ 824(f). Platte River furnishes cost-of-service wholesale electrical power and energy to its four owner communities.

Platte River is headquartered in Fort Collins, Colorado. At Platte River's main generating facility, Rawhide Energy Station, Platte River has one coal-fired power plant, Unit 1, with a nameplate capacity of 280 megawatts (MW), as well as five natural gas-fired units with a total capacity of 388 MW. Platte River also purchases 297 MW of wind energy and 202 MW of solar energy through long-term power purchase agreements and is a preference customer of WAPA's Colorado River Storage Project and Loveland Area Projects, providing up to 78 MW of hydropower. Platte River is a partial owner of two additional coal-fired units, Craig Units 1 and 2, with an 18% ownership share in the Craig units. Platte River's share of the total net capacity from both Craig units is 151 MW. Platte River also owns and operates an integrated transmission system of high-voltage aerial and underground power lines that deliver electricity to the electric utilities of Platte River's owner communities in Northern Colorado. Like Tri-State, Platte River plans to participate in SPP's regional transmission organization beginning in April 2026.

B. The Craig Generating Station

Craig Generating Station is a three-unit, coal-fired power plant located in Craig, Colorado. Craig Units 1 and 2 were built by and are jointly owned by several utilities through what is known as the Yampa Project. Tri-State operates those two units on behalf of all the co-owners, including Platte River, PacifiCorp, Public Service Company of Colorado, and Salt River Project. Tri-State separately owns and operates

Craig Unit 3. Together, these units are transmission-interconnected to the broader power grid and supply electricity into Western energy markets.

As part of its resource plan to address the long-planned retirement of Craig Unit 1, Tri-State has placed into service the 145 MW Axial Basin generating facility. This facility, approximately 26 miles from the Craig facility, relies on much of the same transmission infrastructure. Absent the retirement of Craig Unit 1, this interconnection faces transmission constraints such that, when Craig Unit 1 remains interconnected and available to operate, Tri-State may be required to curtail output from Axial Basin when all facilities are generating at or near full output due to limited transmission capacity.

As a result of changed market conditions and state and federal requirements, Unit 1 has been scheduled for retirement since 2016, and Units 2 and 3 have been scheduled for retirement since 2020, beginning with Craig Unit 1 by December 31, 2025, followed by Craig Unit 3 by January 1, 2028, and Craig Unit 2 by September 30, 2028. A retirement date for each Craig unit is now specified in Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits.⁹ In 2016, Craig Unit 1's retirement date was adopted into what was then Colorado Air Quality Control Commission Regulation No. 3 on Stationary Source Permitting and Air Pollutant Emission Notice Requirements and the Regional Haze State Implementation Plan, the latter of which was approved by EPA in 2018.¹⁰

⁹ COLO. CODE REGS. 1001-27.

¹⁰ *See Approval and Promulgation of Implementation Plans; Colorado; Regional Haze 5-Year Progress Report State Implementation Plan*, 84 Fed. Reg. 47884 (Sept. 11, 2019); Co. Air Pollution

The Craig units have been fueled primarily by coal from the nearby Colowyo and Trapper mines. The Colowyo Mine has ceased active mining and transitioned to full reclamation, with two pits in final reclamation and the third transitioned to reclamation on October 15, 2025. Similarly, the Trapper Mine plans to cease active mining and convert to site remediation in calendar year 2026. Before the closure of the Colowyo Mine, Tri-State stockpiled sufficient coal to meet Tri-State's projected demand of the Craig Units 2 and 3 through their respective planned retirement dates. Before the Trapper Mine closes, Platte River will have stockpiled sufficient coal to meet its projected demand of the Craig Unit 2 through its planned retirement date.

C. Craig Unit 1

Craig Unit 1 can produce up to 427 MW of electricity and has been running since 1980. Over the last ten years, the operations and maintenance cost (without consideration of coal cost or depreciation expense) to run Craig Unit 1 has averaged \$12.99 million annually.¹¹ By the standards of an older coal plant, Craig Unit 1 has generally provided reliable performance when called upon. However, in the last three years (due primarily to economic factors and some forced outages), Craig Unit 1 has run well below half of its capacity for Petitioners.

Control Div., *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016), <https://oitco.hylandcloud.com/POP/DocPop/DocPop.aspx?docid=3303135>.

¹¹ Over the last ten years, the operations and maintenance cost to run Tri-State's share of Craig Unit 1 has averaged \$23.9 million annually (inclusive of coal cost and depreciation expense). Over the last ten years, the fixed operations and maintenance cost to run Platte River's share of Craig Unit 1 has averaged roughly \$2.3 million (exclusive of coal cost and depreciation expense) annually.

Operation and maintenance of Craig Unit 1 has been undertaken prudently to reflect the scheduled 2025 retirement. The Craig Unit 1 owners have deferred optional maintenance since 2019. Craig Unit 1 has had multiple breakdowns and required significant repairs to continue operating into 2025. On December 19, 2025, the unit suffered a valve failure that rendered Craig Unit 1 inoperable, although the unit is now available to operate following repairs made in direct response to the Order.¹²

D. DOE Order No. 202-25-14

On December 30, 2025, DOE issued Order No. 202-25-14. The Order declared that “an emergency exists within the WECC-NW assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes.” DOE Order No. 202-25-14 at 1 (Dec. 30, 2025). The Order predicated its emergency on (1) “increasing demand” and (2) “shortage from accelerated retirement of generation facilities [that] will continue in the near term and are also likely to continue in subsequent years.” DOE stated, “[t]his could lead to the loss of power to homes, and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.” *Id.* at 3.

DOE predicated energy reliability concerns on the 2024 Long-Term Reliability Assessment (2024 LTRA) from the North American Electric Reliability Corporation (NERC) for the WECC-NW assessment area, “which includes Colorado, Idaho,

¹² Tri-State Generation & Transmission Ass’n, Inc., *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating Next 90 Days*, TRI-STATE (Dec. 31, 2025), <https://tristate.coop/us-doe-orders-tri-state-keep-craig-generating-station-unit-operating-next-90-days>.

Montana, Oregon, Utah, Washington, and Wyoming[.]” *Id.* at 1. DOE also pointed to the 2024 WECC Western Assessment of Resource Adequacy. The concerns included (1) greater “energy variability” due to the region’s use of wind and hydropower; (2) planned retirement of baseload generation facilities fueled by coal, natural gas and nuclear; and (3) projected regional load growth. *Id.* at 2.¹³

The Order required Tri-State and the other co-owners of Craig Unit 1 to:

1. Take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, as applicable;
2. Limit operation of Craig Unit 1 to the times and within certain parameters to minimize adverse environmental impacts;
3. Provide daily notification to DOE reporting whether Craig Unit 1 has operated in compliance with the Order;
4. Comply with applicable environmental requirements including, but not limited to, monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions;
5. Update DOE on measures taken or planned to ensure operational availability of Craig Unit 1 by January 20, 2026; and
6. File with the FERC Tariff revisions or waivers to effectuate the Order with rate recovery available pursuant to 16 U.S.C. § 824a(c).

Tri-State has already taken and will continue to take steps to comply with the Order. In coordination with the other co-owners of Unit 1, it timely submitted its

¹³ The Order placed these concerns in the broader context of Executive Orders 14156 and 14262. Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency>; Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.

update to DOE on January 20, 2026, describing the measures it has taken and plans to take to ensure operational availability of Craig Unit 1. Tri-State has submitted and continues to submit daily notification to DOE pursuant to the Order.

ARGUMENT

Petitioners seek rehearing and clarification on two fronts. *First*, the Order, as drafted, effectuates a taking of Petitioners' property under the Fifth Amendment to the United States Constitution without an adequate process to obtain constitutionally required compensation. *Second*, the Order does not meet Section 202(c)'s requirement for a reasoned finding that compels operation of Craig Unit 1 as the "best" solution to the identified emergency.

I. THE ORDER CONSTITUTES AN UNCOMPENSATED TAKING OF PETITIONERS' PROPERTY INTERESTS

Petitioners chose to close Craig Unit 1 largely because of the uneconomic nature of the facility, and Petitioners have taken numerous steps over the years to prepare for its closure. By mandating that Tri-State continue operating the facility on a sustained basis for months beyond its planned closure date, and thus directing its operations in a manner entirely inconsistent with Petitioners' own planned retirement of the facility, the Order effects an uncompensated taking of Petitioners' property in violation of the Fifth Amendment of the United States Constitution. By compelling continued operational availability of Craig Unit 1, DOE took effective control over the physical infrastructure of the facility and mandated a variety of changes to Petitioners' infrastructure and business operations, constituting both a *per se* physical and regulatory taking.

A taking is not prohibited so long as it provides just compensation, but this taking comes with no assured government compensation. FERC cost recovery shifts costs onto ratepayers; it does not assure compensation *from the government*. And, due in part to the broad scope of the declared energy emergency, FERC cost recovery related to the Order will be complex procedurally and substantively and could leave material costs unrecovered from the Order’s putative beneficiaries. The Order gives Petitioners no constitutionally adequate avenue for just compensation.

A. The Order Constitutes a Physical Taking

The Fifth Amendment provides, “private property [shall not] be taken for public use, without just compensation.” U.S. Const. amend. V. “When the government physically acquires private property for a public use, the Takings Clause imposes a clear and categorical obligation to provide the owner with just compensation.” *Cedar Point Nursery v. Hassid*, 594 U.S. 139, 147 (2021) (citation omitted).

Physical takings can take a variety of forms, including intermittent or limited-value intrusions. *Id.* at 149–55; *see also Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419 (1982). Moreover, “[i]f government action would qualify as a taking when permanently continued, temporary actions of the same character may also qualify as a taking.” *Ark. Game & Fish Comm’n v. United States*, 568 U.S. 23, 26 (2012). This is true even when the government has not seized title to a property but rather directed it to operate in a particular way. Temporary seizures of property to operate are takings in “as complete a sense as if the Government held full title and ownership.” *See Pewee Coal Co.*, 341 U.S. at 116 (quoting *United States v. United Mine Workers of Am.*, 330 U.S. 258, 285–86 (1947)).

The Order operates as a physical taking in two interrelated ways. *First*, by directing Petitioners to maintain and operate Craig Unit 1, on a prolonged basis,¹⁴ and in clear departure from Petitioners’ own planned retirement of the facility, the Order falls within a near-century-old tradition of classifying mandatory operations—even under wartime and emergency authorities—as takings that must be compensated. *Second*, even if not characterized as a government seizure of operations, the Order constitutes a physical taking by compelling Petitioners to make material physical changes to the plant, including repairing out-of-service equipment, requiring staff onsite, and physically diverting coal allocated for Craig Units 2 and/or 3 to fuel Craig Unit 1 as the facility’s operations deplete limited fuel reserves that were allocated to other units that remain operational and are needed for reliability—the depletion of these stockpiled reserves will require Petitioners to obtain replacement coal at uncertain future prices, creating an additional uncompensated cost. And because of transmission constraints, Craig Unit 1’s operations could further impede Tri-State’s use of the nearby Axial Basin generating facility by constraining Tri-State’s ability to inject power from that facility onto the grid.

¹⁴ Petitioners note that other similar Section 202(c) orders, issued to other utilities and on similar grounds, have been repeatedly renewed. *See, e.g.*, DOE Order No. 202-25-3 (May 23, 2025), *renewed for 90 days by* DOE Order No. 202-25-7 (Aug. 20, 2025), *renewed for 90 days by* DOE Order No. 202-25-9 (Nov. 18, 2025). Petitioners are reasonably concerned that DOE Order No. 202-25-14 could be similarly repeatedly renewed.

1. The Order's Direction of Prolonged Operations at Craig Unit 1 Contrary to Petitioners' Plan to Retire the Facility Constitutes a Physical Taking

Section 202(c) was enacted to address energy shortages that occurred during the First World War,¹⁵ making it particularly suitable for analysis under post-war interpretations of the Takings Clause. These cases show that, even in the context of an emergency, where the government takes control of part or all of a business's facilities to use and operate for the government's purposes, a compensable taking occurs, *see, e.g., United States v. Gen. Motors Corp.*, 323 U.S. 373 (1945) (holding that a government seizure of part of a leased warehouse space for military purposes was a compensable taking). Similarly, where the government requires a private business to operate in the public interest, this too constitutes a *per se* physical taking. *Pewee Coal Co.*, 341 U.S. at 116 (taking occurred when government responded to work stoppages and strikes at coal mines by directly operating them or arranging for their continued operation). Finally, these cases illustrate that a taking is particularly likely to occur where the imposition of government control extends over a lengthy period of time. *See Gen. Motors Corp.*, 323 U.S. at 375 (warehouse seized for more than a year); *Pewee Coal Co.*, 341 U.S. at 115 (government-directed operation of coal mine continued for more than 160 days).

In that light, the Order constitutes a taking of Petitioners' property. The Order requires Petitioners to, in relevant part: (1) take all measures necessary to ensure that Craig Unit 1 is available to operate; and (2) limit operation of Craig Unit 1 to

¹⁵ Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 789–846, 800–02 (2024) (hereinafter “Rolsma (2024)”).

certain times and parameters to minimize adverse environmental impacts. Even the narrowest version of the measures necessary to ensure that Craig Unit 1 is available to operate include extensive repairs to Craig Unit 1’s physical facility and the ongoing employment of some share of approximately 130 staff to maintain the Craig facility, operate equipment, and remain ready to operate. The Order requires Petitioners to take these significant steps, unnecessary but-for the Order, for a prolonged period of time. This closely resembles the sustained mandate to operate that the *Pewee Coal* Court held was a taking.¹⁶

Indeed, the federal government recently recognized that where the government appropriates the right to control operation of a facility and deprives owners of their freedom to dispose of their property, a taking has occurred. *See* EPA-R08-OAR-2024-0607-0067, Regional Haze Round 2 at 19–21 (Jan 9, 2026), <https://www.regulations.gov/document/EPA-R08-OAR-2024-0607-0067> (describing how the “unconsented closure” of a coal-fired power station constituted a *per se* taking of the facility owner’s property) (citing *Cedar Point Nursery v. Hassid*, 594 U.S. 139 (2021) and *Horne*, 576 U.S. 351).

By requiring Petitioners to involuntarily keep Craig Unit 1 available for operations according to the government’s instructions and mandating an

¹⁶ The *Pewee Coal* Court did not enjoin the government’s actions—the wartime emergency justified the government’s effort to keep coal mines operational. The fact of a justified emergency, however, did nothing to abate the Takings Clause requirement that the government compensate the plaintiff. *See Pewee Coal Co.*, 341 U.S. at 118 (holding that government is “entitled to the benefits and subject to the liabilities” of operating a facility it takes over).

unconsented re-opening of a non-operational facility—for not hours or days but months—DOE engages in a taking.

2. The Order Mandates Physical Changes to Petitioners' Property That Constitute a Physical Taking

The physical changes to Petitioners' property mandated by the Order also constitute a *per se* physical taking of Petitioners' property rights in Craig Unit 1 and other related property, such as fuel. *First*, mandating that Petitioners make Craig Unit 1 ready for operations compels Petitioners to make material physical changes to Craig Unit 1, including repairing out-of-service equipment that would otherwise remain unused. *Second*, operations require fuel, which compels Petitioners to deplete the Craig facility's limited fuel reserves intended for Craig Units 2 and/or 3 as operations at Unit 1 continue; these reserves were acquired and measured for the anticipated operation of two specific coal units and based on the assumption that Craig Unit 1 would retire at the end of 2025. Because the Order forces Petitioners to surrender and exhaust coal inventory for the government's chosen public purpose—coal that Petitioners acquired, allocated, and reserved for other units—it effects a *per se* physical taking of that property. And *third*, transmission capacity limitations for Petitioners' facilities at and near Craig Unit 1—the Craig units and Axial Basin—mean that requiring Craig Unit 1 to remain interconnected and possibly operating could constrain the ability of these resources to fully access the grid.

a. **Physical Changes to Craig Unit 1**

Bringing Craig Unit 1 back into service has already required modifications to the physical infrastructure on the site, beginning with repairs to Craig Unit 1's failed

Main Steam Stop Valves #1 and #2, and including additional maintenance to the unit's baghouse that had previously been deferred based on the unit's planned December 31, 2025 retirement. Petitioners must also perform emissions testing and other evaluations to ensure that Craig Unit 1 complies with applicable environmental requirements to the "maximum extent feasible while operating consistent with the emergency conditions." Order No. 202-25-14 at 4. Ongoing operations at the site will also require continual maintenance and staffing readiness, with the potential for further equipment failures that require repair and staffing (including overtime). And long before Craig Unit 1 was scheduled to retire, Petitioners both engaged in careful resource planning resulting in generation portfolios for the future that meet all member/customer needs, as well as planning reserve margins necessary to ensure reliable capacity in the event of extreme weather events and other emergencies, all based on the assumption that Craig Unit 1 would retire from service on December 31, 2025.

Compelling a property owner to make improvements to their property constitutes a physical taking when the mandated improvement benefits others—particularly the public at large—but do not benefit the property owner. "Put in general terms, government may not force a landowner to make an improvement that, while valuable to others, is useless to him" without it constituting a compensable taking. *Furey v. City of Sacramento*, 780 F.2d 1448, 1454 (9th Cir. 1986) (citing *Norwood v. Baker*, 172 U.S. 269 (1898) and *Myles Salt Co. v. Bd. of Comm'rs*, 239 U.S. 478 (1916)), *abrogated on other grounds*, *Cumbre Inc. v. State Compensation*

Ins. Fund, 403 F. App'x 272 (9th Cir. 2010). The Order requires Petitioners to make significant repairs to a facility they had planned to imminently retire for good. This is the kind of taking described in *Furey*.

b. The Craig Facility's Fuel Reserve

All three Craig Units were designed to run on coal obtained from the now-shuttered Colowyo Mine and the soon-to-be-shuttered Trapper Mine.¹⁷ Before closing the Colowyo Mine, Tri-State stockpiled sufficient reserves to operate its share of the Craig Units until their respective retirements. The only practical source of fuel for Craig Unit 1 to maintain readiness after its planned retirement, and to make use of in the event of a dispatch, are Craig Units 2 and/or 3's previously acquired and allocated reserves.¹⁸

This too constitutes a taking. *See Horne*, 576 U.S. at 357–65 (USDA requirement that a percentage of a grower's crop be set aside for public use constituted a *per se* physical taking). Just as the government in *Horne* effected a *per se* taking by requiring raisin growers to surrender a specific, identifiable portion of their crop for public use, by mandating that Petitioners consume coal inventory purchased and reserved for Craig Units 2 and/or 3, DOE appropriates that property for a public reliability objective. Under *Horne*'s reasoning, forced depletion of a

¹⁷ Tri-State believes that co-owners supply their share of Craig Units 1 and 2 through Trapper or other mines.

¹⁸ The diversion of this coal will necessitate future purchases of replacement fuel at uncertain cost, thereby imposing an additional, uncompensated expenditure that independently constitutes a taking. Use of an alternative source of supply not only results in additional costs, but also requires Tri-State to negotiate new contracts and alter operations at the Craig facility to account for variances between the physical qualities of different coal supplies.

utility's fuel reserves—no less than forced surrender of raisins—constitutes a physical taking of personal property requiring just compensation.

c. Axial Basin

The 145 MW Axial Basin generating facility is in the same general location as the Craig Generating Station and relies on much of the same transmission infrastructure. There is insufficient transmission capacity to move all electricity generated by the three Craig units and Axial Basin to the broader power grid. The Order thus constitutes appropriation of Tri-State's transmission infrastructure, a clear physical intrusion. This transmission limitation could lead to further physical intrusion by potentially forcing the curtailment of one or more of the other generation facilities to ensure that there was sufficient transmission capacity available for Unit 1 to comply with the Order.

B. DOE's Order Constitutes a Regulatory Taking

In addition to being a *per se* physical taking, the Order constitutes a regulatory taking. Regulatory takings occur where the government "imposes regulations that restrict an owner's ability to use his own property" but goes too far. *Cedar Point Nursery*, 594 U.S. at 148. The property rights implicated by the Takings Clause can include contract rights, *see Lynch v. United States*, 292 U.S. 571, 579 (1934), and government-created entitlements with economic value, *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986 (1984) (trade secrets constituted property for takings purposes). When evaluating whether a regulatory burden constitutes a taking, courts look to the test established in *Penn Central Transportation Co. v. New York City*, 438 U.S. 104, 124 (1982), which evaluates regulatory takings based on: (1) the regulation's economic

impact; (2) its interference with reasonable investment-backed expectations; and (3) the character of the government action.

The Order constitutes a regulatory taking under this analysis. The Order levies substantial economic impacts on Petitioners through both direct maintenance costs and the disruption to Petitioners' planning with associated downstream costs. The Order also disrupts Petitioners' reasonable investment-backed expectations rooted in years-long resource and economic planning, and interferes with Petitioners' operations and their contractual and regulatory rights.

1. Economic Impact

In requiring Petitioners to "take all measures necessary to ensure that Craig Unit 1 is available to operate," the Order places a heavy economic burden on Petitioners. As discussed above, Petitioners will necessarily incur a variety of operations and maintenance costs to ensure that Craig Unit 1 is ready and able to operate on request, with no economic benefit available from retaining the to-be-retired facility because it is uneconomic to operate.

Moreover, because of limited capacity over common transmission facilities, dispatching Craig Unit 1, while the other Craig Units are operating, can impede Tri-State's ability to dispatch its nearby Axial Basin generating facility. This in turn, prevents Petitioners from gaining the benefit of a margin on more economic resources, including renewable energy credits (which themselves have tangible value). *See Ruckelshaus*, 467 U.S. at 1011 (trade secrets are property); *Cienega Gardens v. United States*, 331 F.3d 1319, 1329 (Fed. Cir. 2003) (option rights to prepay subsidized mortgage and exit affordable-housing program are property); *Casitas*

Mun. Water Dist. v. United States, 543 F.3d 1276, 1288–96 (Fed. Cir. 2008) (water capacity rights are property). Forced operations would prevent Petitioners from most efficiently and affordably managing the transmission and generation system.

2. Investment-Backed Expectations

“The regulatory regime in place at the time the claimant acquires the property at issue helps to shape the reasonableness of [investment-backed] expectations.” *Palazzolo v. Rhode Island*, 533 U.S. 606, 633 (2001) (O’Connor, J., concurring). Where a change in regulation dramatically disrupts the economic basis for a property owner’s choices, it constitutes unreasonable interference with reasonable investment-backed expectations. *See Petworth Holdings, LLC v. Bowser*, 3d 347, 356–58 (D.C. Cir. 2018). An explicit government guarantee forms the basis of a reasonable investment-backed expectation. *See Ruckelshaus*, 467 U.S. at 1011.

The Order disrupts Petitioners’ reasonable investment-backed expectations on several fronts. DOE’s use of Section 202(c) authority to address long-term predicted shortages or grid reliability problems is a substantial and novel change to prior uses of Section 202(c) emergency authority.¹⁹ The Order fundamentally alters DOE’s longstanding approach in a novel, untested way that could not be predicted from DOE’s actions until recently, a decade after Craig Unit 1’s 2025 retirement was announced. Petitioners could not have fairly anticipated DOE’s novel approach to Section 202(c) when it engaged in business planning and made investment decisions; thus, the Order upsets Petitioners’ reasonable expectations.

¹⁹ *Rolsma* (2024) at 802–09, 839–46 (discussing paucity of involuntary Section 202(c) orders since WW2).

Moreover, diverting coal from Craig Unit 1 to comply with the Order depletes Craig Unit 2 and 3's fuel reserves and hinders Petitioners' right and ability to freely use those facilities consistent with their investment-backed expectations. The Order also upsets Petitioners' delicate contractual relationships. Even if Section 202(c) provides protection from enforcement action by Colorado under "environmental" laws,²⁰ disruption to these longstanding relationships disturbs Petitioners' ability to manage risk, engage in long-term planning, and maintain their reputations as reliable counterparties. Notwithstanding possible regulatory action, Petitioners have made commitments to stakeholders and planned their businesses around complying with existing environmental laws, which form part of their investment-backed expectations.

Finally, the electrical generation and transmission industry operates on a long time horizon. Craig Unit 1's closure was announced a decade ago, and numerous steps, such as deferring maintenance, reducing staffing, and redirecting capital expenditures, have been undertaken since. As is best practice, Petitioners engaged in extensive long-term planning with both government and private-sector partners, and Petitioners' plan to close Craig Unit 1 is part of a long-term plan to retire Unit 1 for economic reasons. Disruption of these long-term plans through a shorter-term Order upsets Petitioners' reasonable investment-backed expectations.

²⁰ Section 202(c)(3) does not define "environmental law" in this context and the scope of that term is untested.

3. Character of the Taking

The character of a governmental action is defined by “the purpose and importance of the public interest underlying [the] regulatory imposition, by obligating the court to inquire into the degree of harm created by the claimant’s prohibited activity, its social value and location, and the ease with which any harm stemming from it could be prevented.” *Maritrans, Inc. v. United States*, 342 F.3d 1344, 1356 (Fed. Cir. 2003) (internal quotation and citation omitted). “A ‘taking’ may more readily be found when the interference with property can be characterized as a physical invasion by government . . . than when interference arises from some public program adjusting the benefits and burdens of economic life to promote the common good.” *Penn Central*, 438 U.S. at 124 (citations omitted).

The character of the Order’s action further strengthens the case for a regulatory taking. As discussed in Section (I)(A), the Order effectively commandeers Craig Unit 1, its fuel, the potential dispatch of the nearby Axial Basin facility, and related infrastructure owned by Petitioners. The Order does not merely adjust the benefits and burdens of economic life, but rather directs operational control for a public reliability aim that could—and should—be solved through other means, and by other electrical utilities.

C. Just Compensation

The Takings Clause provides that “private property [shall not] be taken for public use, without just compensation.” U.S. Const. amend. V. Whether compensation is “just” is measured by relation “both to an owner whose property is taken and to the public that must pay the bill[.]” *United States v. Commodities Trading Corp.*, 339

U.S. 121, 123 (1950). “The owner’s loss is measured by the extent to which governmental action has deprived him of an interest in property.” *Wheeler v. City of Pleasant Grove*, 833 F.2d 267, 270 (11th Cir. 1987).

There is no established process by which Petitioners will obtain government compensation for losses relating to the Order. Section 202(c) and its implementing regulations, namely 10 C.F.R. 205.376, suggest recovery through FERC rate-making processes, but nowhere does the Order guarantee Petitioners’ complete recovery.²¹ As one example of the complexity of this undertaking, WAPA and the Bonneville Power Administration, as Federal Power Marketing Administrations located within WECC-NW, are exempt from most FERC jurisdiction.²² It is not immediately clear how the FERC rate-making process could be used to secure cost recovery from utilities serving areas located within the scope of the emergency but over which FERC lacks jurisdiction.

Moreover, even if Petitioners can and do recover some costs through this process, it is still not *just compensation* within the meaning of the Takings Clause. The duty to pay compensation for a taking runs to the government—“a takings claim requires just compensation from the government, not from a private third party.” *See*

²¹ Additionally, the terms of the Order could have substantive impact on Tri-State’s ability to make energy sales at market-based rates through authority granted to it by FERC. *See, e.g., Tri-State Generation and Transmission Ass’n*, 170 FERC ¶ 61,220, at PP 1, 22 and ordering para. (A) (2020) (generally providing Tri-State with authorization to transact at market-based rates). The circumstances are analogous for Platte River. Platte River also makes energy sales at market rates, but, as a government utility exempt under FPA Section 201(f), Platte River does not need market-based rate authority from FERC.

²² Stating that “[n]o provision in this subchapter shall apply to, or be deemed to include, the United States.” 16 U.S.C. § 824(f) (2024).

Deutsche Bank Nat'l Trust Co. v. SFR Invests. Pool 1, LLC, Case No. 2:14-cv-001131-APG-VCF, 2016 WL 1248704, at *5 (D. Nev. Mar. 28, 2016); *see also Baker v. City of McKinney*, 608 F. Supp. 3d 457, 465–67 (E.D. Tex. 2022) (plaintiff was entitled to full compensation for a taking by police even though she obtained additional money from donations). This is particularly true where, as here, at least some of Petitioners' relief will come from Tri-State's members and Platte River's ratepayers, even if FERC orders some level of cost recovery. DOE cannot simply transfer the constitutional obligation to provide just compensation onto private parties—including, here, rural communities and the residents of four small Colorado municipalities—through regulatory mandates without satisfying its own Takings Clause obligations.

II. THE ORDER DISRUPTS PETITIONERS' RELIABILITY PLAN AND FAILS TO ACCOUNT FOR VIABLE ALTERNATIVES

Separate from whether DOE must compensate Petitioners for the impact of the Order on their property and operations, the Order suffers from statutory and constitutional frailties. While Petitioners share DOE's goal of ensuring that the Northwestern United States has reliable and affordable electricity, the Order misses the mark.

First, the Order violates Petitioners' constitutional due process rights to pre-deprivation notice and a hearing. While emergencies sometimes allow the government to provide only post-deprivation process, the government must do more than reference the word “emergency”—rather, it must show that the *kind* of emergency that requires such fast-moving action has occurred. The Order's asserted

emergency is no such emergency. And the Order disrupts a considered resource planning effort.

Second, the Order does not meet the requirements of Section 202(c). It does not consider reasonable alternatives as required by Section 202(c), including Petitioners' carefully calibrated reliability planning, using both thermal and renewable resources based on findings including from objective, industry-leading forecasting methods. *Third*, the Order is inconsistent with the FPA's objectives. The Order is, therefore, contrary to law and arbitrary and capricious.²³

A more deliberative process would, on the whole, work better to address DOE's concerns about the reliability of the electrical grid in the northwestern United States, and, in particular, the Mountain West. Petitioners stand ready to work with DOE to make their service area as reliable as possible and best serve their members and customers, doing so in a manner that is economically efficient.

A. The Order Violates Petitioners' Constitutional Due Process Rights and Disrupts Carefully Considered Reliability Planning

The Fifth Amendment's Due Process Clause guarantees that no person shall be "deprived of life, liberty or property" by the federal government "without due

²³ As DOE is aware, Petitioners have already taken and will continue to take steps to comply with the Order. This includes incurring compensable costs and expenses. Although Petitioners take the position that the Order does not comply with the requirements of Section 202(c), Petitioners are nonetheless entitled to cost recovery under Section 202(c) and as a compensable taking even if the Order is determined to be unlawful. Petitioners note that Section 202(c) is an emergency provision, and, for that reason, recovery pursuant to its terms should not turn on an ultimate determination of the lawfulness of the Order. Further, the Order provided notice to all potential ratepayers that rights to recovery would accrue to Petitioners (and the other co-owners) beginning on December 30, 2025. To bar Petitioners from recovering these already-incurred costs would be inconsistent with Section 202(c)'s purpose to respond to emergency conditions. Petitioners' position is based on currently available facts and information. Petitioners reserve all rights.

process of law.” U.S. Const. amend. V. At its core, due process requires notice and an opportunity to be heard before the government takes action affecting protected interests. *Memphis Light, Gas & Water Division v. Craft*, 436 U.S. 1, 19 (1978). This principle applies across regulatory regimes where hearings are generally required before agencies impose obligations or alter rights. Under the FPA, most Commission (*i.e.*, FERC or DOE) actions—such as rate changes or interconnection orders—cannot take effect without a prior hearing. *See generally* 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o, & 824p.

Section 202(c) orders are unusual in that they may be issued without any prior hearing, reflecting their purpose as an emergency tool meant to address fast-moving and unexpected situations. *Indus. Park Dev. Co. v. EPA*, 604 F. Supp. 1136, 1142 (E.D. Pa. 1985) (“[A]dministrative deprivation of [a] property interest violates the Constitution’s due process guarantees except in very narrowly circumscribed emergency situations.”). However, “[t]here is a relation between the kind of emergency and nature of the solution.” *Pa. Gas & Water Co.*, 427 F.2d at 577. Where, as here, the declared emergency does not involve immediate and concrete concerns (potentially in 2029 if new generation is not built as planned), a hearing is certainly feasible, and, absent a hearing, Petitioners are deprived of their right to due process. *See Indus. Park Dev. Co.*, 604 F. Supp. at 1145 (holding that “[u]nilateral administrative action . . . should be saved for cases of extreme emergency”); *Miller*,

945 F.2d at 353 (emergency insufficient to avoid need for pre-deprivation hearing, but concluding that sufficient hearing had occurred).

The Order’s emergency does not rest on an urgent and immediate need for additional generation to address a specific incident or event, such as unusually extreme weather or another plant’s sudden unplanned outage. Rather, the emergency articulated by the Order is based on broader concerns about the sufficiency of generation capacity and reliability in the WECC Northwest assessment area over time and in the future. Because the Order does not demonstrate an immediate crisis, it cannot justify dispensing with the pre-deprivation hearing requirement. Formal notice to the co-owners, moreover, was lacking. The Order’s imprecision on boundaries of the region at issue,²⁴ not only highlights the lack of immediate crisis, but also fails to give Petitioners proper notice of the precise contours of the emergency. Petitioners were, therefore, deprived of their constitutional right to notice and a hearing before the Order came into effect.

The effect of this deprivation is significant. Petitioners have carefully planned the retirement of the Craig facility—including Craig Units 2 and 3’s reliance on

²⁴ The Order relies on NERC’s 2024 LTRA, which discusses conditions throughout the sweeping and populous WECC Northwest assessment area—an area that includes “Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota[.]” See N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, at 127 (corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf. However, NERC’s more recent and more targeted 2025–2026 Winter Reliability Assessment from November 2025 shows that the new WECC-Rocky Mountain region—redrawn to better reflect local conditions than the vast and heterogeneous old WECC-Northwest region—has more than enough power to meet immediate winter needs. See N. Am. Elec. Reliability Corp., 2025 Winter Reliability Assessment (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf. Craig Unit 1 and most of Petitioners’ service territory is located in the WECC-Rocky Mountain region.

stockpiled coal. Petitioners have also planned and invested to bring new generation online, such as the Axial Basin facility, to ensure reliability even as Craig Unit 1 is carefully retired. If the Order proceeds and Unit 1 runs, it deprives the other units of fuel. This undermines Petitioners' planning, imposes "reliability" costs on Tri-State's members and Platte River's ratepayers a second time, and disrupts the operation and economics of the other coal resources still operating. A more deliberative process with the required pre-deprivation hearing would have allowed Petitioners to work with DOE to address concerns about reliability and shape a more workable plan.

B. The Order Failed to Consider Reasonable Alternatives

DOE could have taken other steps to more effectively meet the energy emergency identified in the Order. Section 202(c) requires the Secretary to exercise "judgment" and select only those measures that "will *best* meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1) (emphasis added). Implicit in this mandate is the recognition that alternatives be considered and ruled out. DOE should have conducted and disclosed an analysis showing why the path selected is the "best" course forward, particularly in light of the potential 2029 time-horizon of the asserted emergency. This is consistent with the emergency nature of the powers contained in Section 202(c), which should not be exercised where "alternatives offered a more confined solution" to the emergency at issue. *Pa. Gas & Water Co.* 427 F.2d at 577 (considering analogous powers under the Natural Gas Act); *see also Farmers Union Cent. Exchange, Inc. v. FERC*, 734 F.2d 1486, 1511 (D.C. Cir. 1984) ("It is well established that an agency has a duty to consider reasonable alternatives to its chosen policy, and to give a reasoned explanation for its rejection of such

alternatives.”) (citation and footnote omitted). The Order reflects no consideration of alternatives, let alone a case for mandating Craig Unit 1 remain active over other options, and is thus contrary to law and arbitrary and capricious.

Compelling Craig Unit 1 to remain available to operate after its planned retirement date must be the “best” measure to address this long-term reliability concern across the region described in the Order. “[R]easonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions.” *Michigan v. EPA*, 576 U.S. 743, 753 (2015). This weighing process requires engagement with the factual record, as reflected in DOE regulations, which require applicants to provide extensive information related to operations and alternative courses of action.²⁵ These requirements reflect the understanding that Section 202(c) should only be used where unit-specific alternatives have been considered, applied, and deemed inadequate based on the facts on the ground. The record in this proceeding reflects that neither these facts nor any reasonable alternatives were considered in connection with the Order.

DOE’s need to consider alternatives, based on a clear factual record, is particularly important given Craig Unit 1’s status. Craig Unit 1 is an older, uneconomic unit. Due to its long-planned retirement, Craig Unit 1 has experienced years of prudently deferred maintenance, and therefore faces particularly high costs to restore and maintain operations compared to possible alternatives.

²⁵ See 10 C.F.R. § 205.373. The specified information includes “conservation or load reduction actions,” “efforts . . . to obtain additional power through voluntary means,” and “[a] listing of proposed sources and amounts of power necessary from each source to alleviate the emergency and a listing of any other ‘entities’ that may be directly affected by the requested order.” 10 C.F.R. § 205.373(g)–(i).

Further, the Order fails to consider how mandating Craig Unit 1’s continued operation interferes with Petitioners’ ability to invest in other generation capacity and therefore undermines the very ends that it purports to advance. For instance, the Axial Basin generating facility relies on the same transmission infrastructure as the Craig units. That infrastructure is already congested; if all three Craig units are operating, Craig Unit 1’s continued operation could interfere with the ability of new alternatives like Axial Basin to provide economic power to the grid.

A lawful exercise of the emergency powers contained in Section 202(c) required consideration of reasonable regulatory alternatives. For example, the Order does not explain why DOE or FERC could not proceed through the rulemaking process pursuant to section 403 of the Department of Energy Organization Act, 42 U.S.C. § 7173, to devise a plan to ensure reliability through a more fulsome, consultative process. Proceeding with a notice of proposed rulemaking for consideration and final action would have minimal short-term risks and is appropriate to the timeline of the described emergency, which, by DOE’s supporting evidence, is predicted to occur no earlier than “in Summer 2029 onward” (because “the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed”).²⁶ Similarly, DOE could have evaluated whether it had authority to take proactive action to insure that “new resources” in the region are not “significantly delayed.”

²⁶ N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, at 128 (corrected July, 11 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

In the absence of such consideration, and the disclosure of the relevant rationale, Petitioners and the public “cannot weigh the merits of an agency decision nor compare it to other alternative actions[.]” *Rocky Mountain Wild v. Bernhardt*, 506 F. Supp. 3d 1169, 1187 (D. Utah 2020). The Order does not discuss why Craig Unit 1’s continued operation was selected as the “best” solution to the described conditions, or if alternatives were considered, what those alternatives were, and why any considered alternatives were discarded. Thus, it was contrary to law and an arbitrary and capricious exercise of agency authority.

C. The Order is Inconsistent with the FPA’s Statutory Objectives

Courts reject agency action as arbitrary and capricious if it is “inconsistent with the statutory mandate” or “frustrate[s] the policy that Congress sought to implement.” *FEC v. Democratic Senatorial Campaign Comm.*, 454 U.S. 27, 32 (1981). The FPA was passed to advance a variety of policy goals, including protecting consumers from “excessive rates and charges,” *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947, 952 (D.C. Cir. 2016) (citation omitted); “maintaining competition to the maximum extent possible[.]” *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973); and encouraging the “orderly development of plentiful supplies of electricity . . . at reasonable prices.” *NAACP v. FPC*, 425 U.S. 662, 670 (1976).²⁷

²⁷ “Recognizing the careful balance that the FPA strikes between federal and state regulation” FERC recently found that “states retain exclusive authority over . . . the generation mix.” *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61217, at P165 (Dec. 18, 2025). Long-term economic and planning decisions regarding Tri-State’s resource mix had been approved by the State of Colorado through the 2020 and 2023 Energy Resource Plans. This jurisdictional division of responsibility and federal respect for state policymaking is also a policy of the FPA. See *Sierra Club v. FERC*, 145 F.4th 74, 81 (D.C. Cir. 2024) (respecting the role of state regulators); *NextEra Energy Resources, LLC v. FERC*, 118 F.4th 361, 365 (D.C. Cir. 2024) (“[FERC] may regulate the transmission, but not the generation, of electricity[.]”).

The Order, by compelling an uneconomic unit to remain operational on the eve of its retirement, upends Petitioners' ability to plan their systems in an orderly fashion and to act with confidence in a competitive marketplace. Because the Order is at odds with the statutory objectives of the FPA, it is arbitrary and capricious.

CONCLUSION

Tri-State is a not-for-profit, member-owned cooperative and Platte River is a not-for-profit municipally owned joint action agency. Both utilities aim to work with government at all levels to best serve the communities to which they provide reliable and affordable energy. In that light, Tri-State has taken the steps necessary to plan for a reliable system that would have a planning reserve margin of at least 22% even with the retirement of Craig Unit 1, for which its Utility Members have paid. Platte River has likewise proactively developed resources that more than replace Craig Unit 1's energy and capacity to reliably serve its owner communities and meet the planning reserve margins SPP requires for its expanded western footprint (19% for summer; 40% for winter), and for which its owner communities have already paid.

The Order effects an uncompensated taking of Petitioners' property, denies them due process, and fails to meet Section 202(c)'s statutory requirement that DOE's chosen policy rationally "best address[es]" the stated emergency. Requiring Petitioners—not all of whom are located in the WECC Northwest region described by the Order—to suffer additional costs *and* uncertainty because of potential conditions created by utilities outside Petitioners' service area, is fundamentally unfair and harms affordability. Petitioners urge DOE to reconsider the Order.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties below. Dated at Washington, D.C., this 29th day of January 2026.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-21
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit V: Department, Order No. 202-25-8 (Aug. 28, 2025)



Department of Energy

Washington, DC 20585

Order No. 202-25-8

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order No. 202-25-4

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, PA. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. That order was based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units is necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.¹ He stated that, through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.² Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

¹ *Keeping the Lights On: Examining the State of Regional Reliability*, Before the H. Comm. on Energy and Com., S. Comm. on Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM Interconnection) (Asthana Test.) at 4-5, available at

<https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf>.

² *Id.*

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that “available generation capacity may fall short of required reserves in an extreme planning scenario.”³ In its February 2023 assessment “*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report),” PJM highlighted increasing reliability risks in the coming years due to the “potential timing mismatch between resource retirements, load growth and the pace of new generation entry” under “low new entry” scenarios for renewable generation.⁴

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found “the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry.”⁵

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM this summer. This need is evidenced by the fact that the Eddystone Units were called on by PJM to generate electricity during heat waves that hit the region in June and July.

According to U.S. Environmental Protection Agency data, the Eddystone Units generated over 17,000 MWhs during the month of June.⁶ Further, over a period of hot weather from June 23 to June 26, Unit 3 ran for a total of 65 hours and Unit 4 ran for a total of 59 hours.⁷ During a hot weather period from July 28 to July 30, Unit 3 ran for 39 hours and Unit 4 ran 8 hours.⁸

Over the course of the summer, PJM has issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) covering a total of 20 days, including days in June, July, and August.⁹ The hot weather may continue in the near term, as the Seasonal Outlook released by the National Oceanic and Atmospheric Administration (NOAA) on August 21, 2025, projects between a 40%

³ *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk*, PJM Interconnection, L.L.C. (May 9, 2025), <https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/>.

⁴ *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM (Four Rs Report) at 1, (Feb. 24, 2023), <https://www.pjm.com/-/media/DotCom/library/reports-notice/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx>.

⁵ *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025).

⁶ See *Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), <https://campd.epa.gov/data/custom-data-download> (search criteria Emissions >> Monthly >> Unit (default) >> Apply >> “2025” and “June” (search date Aug. 22, 2025)).

⁷ See *PJM daily reports to DOE under Order No. 202-25-4, June 24-27, 2025*.

⁸ See *PJM daily reports to DOE under Order No. 202-25-4, July 29-31, 2025*.

⁹ See PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, <https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf> (search range set to: effective from 06/01/2025 until 08/31/2025).

and 60% probability of above-normal temperatures in the Mid-Atlantic region, which includes the PJM region, over the next three calendar months.¹⁰

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In its news release expressing support for Order No. 202-25-4, PJM explained that it has “repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers.”¹¹

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.¹² PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.¹³ PJM determined that the pace of new capacity additions “would be insufficient to keep up with expected retirements and demand growth by 2030.”¹⁴ PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that “[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report”¹⁵ PJM warned that its “resource adequacy concerns are increasing at an extraordinary pace.”¹⁶ PJM went on to explain, its “resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers” and that its preliminary analysis shows “substantial increases [in load additions] since the 2024 forecast” for both the summer and winter seasons.¹⁷ According to PJM, “load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence.”¹⁸ Although the RRI process will help expedite the construction of needed

¹⁰ *Seasonal Outlook*, NOAA Climate Prediction Ctr., (Aug. 21, 2025),

https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

¹¹ *PJM Statement on the U.S. Department of Energy 202(c) Order of May 30*, PJM (May 31, 2025),

<https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250531-doe-202c-statement-to-defer-retirements-of-certain-generators.pdf>.

¹² Four Rs Report, *supra* n. 4, at 2.

¹³ *Id.*

¹⁴ *Id.* at 16, Table 1.

¹⁵ *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).

¹⁶ *Id.*

¹⁷ *Id.* at 10-11. See also *id.* at 13 (“the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements...”).

¹⁸ *Id.* at 14.

new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.¹⁹

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM’s Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as “extraordinary” and “unprecedented,” stating that it “could not have been foreseen as recently as a year ago.”²⁰ Mr. Bielak expressed the opinion that the “rapid” retirement of thermal generation resources, “extreme” forecasted load growth, and “delays in new generation resources achieving commercial operation,” would adversely affect resource adequacy throughout PJM’s electricity grid.²¹

The North American Electric Reliability Corporation (NERC) has raised similar concerns. According to NERC’s 2024 Long Term Reliability Assessment, “PJM could face future resource adequacy challenges, impacting system reliability and PJM’s ability to serve load.”²² NERC assessed the PJM region at an elevated risk starting in 2026,²³ explaining that “[r]esource additions are not keeping up with generator retirements and demand growth.”²⁴ NERC stated that the loss-of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.²⁵

Order 202-25-4 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid,” President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”²⁶ President Trump likewise recognized, in Executive Order 14156, “Declaring a National Energy Emergency,” that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”²⁷ The Executive Order adds: “Hostile state and non-state foreign actors have targeted our domestic energy infrastructure,

¹⁹ See *id.*, Attachment C (Affidavit of Mr. Donald Bielak) ¶ 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, “could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.”).

²⁰ *Id.* at 12.

²¹ *Id.* at 7.

²² 2024 *Long-Term Reliability Assessment*, North American Electric Reliability Corporation at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf at 92.

²³ *Id.* at 4.

²⁴ *Id.* at 7.

²⁵ *Id.* at 91-92.

²⁶ Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

²⁷ Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”²⁸

The Department of Energy’s (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President’s directive in Executive Order 14262, details the myriad challenges affecting the Nation’s energy outlook. It concludes, “Absent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”²⁹ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.³⁰ As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.³¹ Regarding the PJM region, the Department’s analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.³² Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load hours of approximately 21.335 GW.³³

Grid operators, including PJM, have likewise acknowledged the Nation’s current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a “growing resource adequacy concern . . . impacting a significant part of our country.”³⁴ Mr. Asthana explained that the “rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth.”³⁵ Mr. Asthana noted that, “though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.” Therefore, Mr. Asthana stated that PJM

²⁸ *Id.*

²⁹ See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy (July 2025), at 1, <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

³⁰ See PPL Corporation Q2 2025 Investor Update, PPLC Corporation (July 31, 2025) at 7, https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf

³¹ See Dominion Energy Virginia, Q4 2024 Earnings Call (Feb. 12, 2025), at 18, https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slides-vTCII.pdf.

³² *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 28, <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

³³ *Id.* at 27.

³⁴ Asthana Test. at 4.

³⁵ *Id.*

“encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability.”³⁶

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”³⁷ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-4 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until November 26, 2025.³⁸

Based on my determination of an emergency set forth above, I hereby order:

- A. From 5:03PM EDT on August 28, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units has operated in

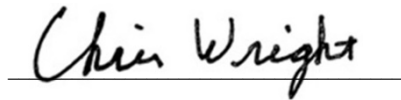
³⁶ *Id.* at 10.

³⁷ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).

³⁸ 16 U.S.C. § 824a(c)(4).

compliance with the allowances contained in this Order.

- C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By September 12, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.
- H. This Order shall be effective from 5:03 PM Eastern Daylight Time (EDT) on August 28, 2025, and shall expire at 00:00 EST on November 26, 2025, with the exception of applicable compliance obligations in paragraph D.
- I. Issued in Washington, D.C., at 7:11 PM Eastern Daylight Time on this 27th day of August 2025.

A handwritten signature in black ink, reading "Chris Wright", is written over a horizontal line.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

Chairman David Rosner

Commissioner Lindsay S. See

Commissioner Judy W. Chang

Pennsylvania Public Utility Commissioners

Chairman Stephen M. DeFrank

Vice Chair Kimberly M. Barrow

Commissioner Kathryn L. Zerfuss

Commissioner John F. Coleman, Jr.

Commissioner Ralph V. Yanora

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-21
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit VV: CoPUC, Tri-State, Notice of 2026 Resource Adequacy Annual Report,
filed on March 17, 2026, in Proceeding No. 26M-0028E

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

**2026 ELECTRIC RESOURCE
ADEQUACY ANNUAL REPORTS**

)
)
)
)
)

PROCEEDING NO. 26M-0028E

**TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.'S
NOTICE OF 2026 RESOURCE ADEQUACY ANNUAL REPORT**

Tri-State Generation and Transmission Association, Inc. ("Tri-State"), pursuant to §40-43-104(1)(a), C.R.S., respectfully submits this Notice of 2026 Resource Adequacy ("RA") Annual Report informational filing.

I. BACKGROUND

On or before April 1, 2026, Tri-State, as a load serving entity ("LSE"), is required under §40-43-104(1)(a), C.R.S., to provide the Colorado Public Utilities Commission ("Commission") a RA Annual Report identifying the generating resources and accredited capacity used to serve its Utility Members.¹ On January 1, 2026, the Commission opened Proceeding No. 26M-0028E to receive these reports.

II. TRI-STATE'S 2026 RA REPORT

Tri-State has complied with this requirement with Figure 1 and Table 1.² Tri-State's 2025 RA Annual Report has also been made available on Tri-State's website, here: <https://tristate.coop/resource-planning>.³

¹ The Colorado Resource Adequacy Act of 2023 became effective August 7, 2023 (House Bill 23-1039).

² Colorado Energy Office ("CEO") has requested that entities subject to §40-43-104, C.R.S. also complete a "Resource Adequacy Spreadsheet" to be returned to CEO by April 30, 2026. Tri-State intends to voluntarily respond to this request.

³ On January 11, 2025, Tri-State received guidance from CEO (pursuant to §40-43-104(3), C.R.S.) requiring each LSE to make its RA annual report available on its website and searchable by including "Resource_Adequacy_2026."

FIGURE 1 –LOAD AND RESOURCES

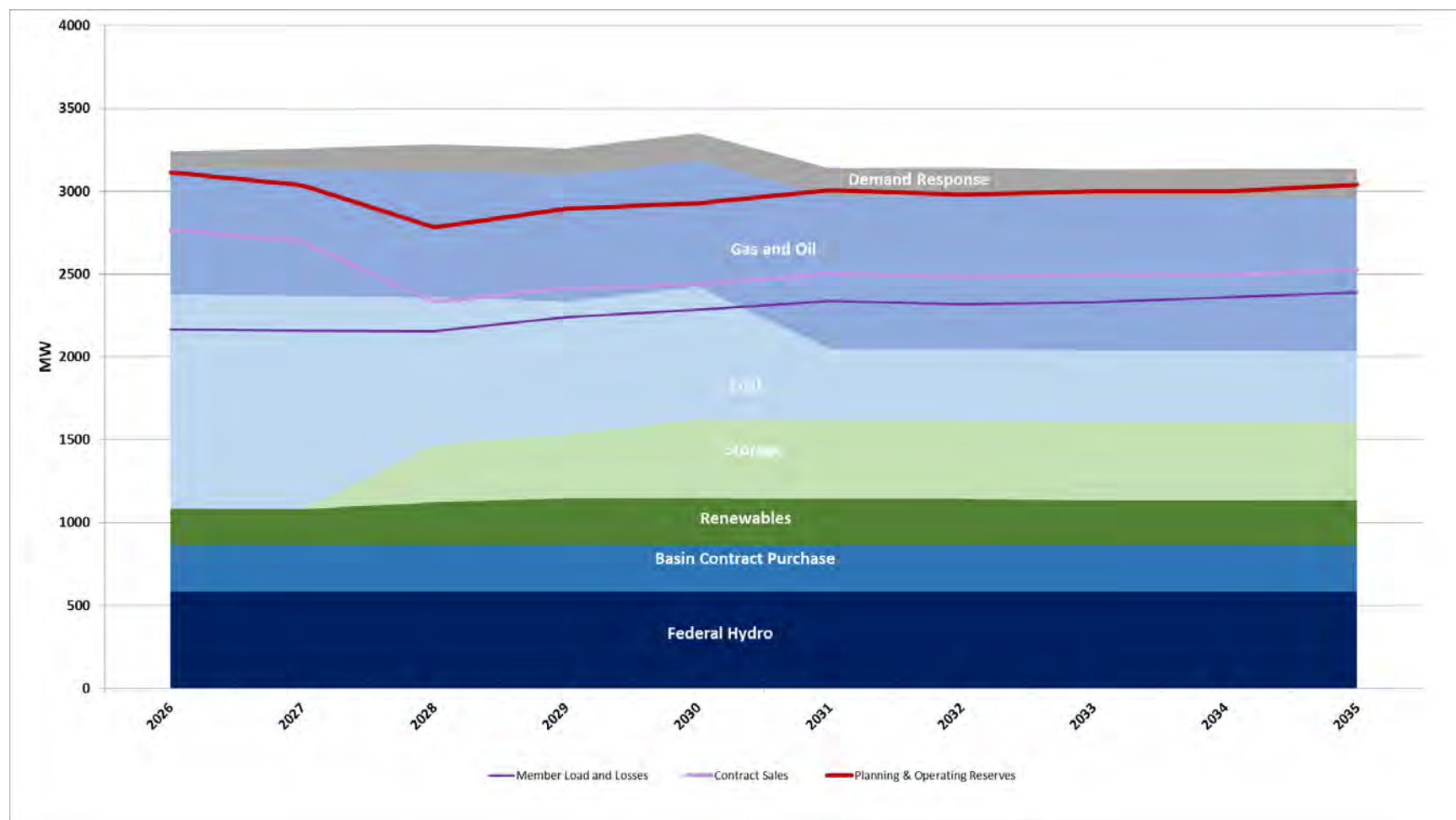


TABLE 1 – LOAD AND RESOURCES

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Federal Hydro	584	584	584	584	584	584	584	584	584	584
Contract Purchases	278	278	278	278	278	278	278	278	278	278
Renewables ⁴	226	222	260	286	286	281	281	272	273	271
Demand Response	100	124	161	162	164	165	167	169	170	172
Coal Generation ⁵	1287	1286	888	800	800	431	432	431	432	431
Gas & Oil Generation ⁶	765	765	765	765	765	925	925	925	925	925
Storage ⁷	0	0	349	383	474	474	474	474	474	474
<i>Total Resources</i>	3239	3257	3285	3259	3351	3138	3141	3132	3136	3135
Member Load and Losses ⁸	2166	2160	2156	2241	2284	2337	2317	2332	2358	2390
Planning & Operating Reserves	348	341	451	476	489	505	498	502	502	511
Contract Sales	601	537	177	177	155	166	166	166	139	139
<i>Total Obligations</i>	2001	1971	1781	1865	1906	1957	1936	1949	1948	1978
Excess Resources	123	219	501	364	422	131	160	133	136	95

⁴ Capacity is based on applying the effective load carrying capability by renewable technology to the nameplate of renewable resources.

⁵ Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.

⁶ Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.

⁷ Capacity is based on applying the effective load carrying capability for storage to the nameplate of storage resources.

⁸ Western Interconnection Load.

Tri-State's report covers its Utility Members as LSEs, for the portion of their loads served by Tri-State,⁹ pursuant to §40-43-104(2), C.R.S.

In accordance with §40-43-104(1)(c), C.R.S., Tri-State understands that the Colorado Energy Office will, by July 1, 2026, utilize Tri-State's report and that of other LSEs to create an aggregated statewide report.

Submitted this 17th day of March, 2026.

WOMBLE BOND DICKINSON (US) LLP

/s/ Dietrich C. Hoefner

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Phone: (303) 254-3534

Email: liz.stevens@tristategt.org

**Attorneys for Tri-State Generation and
Transmission Association, Inc**

⁹ Tri-State expects that certain Utility Members that are exiting Tri-State membership may supply separate RA Annual Reports, to the extent applicable.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-21
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit W: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin,
Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

PROCEEDING NO. 23A-____E

IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND
TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC
RESOURCE PLAN

DIRECT TESTIMONY AND ATTACHMENTS OF
LISA K. TIFFIN
ON BEHALF OF
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

NOTICE OF CONFIDENTIALITY

A portion of this document has been filed under seal.

This document contains Highly Confidential Attachments.

• <u>LKT-7</u> ~~LKT-1 Attachment B~~ - o Pages: 5-9, 16, 17 • <u>LKT-10</u> ~~LKT-1 Attachment B-3~~ - o Pages: 1, 2 • <u>LKT-15</u> ~~LKT-1 Attachment C-1~~ - o Pages: 3, 4 • <u>LKT-16</u> ~~LKT-1 Attachment C-2~~ - o Pages: 9, 10, 11 12, 15, 16, 19 • <u>LKT-17</u> ~~LKT-1 Attachment C-3~~ - o Pages: 5, 6, 7	• <u>LKT-19</u> ~~LKT-1 Attachment D-1~~ - o Pages: 6-10, 16, • <u>LKT-20</u> ~~LKT-1 Attachment D-2~~ - o Pages: 9-13, 21-22 • <u>LKT-21</u> ~~LKT-1 Attachment D-3~~ - o Pages: 10, 11, 13, 16, 18, 19, 26, 27 • <u>LKT-22</u> ~~LKT-1 Attachment D-4a~~ - o Pages: 8, 10, 12, 14, 16, 17, 18, 25, 26 • <u>LKT-23</u> ~~LKT-1 Attachment D-4b~~ - o Pages: 10, 13, 16, 19, 20, 21, 28, 29	• <u>LKT-24</u> ~~LKT-1 Attachment D-5~~ - o Pages: 10, 12, 14, 16, 18, 20, 22, 23, 24, 32, 33 • <u>LKT-26</u> ~~LKT-1 Attachment F~~ - o Pages: 15 • <u>LKT-27</u> ~~LKT-1 Attachment F-1~~ - o Pages: 5-1,686 • <u>LKT-30</u> ~~LKT-1 Attachment G-2~~ - o Pages: all • <u>LKT-32</u> ~~LKT-1 Attachment G-4~~ - o Pages: all

This document contains Confidential Attachments.

• <u>LKT-7</u> ~~LKT-1 Attachment B~~ - o Pages: 4, 5, 7, 13 • <u>LKT-16</u> ~~LKT-1 Attachment C-2~~ - o Pages: 7 • <u>LKT-17</u> ~~LKT-1 Attachment C-3~~ - o Pages: 5, 6, 7	• <u>LKT-26</u> ~~LKT-1 Attachment F~~ - o Pages: 8, 9 • <u>LKT-29</u> ~~LKT-1 Attachment G-1~~ - o Pages: 44

December 1, 2023

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Attachment LKT-30HC	Benchmarking Analysis (B&V)
Attachment LKT-31	Addendum to 2020 DSM Potential Study and BE Potential Study (Mesa Point Energy)
Attachment LKT-32	Reliability Evaluation
Attachment LKT-32HC	Reliability Evaluation

¹ ~~LKT-1 includes several attachments,~~ each of which are listed on page 5 the report.

**I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY AND
RECOMMENDATIONS**

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Lisa K. Tiffin. My business address is 1100 West 116th Avenue,
Westminster, CO 80234.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am employed by Tri-State Generation and Transmission Association, Inc. ("Tri-
State") as Vice President, Planning & Analytics.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A: I am testifying on behalf of Tri-State.

**Q: HAVE YOU PREPARED A STATEMENT OF YOUR EXPERIENCE AND
QUALIFICATIONS?**

A: Yes. My Statement of Qualifications is attached to my testimony as **Attachment
LKT-4.**

**Q: PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE IN THE
ELECTRICITY UTILITY INDUSTRY.**

A: I have 30 years of experience in the electric utility industry. Prior to my current
position, I managed Tri-State's short-term marketing and operations, applications
support services, and resource planning. Prior to joining Tri-State, I worked in
consulting, bulk electric system marketing and operations, and energy
transportation and sales for the Structure Group, Illinois Municipal Electric Agency,
Freeman Energy, and ABB Power T&D. I have a Bachelor of Science degree in
Political Science from MacMurray College in Illinois and hold a North American

1 Electric Reliability Corporation (“NERC”) Balancing Interchange and Transmission
2 Operator certification.

3 I have worked for Tri-State for 16 years, non-consecutively, and have
4 served in a variety of management leadership roles within the organization focused
5 on energy planning, management, and delivery. These roles included overseeing
6 teams of staff supporting day-ahead trading and scheduling, budgeting and
7 forecasting, resource planning, and analytics. In my current role, I oversee Tri-
8 State’s long-term generation resource plan, load forecasting, merchant
9 transmission function, and related state regulatory affairs.

10 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

11 A: My testimony provides a summary of Tri-State’s 2023 Electric Resource Plan
12 (“ERP”), as well as the underlying and influential factors reflected in the ERP, such
13 as Member needs, regulatory and environmental compliance, market and policy
14 dynamics, and financial and reliability considerations.

15 **Q: PLEASE IDENTIFY THE OTHER WITNESSES WHO WILL BE TESTIFYING ON**
16 **BEHALF OF TRI-STATE.**

17 A: Tri-State’s witnesses that have also filed Direct Testimony in this proceeding are
18 as follows:

- 19 • Ms. Susan Hunter, Vice President, Energy Resources. Ms. Hunter’s
20 testimony addresses Tri-State’s proposed approach to Phase II of the 2023
21 ERP for competitive bidding and procurement procedures. She also
22 addresses the Resource Acquisition Period (“RAP”) Action Plan.

- 1 • Mr. Brian Thompson, Resource Planning Manager. Mr. Thompson's
2 testimony addresses the technical aspects of Tri-State's Phase I filing,
3 including the analytical methodologies employed, the significant technical
4 and operational assumptions used in scenario and sensitivity modeling, as
5 well as studies commissioned for or prepared by Tri-State to support
6 analytical inputs to the modeling.
- 7 • Ms. Lisa Lynn, Manager Analytics and Forecasting. Ms. Lynn describes Tri-
8 State's process for developing the load forecasts used in the scenario and
9 sensitivity modeling.
- 10 • Mr. Barry Ingold, Chief Operating Officer. Mr. Ingold describes Tri-State's
11 owned thermal resources and processes for procurement and construction
12 of a new gas facility.
- 13 • Mr. Andy Berger, Vice President, Environmental Compliance and Policy.
14 Mr. Berger provides an overview of the environmental laws and policies
15 influencing Tri-State's resource planning and will explain how compliance
16 with state and federal environmental laws affects Tri-State's ERP.
- 17 • Mr. Ryan Hubbard, Senior Manager, Transmission Business Strategy. Mr.
18 Hubbard discusses transmission system capabilities, including injection
19 capabilities, of Tri-State's transmission system, Tri-State's transmission
20 planning process, and relevant transmission needs and planned projects.
21 He also provides information as required by Rule 3605(d) or identifies where
22 such information can be found in the ERP.

- Mr. Chad Orvis, Senior Manager, People and Culture. Mr. Orvis describes Tri-State's workforce transition planning efforts and community engagement related to anticipated plant closures.

Q: WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A: I recommend that the Colorado Public Utilities Commission ("Commission") approve Tri-State's Phase I 2023 ERP, including the Inflation Reduction Act Scenario ("IRA Scenario") as Tri-State's preferred plan and the following items Tri-State has proposed for Phase II of the 2023 ERP:

- Phase II timeline;
- Phase II RFPs;
- Bid evaluation criteria and bid policy;
- Independent Evaluator ("IE") Statement of Work;
- Model power purchase agreements ("PPAs") and Term Sheets;
- Phase II Implementation Report components;
- 45-Day Report content; and
- RAP Action Plan.

II. TRI-STATE OVERVIEW

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: The purpose of this section of my Direct Testimony is to provide an overview of Tri-State and its system.

Q: WHO IS TRI-STATE?

A: Tri-State is a not-for-profit cooperative wholesale power supplier whose mission is

1 to provide its Member systems a reliable, affordable, and responsible supply of
2 electricity in accordance with cooperative principles. Tri-State is a cooperative of
3 45 members, including 42 electric distribution cooperatives and public power
4 districts in four states (Colorado, New Mexico, Wyoming and Nebraska) that
5 provide power to more than one million customers across nearly 200,000 square
6 miles of the western United States.

7 **Q: PLEASE PROVIDE AN OVERVIEW OF THE TRI-STATE SYSTEM.**

8 A: Tri-State's load and/or its resources are located in six Balancing Authorities ("BAs")
9 – Southwest Power Pool ("SPP"), PacifiCorp ("PAC"), Public Service Company of
10 New Mexico ("PNM"), Public Service Company of Colorado ("PSCo"), Tucson
11 Electric Power ("TEP") and Western Area Colorado Missouri ("WACM"). Tri-State
12 had 2454 MW of owned generation capacity, 786 MW of renewable PPA capacity,
13 580MW of federal hydropower capacity and 616 MW of firm contracted capacity in
14 2022 serving 3071 MW of peaking load and 100 MW of long-term unit contingent
15 power supply.

16 Tri-State's Merchant is a network transmission customer of eight
17 Transmission Providers ("TPs") – PAC, PNM, PSCo, TEP, Black Hills Colorado,
18 Platte River Power Authority, Loveland Area Power Authority, and Tri-State
19 Transmission, which purchases point-to-point transmission service from multiple
20 TPs. The Direct Testimony of Mr. Hubbard further describes the Tri-State
21 Transmission network.

22 The Direct Testimony of Mr. Thompson identifies the Tri-State system
23 topology inclusive of multiple BAs and TPs, which maps the load pockets, resource

locations, and Tri-State Merchant's transmission service rights within the system into the resource planning model for each planning region.

Q: HOW DOES THE COMPLEXITY OF TRI-STATE'S SYSTEM IMPACT ITS ERP PROCESS?

A: As described above, Tri-State operates a complex multi-state system to reliably provide service to its Members, maintain compliance with all applicable federal, state, and local rules, minimize costs as a not-for-profit supplier, and meet environmental responsibility commitments and Member expectations. Tri-State's operations allow it to be a supplier that can maximize the benefits of a diverse and geographically dispersed system for the shared benefit of its Members. To enable these benefits, Tri-State's generation and transmission resources are operated as a system. With this system-wide operational approach, Tri-State reviews and develops its resource plans on a system-wide basis; the same is true for this plan, which is focused on demonstrating compliance with Colorado's ERP requirements.

III. 2023 ERP POLICY FRAMEWORK

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: The purpose of this section of my Direct Testimony is to provide an overview of the ERP process, the objectives of Tri-State's 2023 ERP, as well as how the 2023 ERP compared to Tri-State's inaugural 2020 ERP. The electric resource planning process is the standard for determining generation procurement needs, or identifying modifications to existing generation resources, in Colorado under a regulated model. In this case, Tri-State has put to work this now established process to advance both Colorado's and Tri-State's emissions reduction objectives

and energy policy goals.

Q: PLEASE DESCRIBE THE PHASE I PROCESS.

A: Phase I identifies generation quantities (MW), resource types (technologies), and timing of resource needs for meeting load requirements through the modeling of an expansion plan which must meet certain performance criteria and policy objectives. As described in the Direct Testimony of Mr. Hubbard, Tri-State's transmission planning processes are separate from the ERP. While the ERP does include indicative transmission expansion needs associated with generation planning, as well as forecasted costs for upgrades, it is not a comprehensive transmission planning analysis. The focus of Phase I of the ERP is to assess generation needs and determine resource plans.

Q: PLEASE DESCRIBE THE PHASE II PROCESS.

A: As part of a Phase II process, Tri-State will be implementing a competitive solicitation process for new resources, as well as evaluating and developing portfolios of bids that meet Tri-State system needs and Commission directives through the ERP. Tri-State has proposed the use of an IE to oversee this Phase II process, as described in the Direct Testimony of Ms. Hunter. Subsequently, Tri-State may pursue the acquisition of additional resources identified in its RAP Action Plan through any necessary Certificate of Public Convenience and Necessity ("CPCN") proceedings and/or via PPAs.

a. 2020 ERP

Q: THIS IS TRI-STATE'S SECOND ERP. PLEASE PROVIDE A SUMMARY OF TRI-STATE'S 2020 ERP IN PROCEEDING NO. 20A-0528E.

1 A: As part of Tri-State's inaugural ERP in Proceeding No. 20A-0528E, the
2 Commission approved the Unopposed and Comprehensive Settlement Agreement
3 ("2020 ERP Settlement Agreement") which, among other components, approved:
4 Tri-State's Phase I Revised Preferred Plan; a commitment to reduce greenhouse
5 gas ("GHG") emissions related to its wholesale electricity sales in Colorado by 80
6 percent in 2030; a Phase II competitive solicitation for new resources with in-
7 service dates through 2026; as well as a continued robust stakeholder
8 engagement process.

9 **Q: WERE THERE ANY COMMITMENTS MADE WITHIN THE 2020 ERP THAT**
10 **IMPACT TRI-STATE'S 2023 ERP?**

11 A: Yes. As part of the 2020 ERP Settlement Agreement, Tri-State agreed, as part of
12 its 2023 ERP, to update certain resource plan modeling assumptions; continue to
13 apply targets related to GHG emissions, energy efficiency, and demand response;
14 hold meetings with interested stakeholders on certain topics; and model certain
15 stakeholder-requested scenarios. These requirements are outlined in Section
16 3.11 of the 2020 ERP Settlement Agreement.

17 **Q: DOES THE 2023 ERP COMPLY WITH THE 2020 ERP SETTLEMENT**
18 **AGREEMENT COMMITMENTS MADE IN PROCEEDING NO. 20A-0528E?**

19 A: Yes. Fulfillment of each of these obligations is identified and described in the
20 compliance matrix provided as ~~Attachment A to the ERP (Attachment LKT-1)~~.

Attachment LKT-5

21 **b. Key Objectives and Considerations**

22 **Q: WHAT ARE TRI-STATE'S KEY OBJECTIVES WITHIN THE 2023 ERP?**

23 A: The ERP process is a vehicle to vet and advance the changes that Tri-State

1 Members and interested stakeholders should anticipate in the coming years. With
2 this 2023 ERP, Tri-State will ensure reliability and resource adequacy, maintain
3 affordability for Members, and meet compliance obligations, including those
4 related to environmental responsibility. Tri-State also feels it is important to reflect
5 key Responsible Energy Plan (“REP”) objectives, which are the basis of Tri-State’s
6 overarching strategy, within its resource plan. The backdrop for these objectives
7 is a generation fleet that is changing significantly during the turn-of-the-decade—
8 a timeframe that is encapsulated within the 2023 ERP’s RAP. Our system also
9 faces unique challenges and opportunities in its operations—being in the desert
10 West, facing emerging extreme weather conditions, and having a multi-state
11 system with complex load, resource, and market dynamics.

12 **Q: PLEASE IDENTIFY ANY OTHER POLICY OBJECTIVES RELEVANT FOR THIS**
13 **ERP.**

14 A: GHG emission reduction targets as established in the 2020 ERP Settlement
15 Agreement are met and exceeded in our 2023 ERP. Tri-State aims to leverage
16 benefits under the Inflation Reduction Act of 2022 (“IRA”) to further accelerate REP
17 goals related to environmental responsibility and Member flexibility, while
18 maintaining an affordable and reliable system. Reliability metrics along with
19 extreme weather event impacts are utilized to evaluate and demonstrate reliability
20 and resource adequacy objectives.

21 **Q: HOW HAS TRI-STATE’S RESOURCE MIX CHANGED IN RECENT YEARS?**

22 A: In 2016, Tri-State’s system capacity consisted of 43 percent coal resources, 21
23 percent gas and oil resources, 12 percent firm contract non-renewable resources

1 and 24 percent renewable resources. In 2022, Tri-State system capacity consisted
2 of 34 percent coal resources, 19 percent gas and oil resources, 14 percent firm
3 contract non-renewable resources and 33 percent renewable resources. By 2025,
4 Tri-State anticipates 50 percent of the electricity its Members use will come from
5 clean resources, in alignment with the REP. Tri-State has made progress and is
6 continuing on its path to achieving an 80 percent reduction in GHG emissions
7 regarding wholesale electricity sales in Colorado from a 2005 baseline by 2030
8 and 70 percent clean energy serving Member systems by 2030. The IRA Scenario
9 forecasts an 89 percent reduction in GHG emissions regarding wholesale
10 electricity sales in Colorado from a 2005 baseline in 2030 and approximately 70
11 percent clean energy serving Member systems by 2030.²

12 **Q: AS TRI-STATE MAKES A SIGNIFICANT FLEET TRANSITION OVER THE**
13 **REMAINDER OF THIS DECADE, WHAT OTHER SIGNIFICANT FACTORS**
14 **MUST BE CONSIDERED?**

15 A: Several key factors influence the transition of Tri-State's fleet over the remainder
16 of the decade, those most significant include load reduction as a result of Member
17 exits and Partial Requirements, transition of a portion of Tri-State's load and
18 resources into a regional transmission organization ("RTO"), potential to access
19 IRA funding and the continued need to meet reliability while retiring thermal
20 resources and acquiring resources that are still emerging technologies.

21 **Q: WHAT CHANGES TO TRI-STATE'S SYSTEM LOAD ARE TAKING PLACE**

² Figure 5 of the ERP Report (**LKT-1**) identifies the IRA Scenario system energy mix for sales to Members and non-Members.

SINCE TRI-STATE'S 2020 ERP?

A: The most significant change between our 2020 ERP and the 2023 ERP is the reduction in load modeled throughout most of the Resource Planning Period ("RPP") resulting from the planned exit of three Tri-State Members in 2024 and 2025.³ These Members, combined, represented 21 percent of Tri-State's load, primarily in Colorado. The Direct Testimony of Ms. Lynn provides further detail on the process for developing the load forecasts used for the 2023 ERP modeling. Despite the reduced load, new resource acquisitions planned during the RAP are still robust due to the drive to reduce GHG emissions while bringing on resources to reliably integrate renewables, with the assistance of potential Empowering Rural America ("New ERA") funding from the U.S. Department of Agriculture ("USDA").

Q: ARE THERE PLANNED MEMBER EXITS THAT IMPACT SYSTEM LOAD FOR THE DURATION OF THE 2023 ERP PLANNING PERIOD?

A: Yes. United Power has provided an unconditional notice to exit on May 1, 2024 and Mountain Parks has provided an unconditional notice to exit on February 1, 2025. The load associated with these Member Systems is removed from the 2023 ERP load forecast, on their respective dates, reducing system capacity and energy requirements in the RPP.

c. Federal and State Legislation Impacting the 2023 ERP

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: In this section of my Direct Testimony, I describe the various federal and state laws

³ ERP modeling reflects United Power and Northwest Rural Public Power District exiting May 1, 2024 and Mountain Parks exiting February 1, 2025. See also **Attachment B of the ERP Report (LKT-1)**. **LKT-7**

1 that impact Tri-State's 2023 ERP.

2 **Q: HOW DOES THE INFLATION REDUCTION ACT OF 2022 IMPACT TRI-**
3 **STATE'S RESOURCE PLANNING PROCESS?**

4 A: The IRA, passed in 2022, included provisions for \$9.7 billion in direct funding for
5 electric cooperatives transitioning to clean energy ("New ERA Funding"). This
6 unprecedented funding opportunity resulted in two impacts to Tri-State's 2023
7 ERP:

- 8 • Updates to generic resource pricing to reflect the IRA's extension and
9 expansion of tax credits for renewable and storage resources (discussed
10 further in the Direct Testimony of Mr. Thompson), as well as eligibility for
11 Tri-State to receive the tax credits through "direct pay"; and
- 12 • Modeling of an IRA Scenario that reflects Tri-State's pursuit of New ERA
13 Funding as a result of the IRA, which I discuss further below.

14 **Q: PLEASE SUMMARIZE HOW GHG REDUCTION REQUIREMENTS IN**
15 **COLORADO APPLY TO TRI-STATE'S ERP.**

16 A: Significantly, in the 2020 ERP Settlement Agreement, Tri-State committed to GHG
17 reduction targets for the years 2025, 2026, 2027, and 2030 for its wholesale sales
18 of electricity in Colorado, relative to a 2005 baseline. These targets include GHG

1 reductions of:

- 2 • A twenty-six percent (26%) in 2025;
- 3 • a thirty-six percent (36%) in 2026;
- 4 • a forty-six percent (46%) in 2027; and
- 5 • an eighty percent (80%) in 2030.

6 Tri-State's 2030 target is aligned with § 25-7-105(1)(e)(VIII)(I), C.R.S. which
7 requires wholesale generation and transmission ("G&T") cooperatives to file an
8 ERP that achieves at least an 80 percent reduction in GHG emissions associated
9 with Colorado sales by 2030, relative to a 2005 baseline.

10 **Q: IS TRI-STATE REQUIRED TO FILE A CLEAN ENERGY PLAN?**

11 A: No, Tri-State is not statutorily required to submit a Clean Energy Plan ("CEP") and
12 has not done so here since Tri-State is not a qualifying retail utility.

13 **d. Stakeholder Engagement**

14 **Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

15 A: In this section of my Direct Testimony, I describe Tri-State's ongoing efforts at
16 creating a continued, robust stakeholder collaboration process.

17 **Q: HAS TRI-STATE BEEN ENGAGING WITH STAKEHOLDERS SINCE THE 2020**
18 **ERP IN PROCEEDING NO. 20A-0528E?**

19 A: Yes. Throughout Proceeding No. 20A-0528E, Tri-State held approximately two
20 dozen stakeholder meetings in order to solicit input regarding Phase I
21 supplemental modeling and Phase II modeling assumptions and portfolio analysis,
22 among many other topics. Even prior to the conclusion of the 2020 ERP, in
23 January 2023, Tri-State began convening stakeholder meetings to discuss Phase

1 I scenario development, modeling assumptions, sensitivity analyses, and other
2 topics of interest. We have involved interested stakeholders in the technical details
3 of our data and modeling approaches and have considered and adopted many of
4 their ideas along the way. We appreciate the participation of the state agencies,
5 environmental organizations, developers, and our Members in our resource
6 planning process. We convened more than a dozen of the stakeholder meetings
7 prior to beginning modeling, and several meetings after beginning. Some of these
8 meetings served to fulfill commitments Tri-State made through the 2020 ERP
9 Settlement Agreement, but most were set outside those parameters and pursued
10 in the spirit of collaboration and consensus-building. The full list of stakeholder
11 meetings convened is provided in the ERP Report (**LKT-1**).

12 **Q: HAS THIS APPROACH BEEN SUCCESSFUL?**

13 A: Yes. Tri-State has continuously employed a philosophy of transparency,
14 education, and collaboration in the development of its ERP and Tri-State is proud
15 to have fostered beneficial partnerships with the stakeholders engaged in its ERP
16 processes.

17 **IV. 2023 ERP: PLANNING PERIOD, ASSESSMENT OF EXISTING RESOURCES**

18 **Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

19 A: In this section of my Direct Testimony, I discuss the RAP and planning period that
20 Tri-State proposes to use for the 2023 ERP.

21 **Q: PLEASE EXPLAIN THE SIGNIFICANCE OF THE RAP.**

22 A: The RAP is a period of time over which Tri-State acquires generation resources to
23 meet its resource needs, which is typically between six and 10 years, pursuant to

1 Commission rules.

2 **Q: PLEASE EXPLAIN THE SIGNIFICANCE OF THE RPP.**

3 A: The RPP provides for the period of time over which Tri-State models its resource
4 plan, as well as the period of time in which the costs and benefits of new resources
5 and resource retirements are evaluated by Tri-State.

6 **Q: WHAT RPP DID TRI-STATE MODEL FOR THE 2023 ERP?**

7 A: Tri-State has modeled a planning period of 2024 through 2043, consistent with
8 Rule 3602(k), which specifies "...the planning period is twenty to forty years and
9 begins from the date the utility files its plan with the Commission." In his Direct
10 Testimony, Mr. Thompson discusses the technical and analytical approach to
11 resource plan modeling.

12 **Q: WHAT RAP IS TRI-STATE PROPOSING IN THE 2023 ERP?**

13 A: The RAP proposed by Tri-State is six years, from 2026 through 2031, consistent
14 with Rule 3602(n). Tri-State's acquisition process for addressing the resource
15 needs selected in the RAP, and the resulting RAP Action Plan are described in the
16 Direct Testimony of Ms. Hunter.

17 **Q: WHY DID TRI-STATE SELECT A SIX-YEAR RAP?**

18 A: As Tri-State approaches the end of the decade, a time when a significant amount
19 of baseload power is anticipated to retire and renewable and semi-dispatchable
20 resources are anticipated to come online to meet Colorado's emission reduction
21 goals, there must be a plan in place for ensuring sufficient dispatchable
22 replacement capacity to continue to meet Tri-State's Member load needs reliably.
23 Tri-State's next ERP will not occur until 2027, and at that time, a Phase II would

1 not be concluded with sufficient time to enable the permitting, procurement, and
2 construction steps necessary to bring such resources online prior to the end of the
3 decade. Planning for resources to be in place now for this unprecedented resource
4 shift is essential to meeting reliability requirements.

5 **Q: DID TRI-STATE CONSIDER A LONGER RAP?**

6 A: While Tri-State must plan for the significant resource shift in the coming years, Tri-
7 State must also carefully pursue capital expenditures at a pace that is reasonable
8 in terms of the resulting financial impact to Tri-State Members. Therefore, a six-
9 year RAP strikes the right balance in addressing near-term planning needs.

10 **Q: ARE THERE SIGNIFICANT DIFFERENCES IN THE APPROACH TO THE RAP**
11 **FOR THE 2023 ERP COMPARED TO THE 2020 ERP?**

12 A: Yes, there are two key changes in Tri-State's approach to the RAP. Tri-State's
13 RAP in the 2020 ERP was limited to renewable and storage resources, and while
14 the 2023 ERP will continue to seek procurement of those resources, it will also
15 include opportunity for new innovative technologies⁴ and address the need for a
16 dispatchable natural gas resource. Also, Tri-State intends to leverage IRA funding
17 to enable Tri-State to take significant steps forward in achieving its REP objectives
18 during the RAP.

19 **a. Generation Capacity Needs**

20 **Q: HOW DID TRI-STATE ASSESS WHETHER ADDITIONAL GENERATION**
21 **CAPACITY IS NEEDED FOR SYSTEM RELIABILITY?**

22 A: Tri-State forecasts whether sufficient planning reserve margin ("PRM") is

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⁴ See **Attachment C-2 of the ERP Report (LKT-1)** for description of the innovative technology options being modeled in the 2023 ERP.

1 maintained throughout each summer peak season during the RAP, as well as
2 assessing system performance under modeled extreme weather event (“EWE”)
3 conditions, in order to sufficiently make this determination. In addition to system
4 resources achieving the minimum PRM, they must also meet several additional
5 minimum reliability metrics. Tri-State has worked with its stakeholders to identify
6 appropriate Level I and II reliability metrics, discussed further below.⁵

7 **Q: PLEASE EXPLAIN THE PLANNING RESERVE MARGIN.**

8 A: Planning reserve margin is the amount of generation capacity in excess of peak
9 firm obligation load that a utility must carry on its system in order to meet Member
10 demand and firm sales, including under system uncertainties. Tri-State’s PRM is
11 22 percent initially transitioning to 30.5 percent upon the retirement of Craig
12 station, as determined by the Effective Load Carrying Capability and Reserve
13 Margin Study (“ELCC/PRM Study”) completed by Astrape August 2023
14 (**Attachment G-1** of the ERP Report). The ELCC/PRM Study is described further
15 in the Direct Testimony of Brian Thompson.

16 **Q: HAS TRI-STATE PROVIDED AN ASSESSMENT OF ITS EXISTING**
17 **RESOURCES PER RULE 3605(c)?**

18 A: Yes. Tri-State has provided its assessment of existing resources within
19 **Attachment LKT-17** ~~Attachment LKT-1 (LKT-1 Attachment C-3)~~. This assessment identifies the key
20 operational and environmental features, and facility characteristics of all owned
21 and purchased generation resources. In addition, Black & Veatch completed an
22 assessment of the performance and financial characteristics of Tri-State

⁵ See ERP Report (**LKT-1**) for a description of Level I and II reliability metrics for the 2023 ERP.

1 generation. Tri-State owns or co-owns coal and natural gas units located
2 throughout its four-state system and has a growing supply of renewable resources
3 through purchased power agreements. Several of Tri-State's natural gas
4 combustion turbines are dual-fuel capable, with the ability to operate on fuel oil in
5 cases of natural gas supply or market volatility, providing additional resource
6 flexibility—which has been useful in historical EWE conditions. Tri-State has also
7 recently taken steps in the fall of 2023 toward regulatory approval of construction
8 of its first solar projects,⁶ and plans to expand its ownership of resources to include
9 storage through procurements in Phase II of the 2023 ERP, as described further
10 below and in the Direct Testimony of Susan Hunter.

11 Tri-State has remained capacity-long in recent years and, with its diverse
12 supply and system geography, has not experienced and does not anticipate
13 resource adequacy concerns. Additional detail on Tri-State's existing resources
14 can be found in **Attachments** ~~C-3 and G-2 of the ERP Report (LKT-1)~~ ^{LKT-17 and LKT-30} as well as
15 in the Direct Testimony of Mr. Thompson.

16 As described above, Tri-State is planning for an unprecedented resource
17 shift at the end of this decade, as are many utilities, to meet our environmental
18 responsibility commitments. Following our REP commitment, our in-state coal fleet
19 will be fully retired in 2028. This shift places additional pressure on the
20 performance of our aging gas fleet along with intermittent performance of
21 renewable resources to maintain reliability. With these significant portfolio
22 changes, this ERP highlights the emerging importance of maintaining sufficient

⁶ See Proceeding No. 23A-0548E.

1 dispatchable capacity, the role of advanced energy storage systems, and
2 expanded access to energy markets to continue to meet the reliability standards
3 expected by all of our Members.

4 **Q: IS TRI-STATE TAKING STEPS TO MAXIMIZE THE VALUE OF ITS EXISTING**
5 **RESOURCES' INTERCONNECTION FOR PURPOSES OF THE 2023 ERP?**

6 A: Yes. As stated in Tri-State's RFPs, provided as **Attachments SKH-3, SKH-4, and**
7 **SKH-5**, Tri-State is encouraging bidders in its 2023 ERP Phase II process to offer
8 renewable resources at existing Tri-State owned peaking resource locations with
9 the intent of utilizing surplus interconnection service at those locations if the bids
10 are selected in Phase II modeling. This allows the use of existing interconnections
11 to integrate additional renewable resources while maintaining the ability to dispatch
12 thermal resources for reliability or economic needs when intermittent resources
13 are not available. The Direct Testimony of Ms. Hunter and Mr. Hubbard provide
14 additional detail on surplus interconnection and its anticipated use in the 2023 ERP
15 Phase II process.

16 **b. Forecasted Resource Need**

17 **Q: HAVE THERE BEEN ANY CHANGES TO TRI-STATE'S FORECASTED**
18 **RESOURCE ADDITIONS AND ITS ASSESSMENT OF NEED SINCE**
19 **COMPLETING THE 2020 ERP PHASE II?**

20 A: Yes. The selected 200 MW wind resource in Tri-State's 2020 ERP Phase II
21 procurement, along with the identified backup bid resource, were not available at
22 the accepted bid prices. The wind resource was therefore not reflected in the 2023
23 ERP Phase I modeling. Tri-State has terminated the Coyote Gulch PPA due to

1 the delayed status of the project. However, due to timing of the decision, Coyote
2 Gulch was included in Phase I modeling. A replacement solar resource will be
3 identified for procurement through Phase II of the 2023 ERP. Due to the inclusion
4 of known Member exits and anticipated Partial Requirements load, along with
5 changing resource economics, modeling shows an earlier date for the retirement
6 of Craig 3 of January 1, 2028. These and other factors, such as updated base
7 modeling input assumptions, are driving a significantly different resource need as
8 compared to the 2020 ERP.

9 **Q: WHAT IS TRI-STATE'S FORECASTED RESOURCE NEED FOR THE 2023**
10 **ERP?**

11 A: Tri-State's preferred plan, the IRA Scenario described below, identifies a need for
12 290 MW of dispatchable capacity, 940 MW of renewable resources, and 310 MW
13 of battery storage during the RAP.

14 **V. 2023 ERP SCENARIO MODELING AND RESULTS**

15 **a. Modeling**

16 **Q: DID TRI-STATE CONVENE STAKEHOLDER MEETINGS TO DISCUSS**
17 **SCENARIO MODELING FOR THE 2023 ERP?**

18 A: Yes, Tri-State initiated a transparent and cooperative stakeholder engagement
19 process in advance of 2023 ERP modeling to identify scenarios and sensitivities
20 to be modeled. Tri-State committed to hold at least two meetings with interested
21 stakeholders in advance of beginning Phase I modeling for the next ERP, with the
22 intention of collaboratively identifying scenarios to be modeled.⁷ Tri-State held

⁷ Settlement Agreement, Section 3.11.12.

1 more than the minimum number of meetings and also provided flexibility in
2 determination of stakeholder-requested scenarios to be modeled by providing
3 stakeholders with a preview of certain Business As Usual Scenario modeling
4 outputs to assist in their assessment of useful modeling parameters for other
5 scenarios.

6 Additionally, as described above, Tri-State undertook a comprehensive
7 effort to transparently share modeling input assumptions and educate
8 stakeholders on the continued and evolving complexities of the Tri-State system.
9 Details on the numerous stakeholder meetings convened can be found in the ERP
10 Report (**LKT-1**).

11 **Q: PLEASE DESCRIBE THE SCENARIOS AND SENSITIVITIES MODELED FOR**
12 **THE 2023 ERP.**

13 **A:** Tri-State modeled five scenarios for Phase I of the 2023 ERP, including:

- 14 1. Business As Usual ("BAU");
- 15 2. Inflation Reduction Act ("IRA");
- 16 3. Early Springerville 3 Retirement ("ESPV3");
- 17 4. System-Wide Emissions Reduction ("SWER"); and
- 18 5. Aggressive Colorado Emissions Reduction ("ACER").

19 Base modeling assumptions for each scenario are identified in **Attachment B** of
20 ~~the ERP Report (**LKT-1**)~~, with the assumptions unique to each scenario identified
21 in **Attachment B-3** of ~~the ERP Report (**LKT-1**)~~. Tri-State also conducted two
22 sensitivity analyses on each scenario, including:

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1 1. Extreme Weather Event (“EWE”) Analysis; and

2 2. High Gas (“HG”) Analysis.

3 The Direct Testimony of Mr. Thompson describes the approach to modeling
4 the scenarios and sensitivities using the EnCompass software, as well as the
5 modifications to the approach to EWE modeling made since the 2020 ERP.

6 **Q: DID TRI-STATE MODEL STAKEHOLDER-REQUESTED REDUCTIONS OR**
7 **ELIMINATIONS OF COAL UNITS IN AT LEAST ONE SCENARIO?**

8 **A:** Yes, pursuant to Section 3.11.14 of the 2020 ERP Settlement Agreement, Tri-State
9 convened stakeholder meetings to discuss 2023 ERP Phase I scenarios and
10 modeling assumptions, including retirement date windows to be modeled for
11 certain coal units. These meetings also served to address the Commission’s
12 request in Decision No. C23-0437⁸ to “...work with interested parties to refine
13 modeling assumptions and practices in an attempt to forge as great a degree of
14 consensus as possible, by using its model to analyze the benefits and costs
15 associated with various retirement dates for Craig Unit 3, including identifying
16 economically optimal retirement dates as part of the direct case in its 2023 ERP.”

17 **Q: WHICH OF THE SCENARIOS AND SENSITIVITIES DID TRI-STATE FIND TO**
18 **BE MOST INFORMATIVE FOR ITS RESOURCE PLANNING?**

19 **A:** The IRA Scenario as compared to the ESPV3 Scenario showed more robust
20 emissions reductions during the RAP while allowing for a diversified resource mix
21 during the same period, to both meet reliability and allow for a potential
22 replacement energy sale to the third-party off taker of Springerville 3 after its

⁸ Decision No. C23-0437, at ¶77 (Proceeding No. 20A-0528E).

1 retirement. Without these resources ESPV3 relies on an estimated penalty⁹
2 related to the third-party sale which impacts the affordability of the scenario and
3 drives the Springerville 3 retirement date selected in the ESPV3 scenario to the
4 latest date the model was given.¹⁰ Despite having more aggressive Colorado or
5 system emissions reductions, ACER and SWER Scenarios have less Colorado
6 GHG reductions by 2030 than the IRA Scenario.

7 The IRA Scenario positions Tri-State to meet current environmental targets
8 with the ability to respond to additional environmental legislation or regulation. The
9 EWE sensitivity performed on each scenario provides reasonable certainty of
10 reliability of service to Tri-State Utility Member Systems during likely future weather
11 events. All scenarios successfully passed required reliability metrics during the
12 RAP in their respective EWEs, even with minimal resource additions due to Tri-
13 State's current and evolving capacity length spurred by Member exits and other
14 load reductions. The IRA Scenario secures significantly larger quantities of
15 resources during the RAP, adding diversity in resource location and technology
16 types which can bolster system performance during EWEs.

17 **Q: ARE THERE CONSISTENT RESULTS ACROSS ALL SCENARIOS THAT**
18 **INFORM THE RESOURCE PLAN?**

19 **A:** Yes. In every scenario modeled, the retirement date for Craig 3 is January 1, 2028.

20 This is a change from the 2020 ERP. Decision No. C23-0437¹¹ directed Tri-State

⁹ The estimated penalty is a proxy for what might possibly be required by the third-party to exit the contract without replacement energy. Tri-State cannot exit the third-party sale without reaching agreement with the impacted party.

¹⁰ Unique scenario modeling assumptions are identified in **Attachment B-3 of the ERP Report (LKT-1)**.

¹¹ ¶ 77, Proceeding No. 20A-0528E.

1 to “evaluate alternate retirement dates for Craig Unit 3 in its 2023 ERP
2 filing...including identifying economically optimal retirement dates as part of the
3 direct case it will file in its 2023 ERP.” Tri-State’s 2023 ERP modeling clearly
4 indicates that January 1, 2028 is the optimal retirement date for Craig 3.
5 Additionally, all scenarios modeled recognize the need for a dispatchable gas
6 resource in the Western Colorado planning region during the RAP. These are
7 significant outcomes that support Tri-State’s preferred plan.

8 **b. Preferred Plan: IRA Scenario**

9 **Q: WHICH SCENARIO DOES TRI-STATE SUPPORT AS ITS RESOURCE PLAN?**
10 **PLEASE EXPLAIN.**

11 A: Tri-State requests Commission approval of the IRA Scenario as its 2023 ERP
12 Phase I preferred plan. The IRA Scenario, as discussed in the following sections,
13 meets core reliability, financial and environmental metrics that are essential to Tri-
14 State Members. In particular, the financial benefits of pursuing this scenario that
15 cannot otherwise be captured without capitalizing on this one-time window for
16 federal funding, far exceed the benefits of any other scenario modeled.

17 **Q: WHAT ARE THE CORE ELEMENTS OF THE IRA SCENARIO?**

18 A: The IRA Scenario retires 1,207 MW (nameplate – 1,067 net MW) of coal-fired
19 generation during the RAP. Under the IRA Scenario, if USDA funding is received
20 as requested and if contractual commitments are adequately addressed, Tri-State
21 intends to announce a retirement date of 2031 for the coal-fired Springerville
22 Station Unit 3 (458 MW nameplate capacity). This is a dramatic acceleration from
23 its expected operating life of 2066. Additionally, the IRA Scenario further

1 accelerates the retirement date for coal-fired Craig 3 (535 MW nameplate capacity)
2 by two years, to 2028. The IRA Scenario also adds 1,250 MW of renewables and
3 storage between 2024 and 2031, 1,040 MW of those projects are anticipated
4 through PPAs, with 210 MW being build-transfer arrangements. Lastly, the IRA
5 Scenario continues to select a 290 MW dispatchable, natural gas combined-cycle
6 plant for 2028, with conversion to carbon capture and storage capability in 2031.
7 This set of ambitious, near-term resource plan actions is predicated on Tri-State
8 receiving New ERA Funding as requested.

9 **Q: WHAT FACTORS INFLUENCE TRI-STATE'S ABILITY TO IMPLEMENT THE**
10 **IRA SCENARIO?**

11 A: There are several critical path factors that must have favorable outcomes in order
12 for Tri-State to implement the IRA Scenario, these include:

- 13 • New ERA Funding award as requested from USDA;
- 14 • Negotiation of contractual agreements impacted by the resource plan;
- 15 • Affirmation of Tri-State eligibility for U.S. Internal Revenue Service ("IRS")
16 "direct pay" of tax credits;¹² and
- 17 • Phase II bid prices, locations, and commercial operation dates ("CODs")
18 that enable fulfillment of New ERA Funding award obligations and approved
19 resource plan needs.

20 If financially viable through direct pay tax credits, Tri-State may still elect to
21 pursue the approximately 10 MW iron air battery storage project for 2026 without
22 New ERA Funding. This relatively small project is being pursued outside of the

¹² 26 U.S. Code § Section 6417 Elective Payment of Applicable Credits.

1 Phase II procurement process, as discussed in the Direct Testimony of Susan
2 Hunter.

3 **Q: WHAT ACTIONS MIGHT BE TAKEN BY TRI-STATE IF THESE EXTERNAL**
4 **FACTORS IMPACT THE VIABILITY OF THE IRA SCENARIO?**

5 A: Due to uncertainties related to federal funding and contractual agreements at the
6 time of this filing, Tri-State acknowledges there may be impacts to the resource
7 plan that occur subsequent to the initial filing. If federal funding awarded varies
8 significantly from Tri-State's request to USDA, Tri-State anticipates the need to
9 conduct additional scenario modeling. Such modeling may result in a necessary
10 delay in the procedural schedule for Phase I. Tri-State would collaborate with
11 stakeholders and act expeditiously to complete supplemental modeling to support
12 a timely Phase II that facilitates the target CODs for new projects.

13 **Q: ARE THERE ELEMENTS OF THE IRA SCENARIO THAT ARE NOT IMPACTED**
14 **BY NEW ERA FUNDING OUTCOMES?**

15 A: Yes, the retirement date for Craig Unit 3 is not contingent upon Tri-State receiving
16 New ERA Funding from USDA. This is because the economics of Craig Unit 3's
17 operations during the remaining years of its operations are not influenced by any
18 federal funding.

19 **VI. 2023 ERP PERFORMANCE METRICS**

20 **a. Reliability**

21 **Q: WHAT RELIABILITY METRICS DOES TRI-STATE UTILIZE TO ASSESS**
22 **SCENARIO / SENSITIVITY PERFORMANCE UNDER THE ERP?**

23 A: Tri-State applies two levels of reliability metrics to all scenarios:

- 1 • Level I:
 - 2 o Planning Reserve Requirement (“PRM”) of 22 percent, transitioning to
 - 3 30.5 percent upon the retirement of Craig Station, based upon the third-
 - 4 party ELCC and PRM Study (~~Attachment G-1 of the ERP Report (LKT-~~
 - 5 ~~1))~~);
 - 6 o Loss of load hours (“LOLH”) of no more than 1 day in 10 years;
 - 7 • 2.4 hours per year 2024 to 2033;
 - 8 • 24 hours total 2034 to 2043; and
 - 9 o No more than 0.4 GWh annually of expected unserved energy (“EUE”).
- 10 • Level II:
 - 11 o No more than 12 hours of EUE in 12 EWE from 2026 to 2031;
 - 12 o No more than 3 hours of expected unserved energy in any year during
 - 13 EWE event periods 2026 to 2031; and
 - 14 o EUE in any EWE hour cannot exceed 20 percent of load in that hour.

15 Level I metrics set a baseline that ensures Tri-State resources will meet industry-

16 standard service reliability requirements and Level II metrics provide an added

17 level of assurance of resource adequacy under potential EWE conditions, which

18 are becoming more frequent and extreme. The Commission acknowledged in

19 Decision No. C23-0437 that “...history may not be fully predictive of future weather

20 extremes given climate change...”¹³

21 **Q: HOW WERE THE RELIABILITY METRICS DEVELOPED?**

22 A: Tri-State has long utilized the industry-recognized standards for PRM and LOLH

¹³ Decision No. C23-0437, at ¶ 57 (Proceeding No. 20A-0528E).

1 to establish minimum reliability requirements for its system. Beginning in 2022,
2 Tri-State expanded its ERP modeling process to include EWE analyses, to assess
3 the reliability of its system under potential extreme weather conditions which have
4 been experienced more frequently in recent years. Tri-State developed EUE
5 criteria referred to as “Level II” to further evaluate the reliability and resource
6 adequacy of potential future resource plans. The EWE stress conditions and
7 reliability metrics were shared with stakeholders and discussed over the course of
8 several meetings that were convened prior to and at the start of 2023 ERP
9 modeling, as described in the ERP Report (**LKT-1**). The direct testimony of Brian
10 Thompson further discusses the approach to sensitivity modeling.

11 **Q: WHY IS IT IMPORTANT THAT THE RELIABILITY ASSESSMENT ENSURE TRI-**
12 **STATE HAS RESOURCES SUFFICIENT TO MEET CAPACITY NEEDS**
13 **WITHOUT MARKET RESOURCES?**

14 **A:** First and foremost, Tri-State is a Load Responsible Entity (“LRE”) meaning it must
15 maintain capacity to meet its load and planning reserve needs. Even as a future
16 Market Participant in SPP RTO in the western interconnection, Tri-State will
17 continue to be responsible for its performance obligation as an LRE. Each LRE is
18 required to maintain the total of planning capacity necessary to serve Net Peak
19 Demand (load) and PRM. This is consistent with the 2020 ERP Settlement
20 Agreement at section 3.11.14. which describes certain elements of “Tri-State’s
21 Next ERP Filing,” which commits that “reliability objectives will be satisfied using
22 only Tri-State resources regardless of bilateral or organized market access.”
23 Additionally, Tri-State must also maintain compliance with applicable North

American Electric Reliability Corporation (“NERC”) reliability standards.

Q: DOES THE IRA SCENARIO MEET ALL LEVEL I AND II RELIABILITY METRICS EXPECTATIONS?

A: Yes. Tri-State and its Members would not support any resource plan that did not meet all minimum reliability metric requirements. Not only does the IRA Scenario meet the minimum Level I and II reliability thresholds set, but it also has the highest planning reserve margin during the RAP which gives room to accommodate potential delays with load reductions or in resource acquisition, construction, and commercial operation. The IRA Scenario as modeled, delivers the highest confidence for Tri-State and its Members that the future generation fleet action plan will result in the most reliable system going forward.

b. Financial Results

Q: WHAT KEY CIRCUMSTANCES MUST TRI-STATE CONSIDER WHEN ASSESSING THE FINANCIAL PERFORMANCE OF THE 2023 ERP SCENARIOS?

A: Pursuant to Decision No. C23-0437, Tri-State’s load forecast reflects anticipated member departures at the time of filing. Additionally, as uncertainty remains regarding Tri-State’s Partial Requirements (“PR”) contracts, the load forecast also reflects a one-year delay in anticipated member PR resources coming online (now 2026).¹⁴ Beyond forecasted load needs, Tri-State’s resource plan targets achievement of its Member-driven REP objectives, which include prudently managing costs associated with the energy transition. Tri-State has aggressively

¹⁴ Decision No. C23-0437, at ¶ 63 (Proceeding No. 20A-0528E).

1 pursued federal funding opportunities in recent years to reduce the cost of
2 generation investments for its Members and provided a summary of these pursuits
3 in a March 2, 2023 letter to the Commission in Proceeding No. 23M-0053ALL.¹⁵

4 **Q: HAS TRI-STATE BEEN AWARDED FEDERAL FUNDING SINCE ITS MARCH**
5 **2023 LETTER TO THE COMMISSION?**

6 A: Yes. On October 18, 2023, the U.S. Department of Energy (“DOE”) awarded Tri-
7 State \$26.8 million in funding, subject to final negotiations, under DOE’s Grid
8 Resilience and Innovation Partnerships (“GRIP”) Program. The DOE funding, with
9 an equal match from Tri-State, will support Tri-State’s Cooperative Energy
10 Ecosystem project,¹⁶ which supports deployment of energy efficiency, demand
11 response (“DR”), beneficial electrification, and integration of distributed energy
12 resources; and will accelerate deployment of our new Distributed Energy Resource
13 Management System (“DERMS”). The DERMS platform is anticipated to launch
14 in 2024, as an important component of our plans to achieve the 2025 DR Target
15 identified in our 2020 ERP Settlement Agreement.¹⁷

16 **Q: WHAT OTHER FEDERAL FUNDING HAS TRI-STATE PURSUED SINCE ITS**
17 **MARCH 2023 LETTER TO THE COMMISSION?**

18 A: To support necessary generation investments in the coming years and to assist in
19 alleviating the impact of stranded assets due to coal unit retirements, Tri-State
20 submitted a Letter of Interest to the USDA on September 13, 2023 seeking to
21 leverage the maximum program budget authority of \$970 million in grant and loan

¹⁵ Decision No. C23-0437, at ¶ 86 (Proceeding No. 20A-0528E).

¹⁶ https://www.energy.gov/sites/default/files/2023-10/DOE-GRIP-Tri-State-Generation-and-Transmission-Association_0.pdf.

¹⁷ Section 3.11.8.

1 funding under the USDA's New ERA program, authorized by the IRA.

2 **Q: HOW IS THE FEDERAL FUNDING THAT IS BEING PURSUED BY TRI-STATE**
3 **REFLECTED IN THE ERP?**

4 A: As described above, Tri-State incorporated its requested level of New ERA
5 Funding into the financial modeling completed for the IRA Scenario.

6 **Q: WHICH SCENARIO RESULTS IN THE LOWEST PRESENT VALUE REVENUE**
7 **REQUIREMENT ("PVRR") FORECASTED OVER THE RPP?**

8 A: Given the financial benefit of New ERA Funding assumed for the IRA Scenario, it
9 has the lowest resulting PVRR, \$16,352M.

10 **Q: WHICH SCENARIO HAS THE LOWEST ANNUAL REVENUE REQUIREMENTS**
11 **DURING THE RAP?**

12 A: Given the financial benefit of New ERA Funding assumed for the IRA Scenario, it
13 has the lowest annual revenue requirements.

14 **Q: WHAT DO MODELING RESULTS INDICATE WITH REGARD TO**
15 **CURTAILMENTS?**

16 A: Solar curtailments are highest in the RAP in years 2026 and 2027 for the BAU,
17 ESPV3, SWER, and ACER Scenarios given the growing amount of renewable
18 resource additions on the Tri-State system during that period. The IRA Scenario
19 has the least amount of curtailments on an annual basis during the RAP, with the
20 exception of year 2031 due to resources coming online ahead of SPV3 retirement.
21 Participation in regional organized markets and pursuit of renewable generation
22 ownership will help to mitigate the financial impact of curtailments for Tri-State
23 Members.

1 **c. Environmental Compliance**

2 **Q: PLEASE EXPLAIN TRI-STATE'S GHG TRACKING AND REPORTING**
3 **COMMITMENTS UNDER THE 2020 ERP SETTLEMENT AGREEMENT.**

4 A: Under the 2020 ERP Settlement Agreement, Tri-State committed that, going
5 forward, it will operate its system in a manner that achieves, at a minimum, with
6 respect to its Colorado Air Pollution Control Division ("APCD") verified 2005
7 Baseline, the following reductions in GHG emissions related to Tri-State's
8 wholesale sales of electricity in Colorado (the "Interim-Year Emissions
9 Reductions"): a twenty-six percent (26 percent) reduction in calendar-year 2025; a
10 thirty-six percent (36 percent) reduction in calendar-year 2026; and a forty-six
11 percent (46 percent) reduction in calendar-year 2027.¹⁸ Tri-State also agreed that,
12 going forward, it will operate its system in a manner that achieves, at a minimum,
13 with respect to its APCD verified 2005 Baseline, an eighty percent (80 percent)
14 reduction in GHG emissions related to Tri-State's wholesale sales of electricity in
15 Colorado in calendar-year 2030 ("the 2030 Emissions Reduction").¹⁹

16 The Interim-Year Emissions Reductions and 2030 Emissions Reduction will
17 be calculated and reported consistent with the methodology adopted by APCD for
18 the Verification Workbook.²⁰ In each year following a year in which Tri-State has
19 committed to emissions reductions, Tri-State will report the results of emissions
20 reductions in its ERP Annual Progress Report (the "Annual Progress Report")
21 submitted to the Commission under Rule 3618.²¹

¹⁸ Settlement Agreement, Section 3.3.4.

¹⁹ Settlement Agreement, Section 3.3.5.

²⁰ Settlement Agreement, Section 3.3.6.

²¹ Settlement Agreement, Section 3.3.11.

1 **Q: PLEASE EXPLAIN THE VERIFICATION WORKBOOK.**

2 A: Presently, emissions tracking in Colorado is accomplished primarily through use
3 of the APCD CEP Guidance and Verification Workbook (the “Workbook”). The
4 Workbook includes methodologies for tracking and assigning emission rates to
5 market purchases and sales and for netting market purchase and sales activity at
6 the emission rate of the respective market. Tri-State utilized the Workbook to
7 calculate projected emissions in 2030 and other target years for emissions
8 reduction commitments. This practice will continue for forecasting and reporting
9 emissions and Tri-State anticipates using the APCD Workbook to report actual
10 emissions for target years as part of its 2023 ERP Annual Progress Report
11 beginning with reporting for target year 2025.

12 The CEP Guidance provides a standardized format for utilities to submit
13 data and information so that the APCD may verify the emissions reductions, as
14 required under SB-236 and HB-1261. The CEP Guidance includes a qualitative
15 narrative of the purpose and details of the guidance, which includes three
16 appendices: (1) Appendix A: which establishes the APCD’s role and
17 responsibilities in the ERP process; (2) Appendix B, a Verification Workbook,
18 which collects data related to both the Phase I and Phase II of the ERP process;
19 and (3) Appendix C: Adjusted Baseline and Comprehensive Safe Harbor Proposal.

20 The Workbook provides the basis for the APCD to perform emission
21 reductions verification, as well as a high level of transparency while also providing
22 clarity and certainty an ERP evaluation. Further, the Workbook establishes carbon
23 accounting protocols, including transparent accounting for any baseline

adjustment requirements.

Q: HAS TRI-STATE COMPLETED AN APCD WORKBOOK FOR EACH SCENARIO MODELED?

A: Yes, pursuant to Sections 3.11.1. and 3.11.3. of the 2020 ERP Settlement Agreement, Tri-State has completed an APCD Workbook for each Scenario modeled, provided in **Attachment D of the ERP Report (LKT-1)**. Additionally, Tri-State has utilized the APCD Workbook methodology to calculate emissions reductions forecasted on a system-wide basis for the System-Wide Emissions Reduction Scenario; however, Tri-State is not seeking verification from APCD for that workbook given that it is outside the scope of Colorado rules and regulations.

Q: DO ALL OF THE SCENARIOS MODELED ACHIEVE TRI-STATE'S COLORADO GHG REDUCTION TARGETS?

A: Yes, section 3.3.7. of the 2020 ERP Settlement Agreement identifies that Tri-State's Colorado GHG Targets will be incorporated into Tri-State's future ERP filings as a binding requirement. As shown in the **Attachment D** files, all of the scenarios meet or exceed Tri-State's Colorado GHG Targets. Notably, the IRA Scenario meets the targets and exceeds the 2030 target at the lowest cost.

Q: DID TRI-STATE MAKE ANY SIGNIFICANT UPDATES IN ITS APPROACH TO EMISSION RATES OR DATA INPUTS FOR THE APCD WORKBOOKS?

A: Yes, Tri-State made necessary adjustments to the 2005 baseline and updated certain emissions rates used in the Workbook. First, the 2005 baseline was updated to address load reductions from Member exits and timing changes of

1 Partial Requirements in Colorado. The reduced load forecast²² for the planning
2 period starting in 2025 (Member exits) and 2026 (Partial Requirements) results in
3 a need to correspondingly adjust the 2005 Baseline in the Workbooks. Upon those
4 Colorado Member exits and implementation of Partial Requirements elected by
5 Colorado Members, Tri-State will no longer be responsible for emissions and
6 emissions reductions associated with those loads. The 2005 Baseline used for
7 determination of emissions reductions for 2025 adjusts for the Member exits only,
8 as the Partial Requirements contracts are not anticipated to begin until 2026.
9 Partial Requirements Members can select MAX (Firm capacity) or MARS
10 (intermittent resource) options, where only the MAX selections reduce the system
11 capacity that Tri-State is responsible – currently forecasted as 163 MW, 86 MW of
12 which is related to Members in Colorado. The Workbook accounts for the impacts
13 of 117 MW of the MARS option as a renewable resource.

14 This timing of load changes required the development of a second 2005
15 Baseline calculation for use in determining emission reductions for years after
16 2025; therefore, each Workbook includes two 2005 Baseline tabs—one used for
17 2025 emission reduction calculations, and one used for all other years' emissions
18 reduction calculations. Additionally, market and contract emissions rates were
19 updated to reflect the latest eGrid rates.

20 **Q: DID STAKEHOLDERS REQUEST THE MODELING OF GHG REDUCTIONS**
21 **BEYOND THE REQUIREMENTS OF THE 2020 ERP SETTLEMENT**
22 **AGREEMENT OR COLORADO LAW?**

²² Decision No. C23-0437 at Paragraph 63 directs that Tri-State “submit a load forecast that is indicative of anticipated member departures at the time of filing.”

1 A: Yes. Some stakeholders requested that Tri-State model two scenarios (Scenarios
2 4 SWER and 5 ACER) in Phase I of the 2023 ERP that achieve GHG reductions
3 beyond legislative or regulatory commitments. These scenarios include a scenario
4 with minimum Tri-State system-wide GHG reduction targets over the RAP and a
5 scenario with more aggressive Colorado GHG reductions.

6 **Q: WHAT CONCERNS DOES TRI-STATE HAVE WITH REGARD TO SCENARIOS**
7 **4 (SWER) AND 5 (ACER)?**

8 A: Tri-State is concerned with the potential lack of fairness and consistency that could
9 result for its Members if they were to be involuntarily held to 2030 emissions
10 reduction targets more aggressive than those applicable to all Colorado utilities
11 under current law. Complications may also arise from Colorado regulatory actions
12 that would seek to extend emissions policies beyond the borders of Colorado.
13 Furthermore, it is also possible that adoption of more aggressive emissions
14 reduction targets, beyond those agreed to in the 2020 ERP Settlement Agreement,
15 could conflict with Section 3.3.8. of the agreement which specified that “the Settling
16 Parties agree that Tri-State retains sole discretion over the resource dispatch
17 decisions used to achieve the Interim-Year Emissions Reductions.” Lastly, it would
18 appear imprudent to hastily adopt more aggressive emissions reduction targets at
19 a point in time when not even the first year of the targets has come to pass, for
20 commitments made less than two years ago.

21 **VII. RESOURCE ACQUISITION PLAN**

22 **Q: WHAT SIGNIFICANT ELEMENTS OF TRI-STATE’S ACQUISITION APPROACH**
23 **ARE NEW FOR THE 2023 ERP?**

1 A: In the 2020 ERP Phase II, Tri-State utilized a single RFP for renewable and storage
2 PPA resources only for the 2025-26 period, indicating Tri-State did not intend to
3 pursue self-build or ownership options for resources at that time²³ and agreeing to
4 a limited procurement window²⁴ given load uncertainties and its capacity-long
5 position. The 2020 ERP Phase II procurement and modeling process resulted in
6 identification of the need to procure only one 200 MW wind resource within that
7 two-year period.

8 However, since that time, load requirements are being modified going
9 forward, dispatchable resources are being retired during the RAP, a myriad of
10 updated modeling assumptions such as new effective load carrying capabilities
11 (“ELCCs”) are being created, as well as the financial implications resulting from
12 the IRA. As such, Tri-State’s 2023 ERP procurement strategy has substantially
13 changed since Tri-State’s last ERP.

14 Additionally, it is now imperative, in order to maintain system reliability while
15 procuring renewable and semi-dispatchable innovative technologies to replace
16 retiring generation, to procure a new dispatchable resource. Given these
17 conditions, Tri-State intends to issue three RFPs in Phase II of the 2023 ERP –
18 one for storage resources to be owned by Tri-State as a result of build-transfer
19 (“BT”) agreements or by working with an EPC contractor, one for a dispatchable
20 gas resource, with ability to convert to accommodate carbon capture and
21 sequestration (“CCS”), to be owned and constructed by Tri-State working with an

²³ See Hearing Exhibit 106, Direct Testimony and Attachments of Susan K. Hunter, Proceeding No. 20A-0528E at 7: 8-9.

²⁴ Settlement Agreement, Sections 3.4.3. and 3.4.4.

1 EPC contractor, and one for renewable resources to be procured through PPAs.
2 Bid evaluation criteria and screening processes will be similar to the 2020 ERP,
3 but with some updates to reflect lessons learned.

4 **Q: DOES TRI-STATE INTEND ON UTILIZING AN IE FOR THE 2023 ERP?**

5 A: Yes, Tri-State will utilize an IE for the 2023 ERP to add further assurance of
6 consistency and fairness in its bid evaluation process for both BT and PPA
7 agreements. Additional information on Tri-State's Phase II procurement plans,
8 including use of an IE, is provided in the Direct Testimony of Ms. Hunter. Further
9 detail on Tri-State's anticipated approach to acquisition of a new dispatchable gas
10 resource is provided in the Direct Testimony of Mr. Ingold.

11 **Q: WHAT CONSIDERATIONS AND MODELING RESULTS ARE DRIVING THE**
12 **NEED FOR A 290 MW COMBINED CYCLE GAS RESOURCE**
13 **INTERCONNECTING TO TRI-STATE'S SYSTEM IN WESTERN COLORADO?**

14 A: The modeling software assesses resource retirements and acquisitions over the
15 entire resource planning period determining the most economic resource mix given
16 transmission and environmental constraints. Given the retirement of Craig Station
17 by the fall of 2028 including the early retirement of Craig 3 on January 1, 2028,
18 greenhouse gas reduction targets in Colorado, and system GHG reductions
19 targets in the IRA scenario, the model selected the 290 MW combined cycle gas
20 resource in 2028 with conversion to CCS in 2031 to meet capacity and energy
21 needs over the RPP. The IRA Scenario has 1,067 MW of coal retirements over
22 the RAP and the 290 MW NGCC with CCS is the only fully dispatchable resource
23 added to the system. This resource, along with semi-dispatchable batteries, allows

1 for the successful integration of 940 MW of renewables from 2026 to 2031 under
2 the IRA Scenario.

3 **Q: DO OTHER MODELING RESULTS BEYOND THE IRA SCENARIO SUPPORT**
4 **THE NEED FOR A DISPATCHABLE GAS RESOURCE?**

5 A: Yes. While there is slight variation in the date that the model selects a gas
6 resource in each scenario, all five of the scenarios select a gas resource addition
7 during the RAP. In every 2023 ERP Phase I scenario the modeling selected the
8 need for a gas resource in Western Colorado planning region. This is also
9 generally consistent with Tri-State's approved preferred plan and portfolio resulting
10 from the 2020 ERP modeling, which also called for a dispatchable gas resource.²⁵

11 **Q: DOES THE FEDERAL PRODUCTION TAX CREDIT INFLUENCE THE**
12 **SELECTION OF A COMBINED CYCLE RESOURCE WITH CCS?**

13 A: Yes. Section 45Q under Title 26 of the U.S. Code provides for an \$85/tonne
14 production tax credit ("PTC") for sequestered carbon for twelve years once placed
15 in service, with a requirement that construction of CCS must begin by January
16 2033 for PTC eligibility. This tax credit exceeds the forecasted cost of fuel and
17 variable O&M for a combined cycle resource. The result is a baseload
18 dispatchable resource with a minimal carbon footprint at a significantly more
19 affordable operational price point.

20 **Q: WHAT ACQUISITION PROCESS IS TRI-STATE PROPOSING FOR THIS**
21 **RESOURCE AND OTHERS IN THE RAP?**

²⁵ The Phase I Revised Preferred Plan (80pc CR v5) Scenario selected a 290 MW combined cycle gas unit in Western Colorado in 2030. The Phase II Revised Preferred Plan Portfolio selected a 193 MW combustion turbine gas unit in Western Colorado in 2030.

1 A: Tri-State will simultaneously issue three RFPs for Phase II of the 2023 ERP, within
2 30 days of the Commission's final decision on Phase I. One for storage resources,
3 one for dispatchable gas resources with ability to convert to CCS, and one for
4 renewable resource bids. An IE will assist Tri-State in monitoring the application
5 of the bid evaluation criteria and reviewing the analysis of bids through the portfolio
6 modeling. Detailed information on Tri-State's Phase II procurement plans is
7 provided in the Direct Testimony of Ms. Hunter, including draft RFPs, a proposed
8 Phase II timeline, and a Statement of Work for the IE.

9 **Q: HOW DOES THIS PROCESS ENSURE TRI-STATE IS OBTAINING A COST-**
10 **EFFECTIVE RESOURCE FOR ITS MEMBERS?**

11 A: Tri-State is not a publicly-traded entity with stock or shareholders, and therefore
12 does not produce stock earnings as a result of its investments. Tri-State is a not-
13 for-profit entity providing wholesale power under the cooperative principles for the
14 benefit of its Members, which requires Tri-State to provide service at the lowest
15 cost possible while maintaining system reliability standards and achieving
16 environmental responsibility commitments. Not only will the 2023 ERP
17 procurement process be overseen by an IE, but it will be conducted pursuant to
18 Commission rules and with the review and collaboration of numerous interested
19 stakeholders with diverse interests. These realities set the stage for Tri-State to
20 pursue the most cost-effective resource mix that meets our Members' needs,
21 whether through PPAs, build or build-transfer arrangements, or a combination
22 thereof.

23 **Q: WHAT ARE THE KEY FACTORS IN TRI-STATE CONSIDERING ACQUISITION**

APPROACHES?

A: Given the significant opportunities presented by the IRA, it would not be financially prudent for Tri-State to consider a PPA-only procurement strategy. Additionally, with the expansion of new resource types emerging in the 2023 ERP, as well as the planned retirement of Tri-State-owned resources, our procurement strategy seeks to maintain an appropriate balance of owned and contracted resources for serving our Members. The Direct Testimony of Ms. Hunter further expands on the drivers and value in the acquisition approach.

Q: WHAT ARE THE CONSTRUCTION AND SITING CONSIDERATIONS THAT TRI-STATE MUST NOW BEGIN TO TAKE ACTION ON?

A: Tri-State engaged a third-party consultant to conduct a siting study related to the construction of a 290 MW NGCC in 2028 with anticipated addition of CCS in the early 2030s. This study will analyze potential locations for the new resource taking into consideration gas pipeline accessibility, CCS capabilities and transmission interconnection. The resource will be located in electrical west Colorado which is defined as a resource interconnecting to the transmission system west of TOT 5, north of TOT 2, and east of TOT 1. Given those parameters the resource could be located in western Colorado or southern Wyoming. In addition to this initial study and contingent upon Commission approval in Tri-State's 2023 ERP process, Tri-State will need to initiate applicable state regulatory and environmental permitting processes. Anticipated next steps in construction and siting considerations are discussed in the Direct Testimony of Ms. Hunter and Mr. Ingold.

VIII. Organized Market Participation

Q: WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A: The purpose of this section of my Direct Testimony is to provide Tri-State's current market participation status, as well as its future plans to join an RTO and how that will affect future Tri-State resource planning efforts.

Q: PLEASE DESCRIBE TRI-STATE'S CURRENT AND PLANNED MARKET PARTICIPATION.

A: Tri-State's load in PacifiCorp has been in CAISO's Western Energy Imbalance Market ("WEIM") since 2014. Tri-State's load and resources in PNM moved into the WEIM in April 2021. In February 2021, Tri-State's load and resources in WACM began participation in SPP's Western Energy Imbalance Services market ("WEIS"). In April 2023, the remainder of Tri-State's load and resource moved into WEIS with the entry of the PSCO BA into the market. In 2020,²⁶ Tri-State announced its intention along with other western entities to explore transitioning its load and resources in the WACM BA into the SPP RTO. In June 2022, Tri-State's Board signed a commitment, along with other western entities, to transition load and resources in WACM into the SPP RTO by April 1, 2026. More information on this transition is available in Proceeding No. 23M-0195E. We also continue to monitor developments in the Markets+ arena given the potential for Tri-State load and resources in other BAs to join that market.

Q: DOES TRI-STATE ACCOUNT FOR ITS PLANNED RTO PARTICIPATION IN ITS

²⁶ <https://www.tristate.coop/spp-and-stakeholders-will-consider-rto-expansion-west-study-anticipates-49m-annual-savings-current>.

MODELING?

A: While Tri-State has not yet implemented a nodal model that would be required to fully represent markets in its resource plan modeling, Tri-State has analyzed and expanded market depths (sales and purchase) levels in its model to represent the WACM BA transition to SPP RTO in 2026, expected transition of PSCO and PNM to an RTO in 2030. Market depth assumptions are identified in **Attachment ~~B~~ of ^{LKT-7} the ERP Report (LKT-1)**. The testimony of Mr. Thompson further describes Tri-State's approach and assumptions regarding market depths and RTO market products used in the 2023 ERP modeling.

Q: FROM A POLICY PERSPECTIVE, HOW DOES ORGANIZED MARKET PARTICIPATION IMPACT TRI-STATE'S RESOURCE PLANNING?

A: Participation in an organized market allows for the more efficient, cost-effective use of resources including the ability to better integrate a large quantity of intermittent renewable resources. Access to a larger footprint and collective use of transmission within the footprint allows for a decrease in the curtailment of renewable resources. Additionally, market optimization over a larger footprint allows for diversity of region and resources to shore up reliability while utilizing transmission in a manner to produce the most economic dispatch, increasing affordability.

IX. LOAD AND RESOURCE BALANCE

Q: WHAT DOES TRI-STATE'S LOAD AND RESOURCE BALANCE INDICATE?

A: As shown in the ERP Report (**LKT-1**), Tri-State's load and resource ("L&R") balance forecasts, without any new resource additions, Tri-State would continue

1 to be resource-long until 2029. With the resource additions planned under the IRA
2 Scenario, our resource-long position will extend through the planning period.

3 **Q: WHAT ARE SOME OF THE KEY CHANGES FROM THE 2022 L&R?**

4 A: First, Member load has declined due to Member exits and Partial Requirements.
5 Second, the capacity contribution from renewable resources has declined due to
6 the ELCC and PRM Study results (~~Attachment G-1 of the ERP Report (LKT-1)~~
7 Additionally, coal resource retirements occur during the RAP that result in firm
8 capacity reductions.

9 **Q: DOES THIS PHASE I ERP FILING SUPPLANT THE NEED FOR A 2023 ERP**
10 **ANNUAL PROGRESS REPORT?**

11 A: Yes. Tri-State has not filed ERP Annual Progress Reports (“APRs”) in the years
12 when a Phase I ERP is filed, given the comprehensive nature of a resource plan
13 filing.

14 **X. CONCLUSION**

15 **Q: WHAT PHASE I APPROVAL IS TRI-STATE REQUESTING IN THIS**
16 **PROCEEDING?**

17 A: Tri-State requests approval of the 2023 ERP and the accompanying assumptions
18 and studies, as reflected in the IRA Scenario, which is Tri-State’s preferred plan.
19 For the reasons established in the ERP Report (**LKT-1**) and attachments, as well
20 as in Tri-State’s Direct Testimony, the IRA Scenario is the most reliable, affordable,
21 and responsible path for Tri-State to reach both the goals of the State of Colorado
22 and those of our Members, system-wide.

23 **Q: WHAT PHASE II APPROVAL IS TRI-STATE REQUESTING IN THIS**

1 **PROCEEDING?**

2 A: Tri-State requests Commission approval of the proposed Phase II timeline, Phase
3 II RFPs, Bid Policy, IE SoW, Model PPAs and Term Sheets, Implementation
4 Report outline, 45-Day Report approach, and RAP Action Plan. Tri-State also
5 requests that the Commission approve its proposal to model no more than eight
6 Phase II portfolios²⁷ to be modeled, two of which will be identified through informal
7 discussions with stakeholders prior to the start of Phase II.

8 **Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

9 A: Yes.

²⁷ As identified in the ERP Report (**LKT-1**).

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

PROCEEDING NO. 23A-____E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION,
INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN

VERIFICATION

STATE OF COLORADO)
) ss:
COUNTY OF ADAMS)

I, Lisa K. Tiffin, being duly sworn, do hereby depose and state that I have read
the foregoing Direct Testimony, and the facts set forth therein are true and correct to the
best of my knowledge, information, and belief.

Subscribed and sworn to before me this 16th day of November 2023, at
Westminster, Colorado.

TRI-STATE GENERATION AND
TRANSMISSION ASSOCIATION, INC.

By: Lisa K. Tiffin
Lisa K. Tiffin
Senior Manager, Analytics & Forecasting

Witness my hand and official seal.

[Signature]
Notary Public

My Commission expires: 12/28/25.

Kimberly M. Strasburger
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20134072316
MY COMMISSION EXPIRES December 28, 2025

ATTACHMENTS

Attachment LKT-1	2023 Electric Resource Plan
Attachment LKT-2	Phase II Timeline
Attachment LKT-3	Phase II ERP Implementation Report Outline
Attachment LKT-4	Statement of Qualifications of Lisa K. Tiffin
Attachment LKT-5	Compliance Matrix
Attachment LKT-6	WAPA Compliance Matrix
Attachment LKT-7	Modeling Assumptions
Attachment LKT-7C	Modeling Assumptions
Attachment LKT-7HC	Modeling Assumptions
Attachment LKT-8	New Build Constraints
Attachment LKT-9	Transmission Constraints
Attachment LKT-10	Unique Scenario Assumptions
Attachment LKT-10HC	Unique Scenario Assumptions
Attachment LKT-11	Ancillary Services
Attachment LKT-12	Extreme Weather Event (EWE) Stress Assumptions
Attachment LKT-13	Tri-State System Topology
Attachment LKT-14	Resources Cover Page
Attachment LKT-15	Contracts and Power Purchase Agreements (PPAs)
Attachment LKT-15HC	Contracts and Power Purchase Agreements (PPAs)
Attachment LKT-16	Generic Resources Summary
Attachment LKT-16C	Generic Resources Summary
Attachment LKT-16HC	Generic Resources Summary
Attachment LKT-17	Existing Resources Summary
Attachment LKT-17C	Existing Resources Summary
Attachment LKT-17HC	Existing Resources Summary
Attachment LKT-18	Emissions Reduction Workbooks Cover Sheet
Attachment LKT-19	Business-As-Usual (BAU)
Attachment LKT-19HC	Business-As-Usual (BAU)
Attachment LKT-19HC	Business-As-Usual (BAU) - Executable
Attachment LKT-20	Inflation Reduction Act (IRA)
Attachment LKT-20HC	Inflation Reduction Act (IRA)
Attachment LKT-20HC	Inflation Reduction Act (IRA) - Executable
Attachment LKT-21	SPV 3 Early Retirement
Attachment LKT-21HC	SPV 3 Early Retirement
Attachment LKT-21HC	SPV 3 Early Retirement - Executable
Attachment LKT-22	Systems-Wide Emissions Reduction (System)
Attachment LKT-22HC	Systems-Wide Emissions Reduction (System)
Attachment LKT-22HC	Systems-Wide Emissions Reduction (System) - Executable
Attachment LKT-23	System-Wide Emissions Reduction (Colorado)
Attachment LKT-23HC	System-Wide Emissions Reduction (Colorado)
Attachment LKT-23HC	System-Wide Emissions Reduction (Colorado) - Executable

Attachment LKT-24	Aggressive Colorado Emissions Reduction
Attachment LKT-24HC	Aggressive Colorado Emissions Reduction
Attachment LKT-24HC	Aggressive Colorado Emissions Reduction - Executable
Attachment LKT-25	High Gas Sensitivity Analysis Results
Attachment LKT-26	Electric Energy and Demand Forecast
Attachment LKT-26C	Electric Energy and Demand Forecast
Attachment LKT-26HC	Electric Energy and Demand Forecast
Attachment LKT-27	Load Forecasts by State & Member
Attachment LKT-27HC	Load Forecasts by State & Member
Attachment LKT-28	Third Party Studies Cover Sheet
Attachment LKT-29	ELCC and PRM Study (Astrape)
Attachment LKT-29C	ELCC and PRM Study (Astrape)
Attachment LKT-30	Benchmarking Analysis (B&V)
Attachment LKT-30HC	Benchmarking Analysis (B&V)
Attachment LKT-31	Addendum to 2020 DSM Potential Study and BE Potential Study (Mesa Point Energy)
Attachment LKT-32	Reliability Evaluation
Attachment LKT-32HC	Reliability Evaluation

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)
Emergency Order: Craig Unit 1

)
)
)
)

Order No. 202-26-21

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit WW: NERC, Long-Term Reliability Assessment (Jan. 2026)

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Long-Term Reliability Assessment

January 2026



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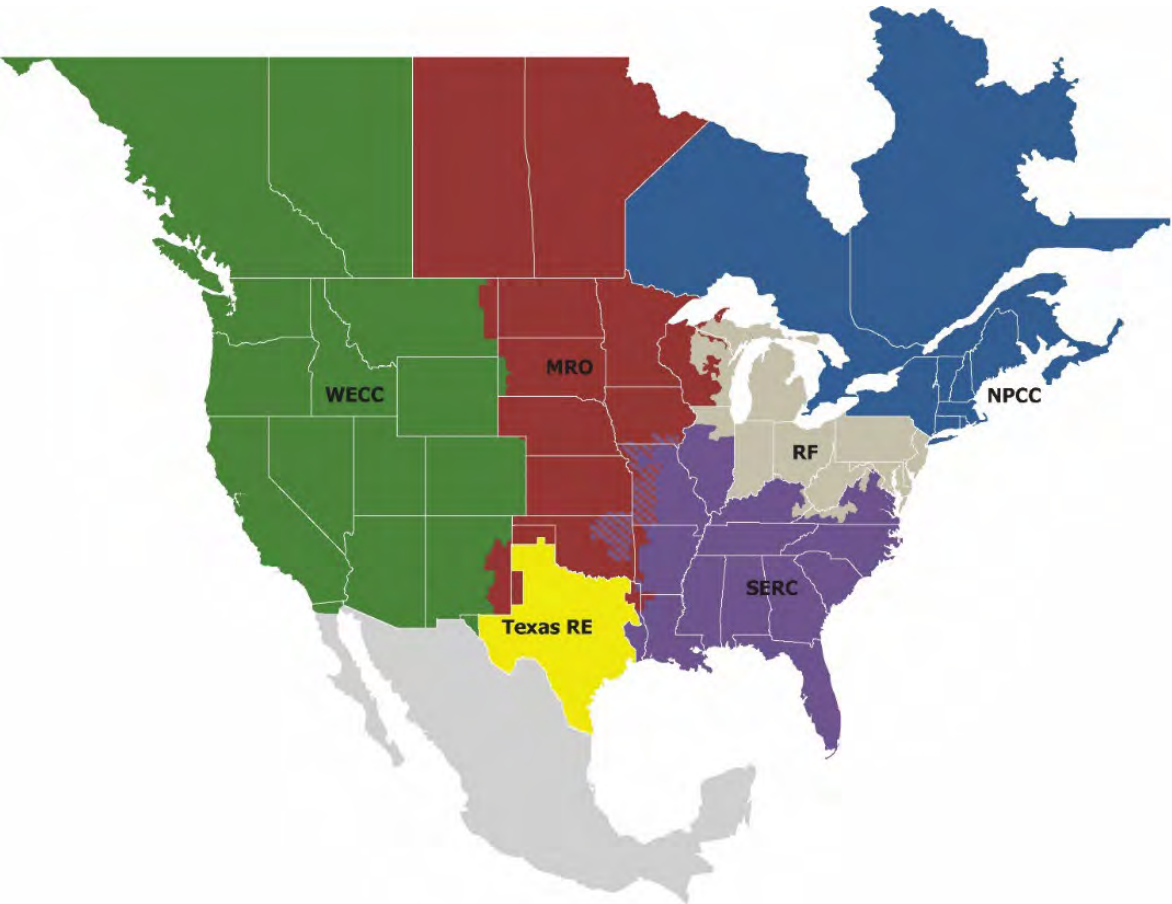
Preface

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

Reliability | Resilience | Security

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

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



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

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC’s regulations provides that “The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission.”

The *Long-Term Reliability Assessment* (LTRA), along with NERC’s other reliability assessments and analysis reports, supports the ERO Enterprise vision and mission by providing independent analysis of reliability risks. Other important assessments and reports include the following:

- **Seasonal Reliability Assessments:** The [Summer Reliability Assessment](#) (SRA) and [Winter Reliability Assessment](#) (WRA) provide overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected seasonal peak demands. They also identify reliability issues of interest and areas of concern for the upcoming season. Seasonal assessments are published annually prior to each respective season.
- **Special Reliability Assessments:** In addition to the long-term and seasonal reliability assessments, NERC also conducts [special reliability assessments](#) on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the NERC Board of Trustees or governmental authorities. Special reliability assessments are performed and published on an as-needed basis.
- **State of Reliability Report (SOR):** The [SOR](#) contains an unbiased, data-driven look at BPS reliability for the calendar year, identifying ongoing challenges and informing future-looking reliability assessments. It seeks to inform regulators, policymakers, and industry leaders of the most significant reliability risks facing the BPS and describe the actions that the ERO

Enterprise has taken, and will take, to address them. The SOR is published annually, containing analysis of BPS performance data from the prior year.

- **Event Analysis Reports:** NERC publishes reports of major system events and off-normal system occurrences as one output of the [ERO Event Analysis Program](#). This program employs rigorous post-event analysis and promotes broad understanding of the causes and effects of reliability events. NERC also publishes Lessons Learned for industry.

Reliability assessments and analysis are published on NERC’s [website](#).

Development Process

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

NERC develops the LTRA annually in accordance with the ERO’s Rules of Procedure¹ and Title 18, § 39.11² of the Code of Federal Regulations;³ this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.⁴

¹ NERC Rules of Procedure - Section 803

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

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

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

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.⁵ Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2025 about known system changes with updates incorporated prior to publication. This *2025 LTRA* assessment period includes projections for 2026–2035; however, some figures and tables examine data and information for the 2025 year. NERC’s standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the [Demand Assumptions and Resource Categories](#) section. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment, which is primarily focused on resource adequacy and operating reliability. NERC leads a multifaceted approach through its Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry and government partners.

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

Assumptions

In this *2025 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:⁶

- Supply and demand projections are based on industry forecasts that were submitted and validated in July 2025. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame has been included where appropriate.
- Peak demand is based on average peak weather conditions and forecasted economic activity at the time of submittal. Weather variability is discussed in each Regional Entity’s self-assessment.

⁵ [ERO Reliability Assessment Process Document](#)

⁶ Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year’s actual demand may deviate from the projection due to the inherent

- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, known planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading This Report

This report is compiled into two major parts:

- 1. A reliability assessment of the North American BPS with the following goals:**
 - a. Evaluate industry preparations that are in place to meet projections and maintain reliability, with a special focus on adequacy in the first five years
 - b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
 - c. Identify emerging reliability issues
 - d. Focus the industry, policymakers, and the general public’s attention on BPS reliability issues
 - e. Make recommendations based on an independent NERC reliability assessment process
- 2. A regional reliability assessment that contains the following:**
 - a. A 10-year data dashboard
 - b. Summary assessments for each assessment area
 - c. A focus on specific issues identified through industry data and emerging issues
 - d. A description of regional planning processes and methods used to ensure reliability

variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

The overall resource adequacy outlook for the North American BPS is worsening: In the 2025 LTRA, NERC finds that 13 of 23 assessment areas face resource adequacy challenges over the next 10 years. Projections for resource and transmission growth lag what is needed to support new data centers and other large loads that drive escalating demand forecasts. Most new resources in development to come on-line in the next five years consist of battery storage and solar photovoltaic (PV), which are inverter-based and weather-dependent resources that increase the complexity of planning and operating a reliable grid. Meanwhile, more fossil-fired generator retirements loom in the next five years, reducing the amount of generation that has fuel on site and impacting the system’s ability to respond to spikes in demand. The continuing shift in the resource mix toward weather-dependent resources and less fuel diversity increases risks of supply shortfalls during winter months. As Resource Planners, market operators, and regulators grapple with steep increases in demand and swelling resource queues, they face more uncertainty, adding to the already-complex endeavor of planning for resource adequacy during this period of rapid grid transformation. To ensure there are sufficient resources for supplying electricity in the future and to reliably meet the growing electricity needs for North Americans, industry, regulators, and policymakers need to be vigilant for shifting projections, keep plans for deactivating existing generators flexible, expedite system development, and perform robust adequacy assessments of future scenarios. In addition, careful planning and broad cross-sector coordination will be needed to navigate a period of potentially strained electricity resources.

The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The [Capacity and Energy Risk Assessment](#) section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions based on current BPS planning forecasts. NERC’s evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used a probabilistic assessment and a deterministic reserve margin analysis from the LTRA process to identify the risk of future electricity supply shortfall and determine a risk category for each assessment area based on consistent risk criteria.⁷ Risk assessment inputs are tied to industry forecasts of electricity supplies, demand, and transmission development, providing a forward-looking snapshot of resource adequacy.

⁷ In some cases, NERC modified the risk category when system studies performed by a system operator or regulator determine that resource adequacy target(s) will not be met. Details of the risk evaluation for each assessment area are in the [Capacity and Energy Risk Assessment](#).

Areas determined to be **High Risk** exceed the upper risk criteria levels. In high-risk areas, planned resources as of July 2025 would result in energy shortfalls that exceed resource adequacy targets or baseline criteria for unserved energy or loss of load.⁸ **Elevated-Risk** areas meet resource adequacy criteria, but planned resources are likely to result in energy shortfalls that are expected to be limited to more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, fuel supply disruptions, and limitations of normal electricity transfers. **Elevated-Risk** areas are identified in the LTRA when unserved energy and load loss metrics are below the **High-Risk** criteria but are not negligible. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions and are below the lowest risk criteria level. The results of the risk assessment are summarized for all elevated- and high-risk assessment areas in [Figure 1](#) and described in [Table 1](#).

⁸ The criteria used for risk determination in the LTRA include resource adequacy targets established by regulatory authorities, traditional 1-day-in-10 years load-loss criteria, and probabilistic loss-of-load-hour and expected unserved energy metrics. See [Risk Categories](#) in this report for a complete description.

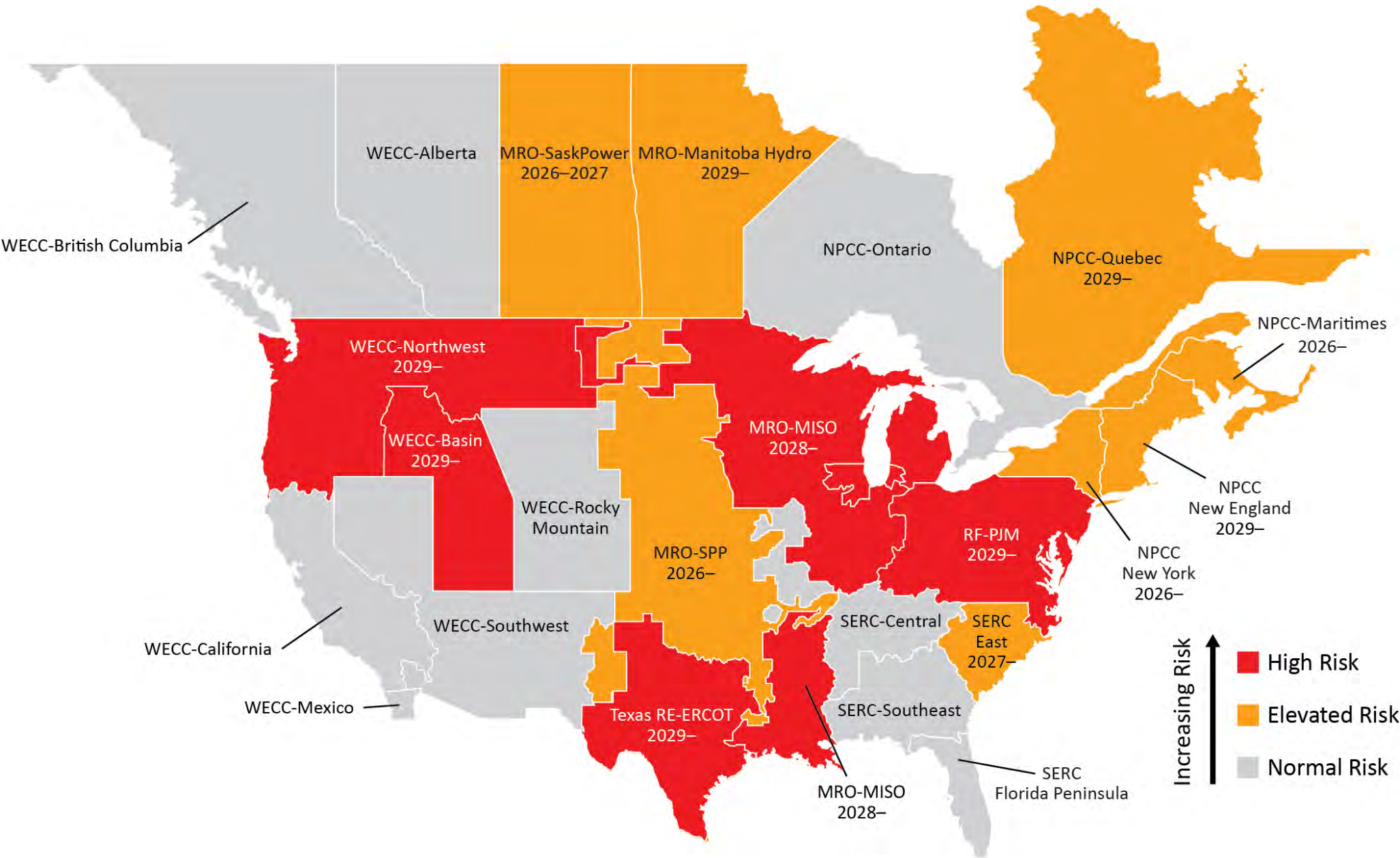


Figure 1: Risk Area Summary 2026–2030

Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

Table 1: Capacity and Energy Risk Assessment Area Summary

Assessment Area	Risk Level (High, Elevated, or Normal)					Risk Summary
	2026	2027	2028	2029	2030	
MISO						Projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements. The recently approved <i>Expedited Resource Addition Study</i> (ERAS) process is expected to result in additional resources in the MISO system beginning in 2028 that are not included in the model for the 2025 <i>LTRA</i> . Timely implementation of ERAS resources will eliminate reserve margin shortfall and improve expected unserved energy metrics.
MRO-Manitoba						With rising demand, planned reserves are falling, leading to potential resource shortfalls in low-hydro conditions.
MRO-SaskPower						With current resources, there is risk of insufficient generation during fall and spring when more generators are undergoing maintenance. Expected natural-gas-fired generator additions in Winter 2027 will boost planned reserves and reduce risks of unserved energy.
MRO-Southwest Power Pool (SPP)						Demand forecasts outpace resource additions, leading to falling reserve margins. Scenarios with low wind and high generator forced outages identify energy shortfall risks. SPP’s <i>Expedited Resource Adequacy Study</i> is attracting additional resources.
NPCC-Maritimes						Demand growth forecasts have increased since the 2024 <i>LTRA</i> , while expected capacity contributions from variable energy resources (VER) have declined, causing resource shortfalls in the near term. New natural-gas-fired generation planned for 2028 will reduce the potential unserved energy, but not below the elevated risk threshold.
NPCC-New England						Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of energy shortfalls in extreme winter conditions.
NPCC-New York						Planned retirements of peaking generators create localized system adequacy needs as described in the New York ISO 2025 <i>Q3 Star Report</i> .
NPCC-Québec						Demand growth projections are outpacing planned resource additions, leading to projected resource shortfalls in the winter season.
PJM						Current projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements. The anticipated resource margin falls below the Reference Margin Level starting in 2029. Recently approved new generation projects for expedited interconnection under the PJM Reliability Resource Initiative were not far enough along to include in the <i>LTRA</i> risk analysis.
SERC-East						Current projections for resource additions do not keep pace with escalating demand forecasts and planned generator retirements. With projected resources, supply shortfalls would occur in below-normal winter temperatures, resulting in unserved energy.
Texas RE-ERCOT						Probabilistic unserved energy metrics for 2026–2027 have improved since the 2024 <i>LTRA</i> , but continued rapid load growth outpaces projected resource additions in later years. To mitigate increasing resource adequacy risks from load growth, Texas lawmakers have granted ERCOT operators additional authority to curtail new large loads if necessary to prevent grid emergencies. Texas lawmakers also established funding programs to expedite new resources that address reliability needs.
WECC-Basin						Demand forecasts outpace resource additions and expected generator retirements, leading to falling reserves. Resource additions nearing completion are predominantly solar PV, leading to a more variable resource mix. Unserved energy risk is in summer.
WECC-Northwest						Rapid forecasted demand growth is driving the need for more resources. Resource additions nearing completion are predominantly solar PV, battery, and wind, leading to a more variable resource mix. Periods of unserved energy are projected for both summer and winter.

Regional Assessments Dashboards

The [Regional Assessments Dashboards](#) section contains dashboards and summaries for each of the 23 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Responding to Trends in Resource Adequacy

As resource adequacy concerns have expanded and grown more acute in many parts of the North American BPS, more actions have been taken by industry and regulators to bolster resources.

- Projected retirements have shrunk from the *2024 LTRA*. Growing demand, market signals, and resource plans have highlighted the potential need to keep resources on-line longer than previously anticipated. Though the confirmed and announced potential retirements over the next 10 years remain high and total over 105 GW in peak seasonal capacity, this is roughly 10 GW lower than the 10-year retirement projections last year.
- The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Market procurements are becoming more effective in procuring resources as a result.
- Expedited resource programs that were approved by FERC in late Summer 2025 for MISO, PJM, and SPP have resulted in acceleration and prioritization for resources that can address identified reliability risks. Most new resources brought in through recently approved expedited resource programs are not included in the *2025 LTRA* risk assessment.
- Lawmakers in Texas have provided ERCOT with curtailment management authority over new large loads to prevent grid emergencies and established funding to speed new generating capacity to the grid.

The [Capacity and Energy Risk Assessment](#) and [Regional Assessments Dashboards](#) sections provide details on these examples and initiatives in other assessment areas.

Trends and Reliability Implications

Demand, resource, and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the [Demand Trends and Implications](#) and [Transmission Development and Interregional Transfer Capability](#) sections.

Demand Trends and Implications

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year’s 10-year growth projection of 132 GW. Winter peak demand is expected to grow by 245 GW, continuing to outpace summer and exceed prior-year projections. New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.

Demand and large-load projections throughout the LTRA are based on load-serving entity (LSE) and BPS system planner forecasts provided to NERC during LTRA development, reflecting mid-2025 plans. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Still, large loads inherently add volatility to load forecasts as project timelines and commitments can vary with factors related to construction, permitting approvals, grid development, and data center owner decisions. ERCOT and PJM, the grid planners and operators for two areas experiencing vigorous large-load and data center development, have each prepared revised load forecasts since the *2025 LTRA* data collection period that, due to timing, is not used in this LTRA. Both forecasts indicate that some large-load projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Load forecasts that are revised downward can shrink the energy shortfalls that are projected in this LTRA.

Resource Additions and the Changing Resource Mix

The shift toward a more variable resource mix continues, as battery, solar PV, and hybrid generation lead the most recent and projected near-term additions and as fossil-fired generators retire. From 2024 to 2025, the existing capacity from fossil-fueled generators fell by 21 GW, while BPS capacity for peak demand hours from battery, wind, and solar resources increased by 23 GW.

In a shift from a key insight from the *2024 LTRA*, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and, together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year’s 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown modestly since

the 2024 LTRA by 7 GW (1.7%). This is slightly less than in the prior year when Tier 1 and Tier 2 capacity grew by 44 GW.

As older fossil-fired generators retire and are replaced by more battery and solar PV resources, the resource mix is becoming increasingly variable and weather-dependent. The share of VERs in the existing BPS on-peak resource capacity increased from 9.5% to 10.2% over the last year. VERs have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. Frequency response, or the ability of the BPS to maintain stable frequency, is one such ERS that NERC assesses on an Interconnection basis to ensure future resource mix reliability. Battery storage can enhance system frequency response. Other IBRs provide little or no frequency response capability, requiring grid operators to ensure that enough synchronous generators and other facilities are on-line for system stability. This year’s LTRA finds that the future resource mix in each Interconnection through 2027 has sufficient resource types to provide for adequate frequency response. As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

The thermal generation component of the resource mix is increasingly reliant on natural gas for fuel as new natural-gas-fired generators are added to the BPS and as some existing coal-fired generators undergo fuel conversion. Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years: 53 GW of new natural-gas-fired winter capacity is in the planning queues, and new ERAS programs will add more. As new natural-gas-fired generators progress through interconnection processes, Generator Owners, grid planners, and natural gas infrastructure developers need to take steps to ensure that regional natural gas infrastructure can reliably serve the needs of BPS generators.

Transmission Development and Interregional Transfer Capability

Transmission projections reported for the 2025 LTRA reflect an increase in transmission development, continuing a trend that emerged in the 2024 LTRA. This year’s cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years is substantially higher than the 2024 LTRA 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially over past-year levels; rather, the large increase in transmission projects is seen in planning phases. Several Planning Coordinators (PC) have recently approved, or are actively contemplating, expansive extra-high voltage (EHV) overlays on their systems to address new generator additions and a variety of reliability needs, including Hydro-

Québec, ERCOT, SPP, MISO, PJM, BC Hydro, and the Independent Electricity System Operator (IESO) in Ontario.

Interregional transmission projects that support energy transfers across Interconnections make up a small but important portion of total BPS transmission development. They can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,⁹ including scenarios identified in the *Interregional Transfer Capability Study* (ITCS) published by NERC in 2024, and the separate *Interregional Transfer Capability Study (Canadian Analysis)*. About 4% of transmission projects reported for the 2025 LTRA are for tie-lines that support transfers between neighboring systems, lower than the 6% reported in the 2024 LTRA.

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays. Other reasons for delays include economic impacts, planning and construction issues, permitting issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

- 1. **Integrated Resource Planners, market operators, and regulators: Expedite new resources to meet growing demand and carefully manage generator deactivations.** BPS planners should develop, implement, or enhance mechanisms to expedite resource additions to the grid that provide the services needed to address anticipated reliability issues related to each area’s needs. Independent System Operator/Regional Transmission Organizations (ISO/RTO) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulators must support resource development and manage the pace of retirements such that replacement infrastructure can be developed and placed in service to support reliability needs.
- 2. **NERC, industry, and regulators: Understand and manage reliability risks accompanying large-load growth and leverage potential capabilities in new types of loads to provide flexibility to operators during times of grid stress.** An increasing number of large commercial and industrial

⁹ [Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022 | Federal Energy Regulatory Commission](#)

loads is rapidly connecting to the BPS. Emerging large loads—such as data centers (including cryptocurrency and artificial intelligence applications) and hydrogen fuel plants—present unique challenges in BPS planning and operations. Stakeholders should support NERC’s Large Loads Action Plan¹⁰ and collaborate through NERC’s Large Loads Task Force.¹¹ ISO/RTOs should collectively work to create more uniform requirements to address the emerging reliability issues associated with large data center loads.

3. **NERC, Regional Entities, and industry: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year’s LTRA. To promote consistency in analysis and develop assessment capabilities, NERC and the Regional Entities piloted Interconnection-wide energy assessments using a common probabilistic resource adequacy tool in 2025. Wide-area energy analysis will support the evaluation of interregional transfer capabilities and the effects of extreme weather and regional fuel supply issues on the BPS at an Interconnection level. Industry should work with NERC through its technical groups to implement ERO energy assessments in the 2026 LTRA and continue to improve consistency in the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC’s LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy.
4. **Regulators and policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, many states are also taking steps to expedite siting and permitting. Siting and permitting issues are among the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.
5. **Regulators, electric industry, and gas industry member organizations: Continue identifying and implementing solutions for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** As various initiatives launched in past years roll out recommendations for addressing reliability needs, stakeholders should act with urgency on implementation. Continued collaboration through readiness forums and working groups remains a priority. While new regulatory and oversight mechanisms of the natural gas industry have yet to solidify, voluntary actions for managing natural gas production, processing, and delivery risks are needed. NERC, gas and electric industry, and research partners should continue studies and assessments of regional fuel supply risks to BPS generation.

6. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure that ERSs are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.¹² Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including VERs; however, policies and market mechanisms need to reflect these requirements to ensure that these services are provided and maintained. ISO/RTOs and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC’s LTRA and other assessment reports. All recommendations are listed in the [Recommendations and ERO Actions Summary](#).

¹⁰ NERC’s Large Loads Action Plan: <https://www.nerc.com/initiatives/large-loads-action-plan>

¹¹ NERC’s Large Loads Task Force webpage: [Large Loads Task Force \(LLTF\)](#)

¹² Essential Reliability Services:

<https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf>

Capacity and Energy Risk Assessment

Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure that sufficient resources are available to meet demand and prevent unacceptable levels of energy shortfall. In their application, traditional capacity-based adequacy criteria were not designed to consider the magnitude, frequency, duration, and timing of potential energy shortfalls. Such [considerations](#) have become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. NERC’s LTRA includes all-hours probabilistic indices to measure these additional dimensions of risk and provide a more complete analysis to inform system plans.

Assessment Approach

NERC evaluates industry-provided resource adequacy data and credible studies to assess risks of future energy shortfalls as the system is currently planned. Probabilistic and deterministic analyses provide forward-looking snapshots of resource adequacy tied to industry forecasts of electricity supplies, demand, and transmission development. The risk analysis entails these components:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high risk periods and potential energy constraints resulting in load-loss events. The 2025 ProbA is performed for each assessment area and examines the system as planned for the years 2027 and 2029. Loss-of-load hours (LOLH) and expected normalized unserved energy (NEUE) from NERC’s ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as the Reference Margin Level (RML)) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

NERC also incorporates other findings from scenarios or information from system studies to address assessment area-specific adequacy risks when needed. See MRO-SPP, NPCC-New England, and NPCC-New York.

The risk determination is based on data and information provided to NERC during LTRA development and represents a snapshot in time. Integrated resource planning and ISO/RTO resource adequacy mechanisms vary across North America and can be implemented to respond to resource adequacy issues on many different timescales.

The [Demand Assumptions and Resource Categories](#) section provides further details on these approaches. Assessment area dashboards (see [Regional Assessments Dashboards](#)) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

For the 2025 LTRA, NERC uses the following three levels of risk category determination for each assessment area and associated years for which there is a risk of energy shortfall during the first five years of the LTRA period (i.e., 2026–2030). The details for the risk criteria determination are shown below for each category of risk.

An assessment area is determined as **High Risk** when established resource adequacy targets or requirements are not met or when probabilistic or deterministic energy analyses find that planned resources produce shortfalls resulting in unserved energy or load loss exceeding criteria for baseline resource adequacy specified below. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See [Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area](#). Recently, regulators and policymakers in many states and market areas have begun to consider or develop resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.¹³ High risk areas are those where today’s demand forecasts and resource projections indicate a shortfall in future planned resources for expected (i.e., most likely, aka 50/50) demand and typical resource performance. More severe operating conditions associated with unusual heat waves or deep-freeze events would further exacerbate shortfalls in planned resources.



For the 2025 LTRA, NERC uses the following criteria to determine areas and associated years for which there is high risk of insufficient planned resources during the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA; or
- Annual normalized expected unserved energy (EUE) exceeds 0.002% (20 ppm) for one or more years in the ProbA; or

¹³ See the NERC-National Academy of Engineering Workshop Report [Evolving Planning Criteria for a Sustainable Power Grid](#).

- Resource adequacy target(s) established by regulatory authority or system operator are not met.

Resource Planners, regulators, and market operators in assessment areas identified as having a high risk of resource shortfalls can mitigate these risks through timely actions that address capacity and energy risks.

An assessment area is determined to have **Elevated Risk** when it meets the established resource adequacy targets and baseline criteria specified earlier but does not meet more stringent thresholds of unserved energy and load loss that provide for reliability in more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. For the *2025 LTRA*, assessment areas are classified as elevated risk when they meet any one of the following criteria in the first five years of the LTRA period (i.e., 2026–2030):



- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA
- Annual normalized EUE is less than 0.002% (20 ppm) but greater than or equal to 0.0002% (2 ppm) for one or more years in the ProbA
- Resource adequacy target(s) established by regulatory authority or system operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions indicate risk of loss of load

An assessment area is determined to have **Normal Risk** if resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas determined as normal risk are expected to have sufficient resources for plausible extreme¹⁴ conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2025 LTRA*,



assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is below 0.0002% (2 ppm).
- Resource adequacy target(s) established by regulatory authority or system operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from the ProbA performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In last year’s LTRA, NERC incorporated new probabilistic assessment risk criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report, [Evolving Planning Criteria for a Sustainable Power Grid](#), alongside established reserve margin criteria. In instances where an assessment area’s probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

A numerical summary of the assessment areas’ risk profile measured against the NERC risk criteria is summarized in **Table 2**. A risk description summary for each assessment area at an **Elevated Risk** or a **High Risk** is provided in the **High-Risk Area Details** or **Elevated-Risk Area Details** sections following **Table 2**. Full details about all assessment areas are provided in the **Regional Assessments Dashboards** section.

¹⁴ Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide-Area Heat Dome.

Table 2: Capacity and Energy Risk Assessment Numerical Summary

	NEUE (ppm)		LOLH (hours/year)		Anticipated Reserve Margin					Reference Margin Level ¹⁵				
Summer-Peaking Areas	2027	2029	2027	2029	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
MISO	1.13	42.39	0.23	6.61	11.0%	11.2%	9.5%	8.6%	4.3%	8.1%	8.3%	8.5%	8.5%	8.5%
MRO-SPP	0.00	0.00	0.00	0.00	32.4%	30.3%	28.4%	25.1%	22.6%	19.0%	19.0%	19.0%	19.0%	19.0%
NPCC-New England	0.00	0.02	0.00	0.00	18.3%	21.7%	24.8%	23.7%	23.6%	13.4%	13.0%	13.0%	13.0%	13.0%
NPCC-New York	0.00	0.08	0.00	0.03	22.3%	24.5%	24.5%	23.6%	22.5%	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Ontario	0.00	0.00	0.00	0.00	29.6%	19.8%	28.1%	18.7%	19.7%	16.1%	19.0%	22.6%	15.8%	19.5%
PJM	3.50	65.50	0.61	9.97	29.7%	28.3%	24.3%	18.9%	13.9%	18.6%	20.1%	21.9%	23.9%	26.3%
SERC-Central	0.00	0.00	0.00	0.00	19.1%	20.8%	19.7%	18.5%	16.5%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-East	0.98	2.27	0.15	0.33	30.6%	30.5%	30.5%	31.5%	34.9%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Florida Peninsula	0.00	0.00	0.00	0.00	27.4%	25.2%	24.3%	22.6%	21.1%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Southeast	0.00	0.00	0.00	0.00	35.9%	29.5%	29.8%	24.9%	20.9%	15.0%	15.0%	15.0%	15.0%	15.0%
Texas RE-ERCOT	8.70	18.84	0.95	3.64	28.2%	30.5%	31.8%	30.8%	29.9%	13.8%	13.8%	13.8%	13.8%	13.8%
WECC-Basin	0.04	2,250	3.00	310.00	36.3%	37.9%	27.4%	19.7%	15.2%	13.5%	14.0%	13.6%	12.4%	12.3%
WECC-California	0.00	0.00	0.00	0.00	53.2%	47.0%	46.1%	45.6%	42.7%	20.3%	19.2%	19.3%	19.7%	19.3%
WECC-Mexico	0.00	0.00	0.00	0.00	14.9%	13.8%	29.9%	27.0%	24.6%	7.8%	8.0%	9.1%	7.2%	7.0%
WECC-Rocky Mountain	0.00	0.00	0.00	0.00	51.3%	60.0%	53.2%	38.1%	30.5%	17.8%	17.0%	16.2%	16.1%	15.7%
WECC-Southwest	0.00	0.00	0.00	0.00	41.1%	39.6%	38.6%	38.4%	36.1%	13.3%	13.7%	13.6%	12.6%	12.2%
Winter-Peaking Areas	2027	2029	2027	2029	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
MRO-Manitoba Hydro	0.12	0.23	0.03	0.06	13.9%	16.7%	15.4%	13.6%	1.2%	12.0%	12.0%	12.0%	12.0%	12.0%
MRO-SaskPower	5.24	0.19	1.09	0.05	25.9%	35.0%	33.4%	32.3%	31.2%	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Maritimes	0.52	0.25	0.25	0.10	17.2%	18.5%	25.6%	23.0%	21.7%	20.0%	20.0%	20.0%	20.0%	20.0%
NPCC-Québec	0.00	0.29	0.00	0.11	15.6%	16.7%	14.7%	13.0%	11.5%	11.9%	12.2%	12.2%	12.2%	12.2%
WECC-Alberta	0.00	0.00	0.00	0.00	36.2%	45.3%	40.7%	38.0%	33.0%	11.8%	17.6%	14.3%	15.6%	11.6%
WECC-British Columbia	0.00	0.00	0.00	0.00	23.4%	19.1%	19.5%	24.1%	24.2%	11.7%	12.1%	12.1%	11.6%	11.6%
WECC-Northwest	0.00	36.64	0.00	85.00	30.2%	29.3%	23.3%	19.1%	15.7%	17.8%	17.4%	16.1%	15.8%	15.5%

¹⁵ Refer to the [Regional Assessments Dashboards](#) and the [Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area](#) table.

High-Risk Area Details

The assessment areas below exceed the highest level of risk criteria for the **High-Risk** classification during one or more years of the 2026–2030 period. Areas are listed in order of appearance in the [Regional Assessments Dashboards](#) section.

MISO (Normal Risk 2026/ Elevated Risk 2027/ High Risk 2028–)

Escalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area. MISO forecasts its peak total internal demand at 127 GW during the 2026 summer season (up over 2.6 GW since the same year’s projection in the 2024 LTRA) and expects that summer demand will grow to 143.7 GW by 2035. The largest contributor to this accelerated demand growth is data center additions with 18 GW of data center loads projected by 2035. MISO’s accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements. New solar PV resources contribute to a 5.7 GW increase in MISO’s accredited non-thermal capacity since last year.

As of July 2025, MISO has more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity. In addition to these resources, MISO instituted the [ERAS](#) process to respond to generation needs. The ERAS process provides a framework for the accelerated study of generation projects that address urgent resource adequacy and reliability needs in the near term. ERAS projects are not in the model for the 2025 LTRA. If ERAS projects come in as currently planned, the projected reserve margin shortfall would be eliminated.

Based on the current resource and demand forecasts, MISO begins to meet elevated-risk criteria in 2027 (see [Table 3](#)). While resources are adequate for regulatory requirements, the ProbA results show load loss and unserved energy exceeding the elevated-risk threshold. The Summer season makes up the bulk of annual risk in this region and is seen to materialize during late afternoon and evening hours when demand is high and solar resource output begins to decline. The ProbA also identifies winter risk periods during early morning and hours after 7:00 p.m. Additionally, shortfall risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high.

As the demand forecast rises in subsequent years, and with currently projected generator retirements and planned resource additions, the ProbA shows worsening results. While resources are adequate for regulatory requirements (i.e., loss of load expectation (LOLE) of 0.1 day in a year), the ProbA results show load loss and unserved energy exceeding the elevated risk threshold criteria.

For the 2029 ProbA study, MISO assumed 14 GW of generator retirements that are uncertain to occur by 2029.

Table 3: MISO Base-Case Summary of Results		
	2027	2029
EUE (MWh)	797	31,654
NEUE (ppm)	1.13	42.39
LOLH (hours per Year)	0.23	6.61
Category	Elevated	High

With model assumptions, MISO would exceed load-loss and unserved energy criteria and fall below reserve margin targets to become a high-risk area beginning in Winter 2028 (see [Figure 2](#)). Projections for resource additions are predominantly solar PV, with some battery and wind resources. The small amounts of natural-gas-fired generation in signed interconnection agreements do not offset planned generator retirements, and, as a result, MISO is projecting shortfalls in planned resources for winter peak periods.

These results offer a point-in-time snapshot of risk based on the data available during the time of this year’s analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and can work to address uncertainties associated with these three phenomena.

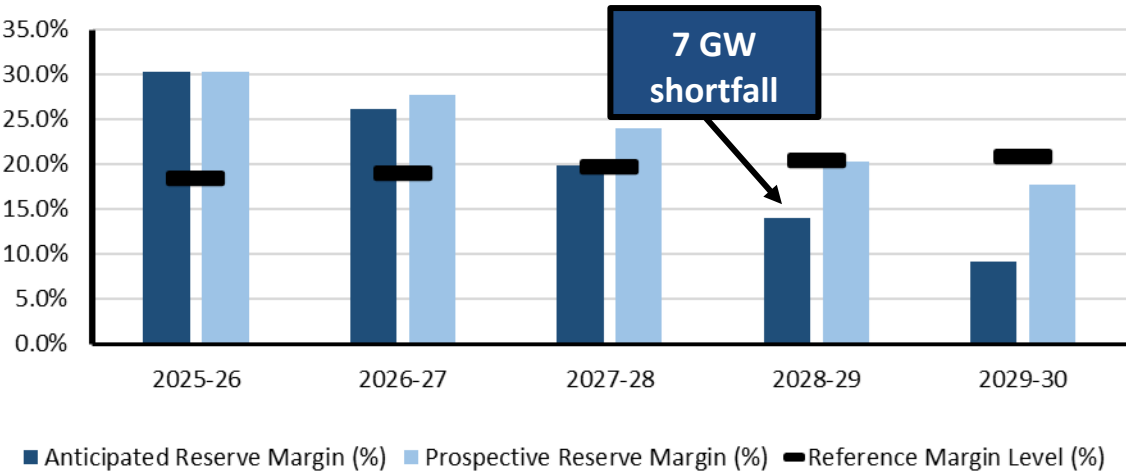
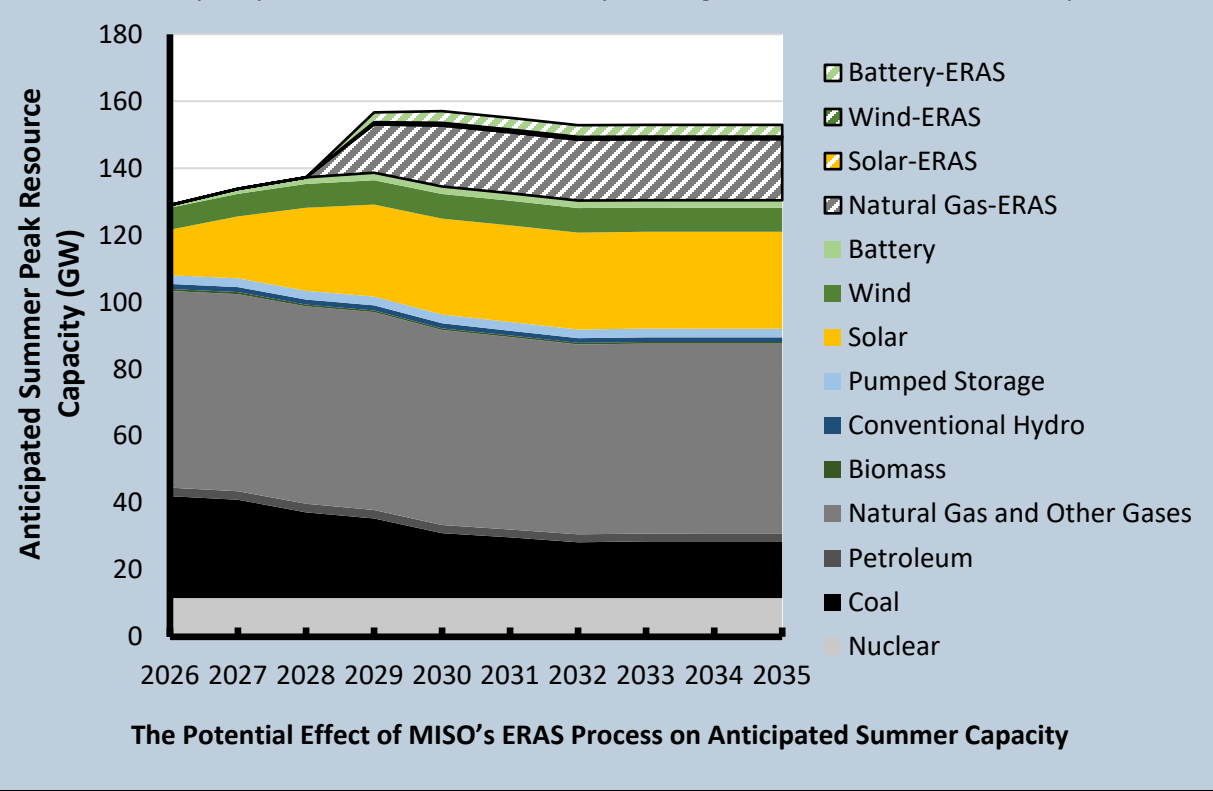


Figure 2: MISO Winter Planning Reserve Margins

Currently, MISO has surplus transfer capacity within its assessment area, but transfers between subregions have been historically constrained by a transmission limitation between the northern and southern MISO subregions.

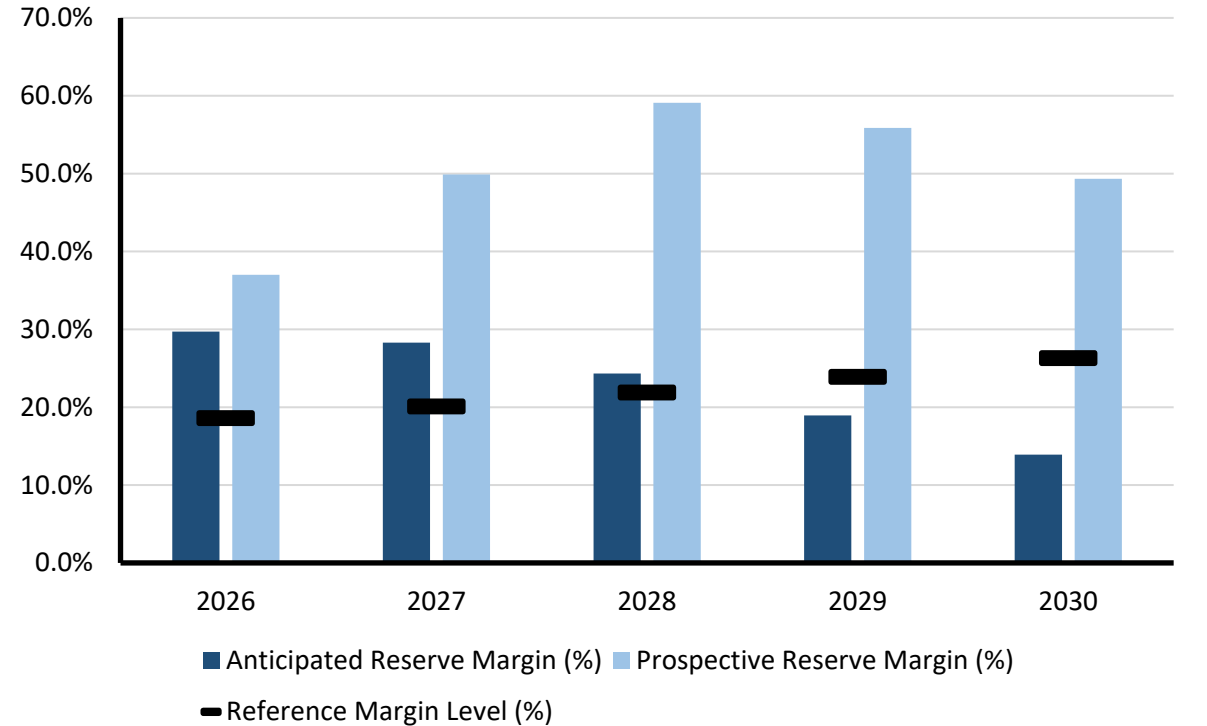
The timing of FERC’s approval of MISO’s ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the 2025 LTRA. ERAS is already expected to result in considerable new resource additions to the MISO system in the near term. The additional summer on-peak capacity from ERAS is expected to grow to over 20 GW by summer 2030. These expedited resource additions are expected to reduce the shortfall risk identified in this year’s ProBA. Furthermore, the timing of the ERAS additions would mitigate an identified winter ARM shortfall if the approximately 8.6 GW of winter on-peak capacity anticipated by 2028–29 reaches operation as projected. The latest ERAS projects, along with current load forecasts and resource projections as of July 2026, will be included in the input data for the 2026 LTRA, and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.



PJM (Elevated Risk 2026–2028/ High Risk 2029–)

Demand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads. PJM expects its summer peak demand to grow by 56 GW to a total of 210 GW in 2035, and its winter peak demand is expected to climb by 62 GW to reach 198 GW by winter 2034–35. PJM’s annual net energy for load growth rate is projected to average 4.8% per year over the next 10 years, up from 2.3% in last year’s projections.

At the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays. A large share of PJM’s new interconnection requests is from VERs, approximately 40% of which are solar, and dispatchable resources are currently leaving the system faster than they can be replaced with other dispatchable technologies. These factors, paired with PJM’s limited reliance on transfers from neighboring areas to meet resource adequacy targets (maximum total transmission interchange capability is <2% of PJM’s internal generation capacity), have led to a projection that PJM’s ARM may fall below its Installed Reserve Requirement (or RML) in 2029 (see [Figure 3](#)).



As part of its reforms to speed interconnection with the system, PJM has approximately 30,000 MW of generation projections in the transitional interconnection queue to be processed in 2026. PJM’s new cycle process opens in April with a one- to two-year timeline for reviews, depending on the impact to the system. From the time of the original 2025 LTRA data submittal to recent evaluation, PJM projected an additional 8.3 GW of Tier 1 summer resource capacity over the next seven years. Tier 1 resource additions will provide 3.4 GW of winter capacity. However, many of these projects continue to be slowed or stopped by factors affecting multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges or financing.

In 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative (RRI), which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original 2025 LTRA data submittal and 4.1 GW in winter capacity. This net increase factors resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

Setting aside the impact of such initiatives, results of the ProbA using PJM’s current resource and demand forecasts indicate that the area is at an elevated risk of resource shortfalls at the beginning of the 10-year horizon (see [Table 4](#)). Because this year’s ProbA does not study years earlier than 2027, the elevated-risk determination is based on results of the 2024 ProbA and consideration of the declining ARM in PJM since last year’s LTRA (2026 Summer ARM has fallen from 35.7% to 29.7%). The greatest risk of resource shortfalls leading to unserved energy or load loss in PJM occurs in the winter months during the early morning and evening hours. The risk is associated with generator availability and performance issues that can arise from equipment freezing and fuel supply issues during extreme winter conditions. PJM falls into the high-risk category beginning in 2029 as demand forecasts continue to climb, generators reach planned retirement dates, and the projected resources become less certain. The winter risk profile indicates that new resources will need to be capable of reliably serving winter load.

Table 4: PJM Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	538	3,251	67,581
NEUE (ppm)	0.00	3.50	65.50
LOLH (hours per Year)	0.1	0.61	9.97
Category	Elevated	Elevated	High
*Provides the 2024 ProbA Results for Comparison			

Texas RE-ERCOT (Elevated Risk 2026–2028/ High Risk 2029–)

The Texas RE-ERCOT assessment area is forecast to experience continued rapid electric demand growth over the next 5–7 years. ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads totaling 45 GW by 2030, of which 23 GW are data centers.

ERCOT continues to evolve its planning methods as fluctuations in recent large interconnections activity continue to affect both near- and long-term demand expectations. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Such fluctuations do not, however, undercut the significance of demand growth attributable to large loads.

Responding to rapidly escalating demand from data centers and other large industrial loads, ERCOT, regulators, and lawmakers in Texas are adapting with policy and planning approaches to address emerging supply risks. Actions provide ERCOT with new curtailment management tools for large loads, establish criteria for when to incorporate new large loads in system planning, and help fund and speed new generating capacity to the grid. Furthermore, the first reliability assessment for the Public Utility Commission of Texas (PUCT)-approved Reliability Standard, and potential approval of market design changes to address deficiencies, is scheduled for completion by year-end 2026. Such market design changes would further mitigate energy risk.

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and provide ERCOT authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. For the 2025 LTRA, ERCOT’s DR contributions have increased substantially to reflect the authority and capability to curtail new large loads during energy emergencies. For Summer 2026, DR contributes 13.3 GW to resource adequacy (up from the 2.7 GW projection in the 2024 LTRA), and contributions from DR rise to 53.1 GW by 2030. Because new large loads can be curtailed during energy emergencies, the rapid rise in projected large loads has substantially less effect on Planning Reserve Margins in ERCOT than in the 2024 LTRA.

The ARM is above the 13.75% RML for all years (see [Figure 4](#)).

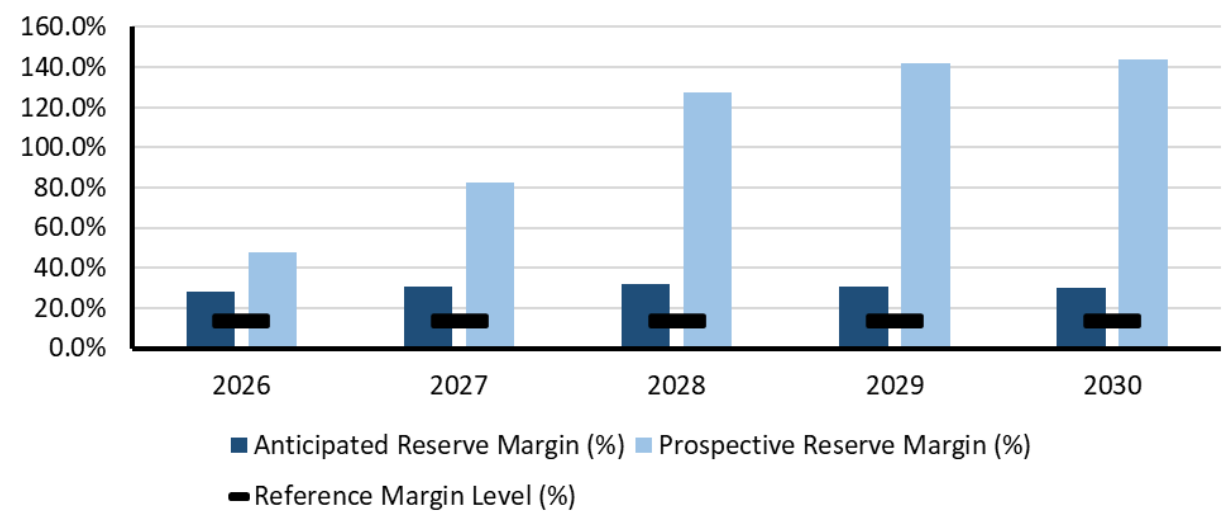


Figure 4: TEXAS RE-ERCOT Summer Planning Reserve Margins

ERCOT’s Planning Reserve Margins in the 2025 LTRA are also being affected by the implementation of new capacity contribution methods. ERCOT has switched from using historical average on-peak capacity factors to average effective load carrying capabilities (ELCC) for VERs, and the resulting capacity derates largely offset the gains that load management programs have on ARM. In the case of solar, ELCCs are significantly lower than prior years. ELCC values are probabilistically derived and reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low.

The ProbA results for Texas RE-ERCOT reveal some improvement in near-term resource adequacy when compared to the 2024 LTRA, but the area remains an elevated risk through 2027 before forecasted load growth drives the area to high risk (see Table 5). ERCOT’s ProbA modeling includes demand-side management protocols that reasonably reflect large load curtailments described above, and other programs used in ERCOT’s market. This modeling contributes to the improved unserved energy and load-loss hour metrics that are observed between the 2024 ProbA and the current ProbA. Battery resource additions since last year and improved modeling in the resource adequacy analysis tool also contribute to these improved metrics.

Table 5: Texas RE-ERCOT Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	11,090	5,865	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.95	3.64
Category	Elevated	Elevated	High
*Provides the 2024 ProbA Results for Comparison			

ERCOT’s ProbA study results show that most resource adequacy risk is in the winter, and this is mainly driven by the large demand variability associated with winter temperatures. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year. For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours (peaking at hour ending (HE) 9:00 p.m.) based on probabilistic capacity reserve modeling for monthly peak load days. During these periods, the drop-off in solar generation causes margins to decrease when load remains high. Battery storage helps reduce these short-duration energy risks. ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026 (Existing and Tier 1 resource categories) and grow to 25.2 GW by 2029. ERCOT typically sees the greatest energy provided by energy storage during net load peaks when solar is ramping off in the evening, or during early morning hours prior to solar ramping up.

In response to the rapid and unprecedented load growth, the PUCT in April 2025 approved three 765 kV import paths identified in the *Permian Basin Reliability Study*, which introduced the new 765 kV voltage class into the ERCOT region after six decades since the introduction of the 345 kV voltage class. The Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP) tackles the unprecedented load growth expected by 2030 and enhances transfer capability by an additional 600 MW to 3,000 MW. This 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers.

WECC-Basin (Elevated Risk 2026–2028/High Risk 2029–)

Forecasted load growth and planned generator retirements in the Great Basin (WECC-Basin assessment area) present resource adequacy challenges. Over the next 10 years, the summer demand forecast will rise by over 1.7 GW (17%, or 1.8% compounded annually), while at the same time the capacity from currently existing resources will decline by nearly 2.3 GW through generator retirements and other capacity changes. Solar resources are the predominant type nearing project completion: There is 3.5 GW of nameplate solar capacity (capable of providing 2.3 GW to summer capacity) in Tier 1 resources for the assessment period, making up nearly half of all resources in the

Tier 1 and Tier 2 planning.¹⁶ The projected resources, with planned retirements and additions, are not sufficient for forecasted demand, resulting in some unserved energy and load-loss hours in the future-year energy analysis. While the ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH (see [Table 6](#)).

Table 6: WECC Basin Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2,250.70
LOLH (hours per Year)	N/A	3.00	310.00
Category	-	High	High
*No prior results as the assessment area is new for the 2025 LTRA.			

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. ProbA results for 2027 indicate that risk is most concentrated to the month of peak demand and the hours around sunset as solar output declines. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime. In WECC’s ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in unserved energy and load-loss hours.

Unlike the ProbA results from other areas, WECC’s probabilistic model produces values higher values for load loss and EUE because the results are not probabilistic weighted averages. Taking this into account, NERC assesses WECC Basin as an elevated risk through 2029 even though the reported load-loss hours from the simulations exceed high-risk criteria

WECC-Northwest (Normal Risk 2026–2028/ High Risk 2029–)

Peak load in the WECC-Northwest assessment area is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest. There are over 10 GW of new wind, solar, and battery projects expected to connect over the next five years (nameplate capacity) and provide an expected on-peak capacity contribution in winter of 3.2 GW. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from

¹⁶ Tier 1 resources in the LTRA are those resources in the interconnection process that have high confidence of being realized and generally under construction or have signed interconnection agreements. Tier 2 resources have more uncertainty in being realized and are in earlier development stages such as undergoing interconnection planning study.

emerging. While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029 (see [Table 7](#)).

Table 7: WECC Northwest Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	8,080
NEUE (ppm)	N/A	0.00	36.64
LOLH (hours per Year)	N/A	0.00	85.00
Category	N/A	Normal	High
* No prior results as the assessment area is new for the 2025 LTRA.			

Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer.

Elevated-Risk Area Details

The below areas are classified as **Elevated Risk** as they are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the [Regional Assessments Dashboards](#) section.

MRO-Manitoba Hydro (Normal 2026–2028/ Elevated 2029–)

The Winter 2026–2027 peak demand forecast grew by 127 MW, exceeding the projected 29 MW growth from the 2024 LTRA. Demand growth is driven primarily by population growth and expected economic activity. Conversely, the forecasted annual peak demand growth rate for the next 10 years has fallen to almost 1.4%, down from around 1.8% projected in the 2024 LTRA. Generating resources are projected to remain largely the same over the 10-year planning period.

Similar to prior probabilistic assessments, Manitoba Hydro’s 2025 ProbA indicates elevated-risk levels of load loss in the later (year 4) study year (see [Table 8](#)). Resource adequacy concerns and load-loss risk in the ProbA arise from studied very low hydro conditions. Although the Manitoba system is

winter-peaking, the risk is primarily present during the summer season, with some risk also identified in the spring shoulder season. Planned electricity supply resources could fall short during an extreme and prolonged drought, affecting the predominantly hydroelectric system.

Table 8: MRO-Manitoba ProbA Summary of Results			
	2026*	2027	2029
EUE (MWh)	5	3	6
NEUE (ppm)	0.18	0.12	0.23
LOLH (hours per Year)	0.06	0.03	0.06
Category	Normal	Normal	Elevated
* Provides the 2024 ProbA Results for Comparison			

MRO-SaskPower (Elevated 2026–2027/ Normal 2028–)

Large industrial loads in Saskatchewan are driving average annual peak demand growth of 1.0% compounded annually over the next 10 years, down slightly from the 2024 LTRA’s projection (1.35%). To respond to demand growth, SaskPower recently added 370 MW of natural-gas-fired generation, 220 MW of VERs, and a 20 MW/20 MWh battery storage system to its system and is projecting on-peak resource additions of 700 MW over the next 10 years—a slight decrease from last year’s projection (~1 GW). Nameplate additions include 400 MW of wind, 300 MW of solar, and 525 MW of natural gas to offset ~32 MW of confirmed waste heat recovery and wind generation retirements. Saskatchewan is also deferring generator retirements and reactivating recently deactivated coal units and is bolstering both its intra-regional and interregional transmission system to diversify its current portfolio that relies heavily on firm transfers with Manitoba. Reserve margins are expected to remain above SaskPower’s RML for the entire 10-year period of the 2025 LTRA.

SaskPower is a winter-peaking system, but MRO-Saskatchewan’s probabilistic studies concluded that LOLH and EUE could occur during planned outages of large generators during peak demand hours in the spring and fall seasons. The ProbA reveals load-loss risk during the months of May, August, September, and October in 2027 based on current planned resources and load forecasts. Monthly and annual results improve in 2029 with SaskPower’s projected resource additions (see Table 9).

Table 9: MRO-SaskPower Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	76	145	5
NEUE (ppm)	2.81	5.24	0.19
LOLH (hours per Year)	0.55	1.09	0.05
	Elevated	Elevated	Normal
*Provides the 2024 ProbA Results for Comparison			

MRO-SPP (Elevated 2026–)

Resource additions and delays in generator retirements since the 2024 LTRA are improving the resource adequacy outlook for 2026, while higher demand forecasts and less capacity projects in development are causing lower planned reserves in later years. SPP’s ARMs are projected to remain above RMLs until after 2030 (see Figure 5). Additionally, ProbA results of the planned resources and demand forecast did not identify EUE or load-loss hours in studied years. Seasonal resource adequacy assessments by NERC have identified risks of insufficient operating reserves during periods of low wind and high generator outages.¹⁷ SPP is an elevated risk because it is projected to have lower planned reserves with a similar mix of VERs and dispatchable thermal generation in the future.

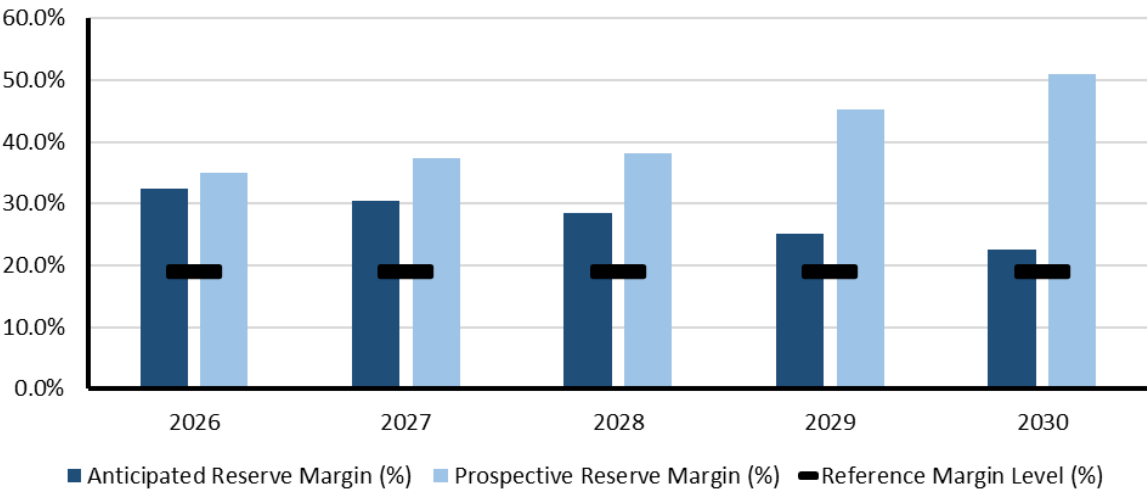


Figure 5: MRO-SPP Five-Year Planning Reserve Margin—Summer

¹⁷ See [NERC 2025 Summer Reliability Assessment](#)

Recent and newly approved resource adequacy initiatives in SPP are aimed at addressing demand growth and energy challenges associated with the evolving resource mix. SPP has approved higher Planning Reserve Margin requirements for LSEs that take effect beginning in the summer of 2026, along with a new winter reserve margin requirement starting later that year. These reserve margin requirements respond to growing resource adequacy challenges by obligating LSEs to obtain more firm resources for the summer and winter seasons. New performance-based resource accreditation will more accurately account for generator contributions to serving area demand during times of greatest need. The *Expedited Resource Adequacy Study* process, approved by FERC in July, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs.

NPCC-Maritimes (Elevated 2026–)

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period (see [Table 10](#)). This translates to compound average growth rates of 0.8% in summer and 1% in winter, which are higher than the *2024 LTRA* projections (0.4% in summer and 0.6% in winter). Resource projections for Maritimes have diminished slightly since the *2024 LTRA* due to smaller peak capacity contributions from certain VERs through most of the planning period.

Firm capacity transfers in the first two years of the assessment period (2026–2027 and 2027–2028) decreased significantly from the *2024 LTRA* (322 MWs to -32MWs in 2026 and 215 MWs to 75 MWs in 2027). As a result, the ARM is below the 20% RML in those years, 17.2% and 18.5%, respectively. Beginning in 2028, the capacity transfers for the remaining assessment period are consistent with those in the *2024 LTRA*, and ARMs are projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

Table 10: NPCC-Maritimes Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	5	15	7
EUE (ppm)	0.17	0.52	0.25
LOLH (hours per Year)	0.09	0.25	0.10
*Results from the 2024 The ProbA simulations			

The ProbA for 2027 indicates elevated levels of unserved energy in the peak winter month of February. Load growth projections and resource mix characteristics are the primary driver. A few hours of risk occur in other winter months. Resource additions contribute to the improved EUE and LOLH metrics for the 2029 study year.

NPCC-New England (Normal 2026 –2028/ Elevated 2029–)

Since the *2024 LTRA*, 650 MW of fossil-fired generation has retired in New England, while wind, battery, and solar projects and uprating to an oil-fired power plant are projected to increase summer capacity by 1 GW in Summer 2026. Winter capacity is also increasing by a similar amount due to the expected contribution of offshore wind by winter 2026–2027. New England is among the areas projecting the highest growth in winter electricity demand, with winter peak demand forecast to increase by 7.1 GW (36%) from the Winter 2025–2026 forecast over the next 10 years. This demand forecast has changed little since the *2024 LTRA*.

ProbA results and reserve margin assessment for the NPCC-New England Assessment Area indicate that the risk of unserved energy in New England is small (see [Table 11](#)). Unserved energy risk is concentrated in the summer months when area demand currently peaks. However, escalating winter electricity demand and the performance challenges faced by the current and future resource mix in extreme, long-duration cold weather events is a persistent reliability concern. New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. Interstate natural gas pipelines serving New England run at full capacity with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. An extended cold spell or a series of cold spells can threaten regional natural gas fuel delivery infrastructure and result in insufficient fuel for electric generators. Dual-fueled generation provides crucial alternative energy to maintain electric system reliability. In scenarios of extended extreme cold, stored liquid fuels can become depleted and result in insufficient generation for demand.

Table 11: NPCC New England Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	11	<1	2
NEUE (ppm)	0.10	0.00	0.02
LOLH (hours per Year)	0.10	0.00	0.00
Category	Normal	Normal	Normal
* Provides the 2024 ProbA results for Comparison			

NPCC-New York (Elevated 2026–)

The *LTRA* anticipated and Prospective Reserve Margins are above RML of 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the demand forecast with a greater risk added due to the variability in resource contribution. Demand could be 10–13% higher than expected, which could cause strain on the system.

This impact is shown in the increasing LOLH and EUE shown in [Table 12](#).

Table 12: NPCC New York Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	2	<1	12
NEUE (ppm)	0.01	0.00	0.08
LOLH (hours per Year)	0.01	0.00	0.03
Category	Normal	Normal	Normal
* Provides the 2024 ProbA results for Comparison			

While NPCC’s ProbA results and reserve margin assessment for the New York assessment area indicate that the risk of unserved energy in New York is relatively small, an assessment performed by NYISO, the *2025 Quarter 3 Short-Term Assessment of Reliability (STAR)*,¹⁸ identified transmission security reliability needs in the New York City and Long Island parts of the system to ensure summer reliability. With little reliability margin, plausible futures point to system issues within the next 10 years. Depending on demand growth and retirement patterns, the system may need several thousand megawatts of new dispatchable generation over that time frame.

Due to the reliability needs identified in the STAR report, NERC assesses that NPCC-New York is an elevated risk area and that, with current resource and transmission system projections, localized supply shortfalls are likely in extreme conditions.

NPCC-Québec (Normal 2026–2028/ Elevated 2029–)

Québec’s demand forecast has increased since the 2024 LTRA, driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data centers are also contributing to demand growth. Québec’s demand peaks at 41.4 GW in 2026–2027, rising to 49.6 GWs by 2035–2036, an increase of 8.2 GWs compared to the assessment period growth of 7.5 GWs projected in the 2024 LTRA.

With stable resources over the 10-year assessment period, Québec’s ARMs remain above the 12.2% RML for the first four years, falling below in 2030–2031 and all subsequent years. Québec and Ontario have a firm seasonal capacity exchange agreement through 2030–2031 that allows Québec to import 600 MW in winter.

¹⁸ Additional details available in the report: <https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf/>

Hydro-Québec’s Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and natural-gas-fired generation. These resources are not included in the present assessment due to their early development stage but are expected to be incorporated gradually into future assessments.

Hydro Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, EUE and LOLH are above the elevated risk criteria See [Table 13](#).

Table 13: NPCC Québec Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	8	8	63
NEUE (ppm)	0.04	0.00	0.29
LOLH (hours per Year)	0.01	0.00	0.11
Category	Normal	Normal	Elevated
* Provides the 2024 ProbA results for Comparison			

SERC-East (Normal 2026/ Elevated 2027–)

SERC-East is projecting over 5.7 GW of coal unit retirements over the 10-year assessment horizon. These continued retirements from prior years continue to trigger reserve margin targets and ProbA thresholds for elevated risk. To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years. The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years, as shown in [Table 14](#) below.

Table 14: SERC-East ProbA Summary of Results			
	2026*	2027	2029
EUE (MWh)	143	232	539
NEUE (ppm)	0.60	0.98	2.27
LOLH (hours per Year)	0.09	0.15	0.33
Category	Normal	Elevated	Elevated
* Provides the 2024 ProbA Results for Comparison			

Normal-Risk Area Details

All other assessment areas (see [Figure 1](#)) are classified as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

Resource and Demand Projections

The [Capacity and Energy Risk Assessment](#) section is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the 2025 LTRA assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that the risk assessment map will expand with more elevated- and high risk areas in the future.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, petroleum, and nuclear generators can negatively affect the resource adequacy and reliability of the BPS in the next 10 years. In the preceding [Capacity and Energy Risk Assessment](#), NERC accounted for nearly 92GW of nameplate of fossil-fired and nuclear generator retirements that are anticipated through 2035. NERC’s risk analysis did not include an additional 65 GW of nameplate fossil-fired generators that have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. Combined, the confirmed and announced-potential retirements over the next 10 years total over 105 GW in peak seasonal capacity, roughly 10 GW lower than the 10-year retirement projections in the 2024 LTRA (see [Figure 6](#)). Projected retirements overall, both confirmed and unconfirmed, have shrunk from the prior year’s LTRA as reliability needs have expanded with the continued growth in anticipated large-load interconnections. The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Growing demand and evolving planning methodologies have highlighted the potential need to keep resources, particularly non-variable resources, on-line longer than previously anticipated.

¹⁹ Confirmed generator retirements are reported to NERC by each assessment area in this 2025 LTRA development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each

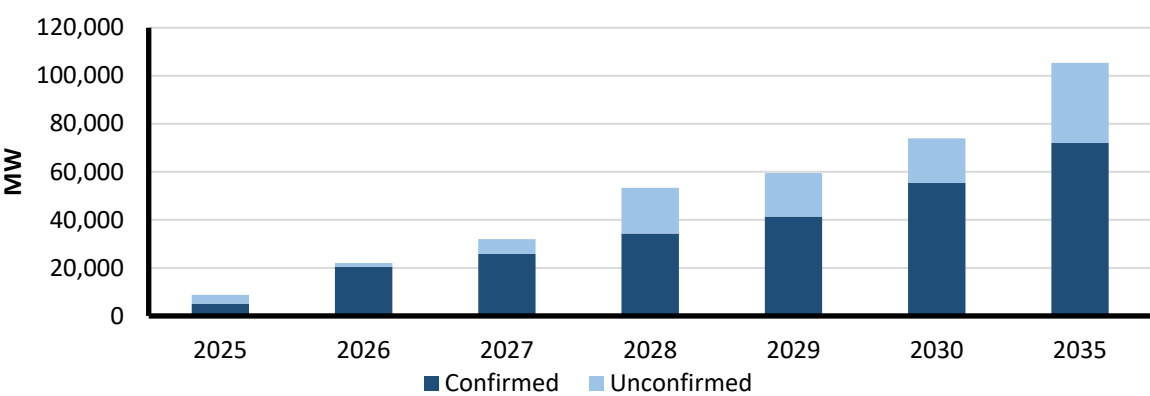


Figure 6: Projected Generation Retirement Capacity Through 2035

[Figure 7](#) shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.¹⁹ MISO continues to lead the assessment areas in the amount of projected retiring capacity at roughly 35 GW.

The yearly projections of future retirements and an assessment area view are provided in the [Risk from Additional Generator Retirements](#) section.

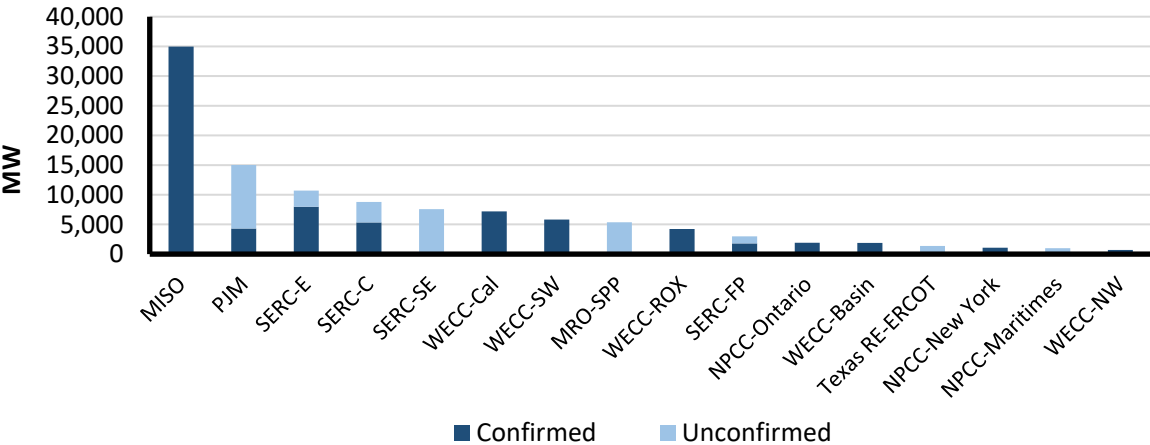


Figure 7: Projected Capacity Retirements of Nuclear and Fossil Generation 2025–2035

assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

Reducing Resource Capacity and Energy Risk

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

Resource Adequacy Program Attributes

Utilities, market operators, and regulators across North America are adapting their resource adequacy programs to address mounting challenges, including load growth, changing load behavior, resource mix transition, extreme weather, and evolving end-use need for electricity. NERC and industry stakeholders have recognized key resource adequacy program attributes that may become needed to address specific challenges faced by system planners and operators. [Table 15](#) includes five of these attributes and a brief description of how the attribute can be implemented. Assuring an adequate supply of electricity requires modernizing planning approaches. NERC encourages each assessment area to evaluate the program attributes needed to plan effectively for current and future challenges and implement those identified as essential.

Table 15: Resource Adequacy Program Attributes		
Attributes	Objective	Implementation
1. Uses Energy Risk Criteria	To ensure energy adequacy in systems with VER and fuel limitations, resource planners and markets need to augment existing 1-day-in-10 load-loss criteria with additional energy risk metrics.	Establish criteria based on EUE or similar energy risk metric(s).
2. Evaluates Resource Contributions at Risk Periods	As periods of shortfall risk on the system change with changing resource and demand characteristics (e.g., risks during winter and summer, peak net demand, and shoulder seasons), methods for assigning resource contributions in resource procurement and assessments must evolve.	Adopt effective load-carrying capability or other probabilistic methods for determining resource contributions during risk periods.
3. Load Forecasting Accounts for Growth Uncertainty	Future electricity demand is being influenced by the pace of electrification, industrialization, data center development, and DER adoption. Load forecasts for adequacy assessment and resource planning need to account for new growth patterns and uncertainty.	Capture the forecast drivers needed for the area and address uncertainties.
4. Considers Effect of Extreme Scenarios on Adequacy	To reduce the unique resource adequacy risks from wide-area extreme weather events, resource adequacy programs should evaluate potential system impacts and weather scenarios to mitigate risk to the BPS.	Analysis considers low-probability energy events (e.g., drought, multi-day weather patterns) and adequacy criteria include load-loss event magnitude and duration.
5. Includes Coordinated Interregional Transfer Capability	Interregional transfer capability can provide enhanced reliability and resilience and is most effective when resource adequacy programs include coordination with neighbors.	Model transfer limits and deliverability; implement processes for seams coordination.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. See [Figure 8](#) for seasonal peak demand growth over the current and prior assessment periods and [Figure 9](#) for net energy growth. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year’s 10-year growth projection of 132 GW. Winter demand growth continues to outpace summer demand growth: The 10-year aggregated winter peak demand is forecast to rise by over 245 GW, a 65% increase from last year’s 149 GW growth projection. Compound annual growth rates (CAGR) for summer and winter peak demand are the highest since NERC’s tracking started in 1995. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in [Figure 10](#).

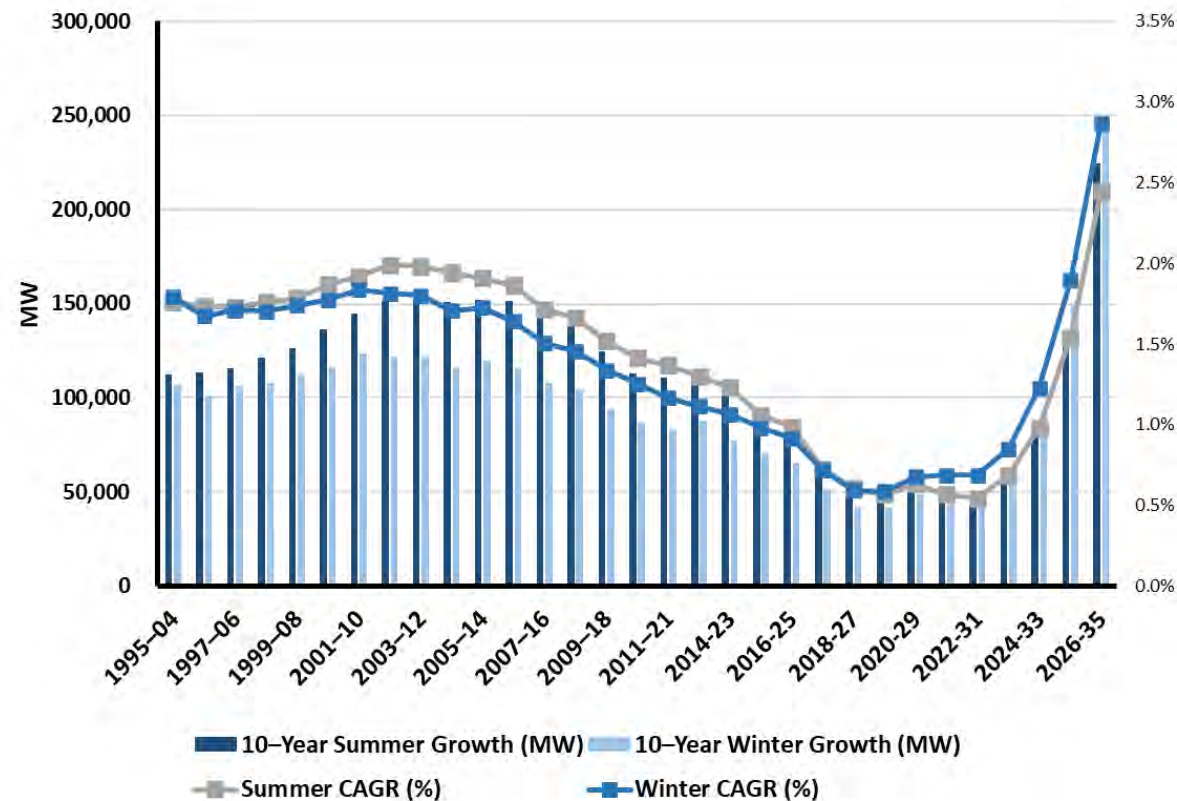


Figure 8: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

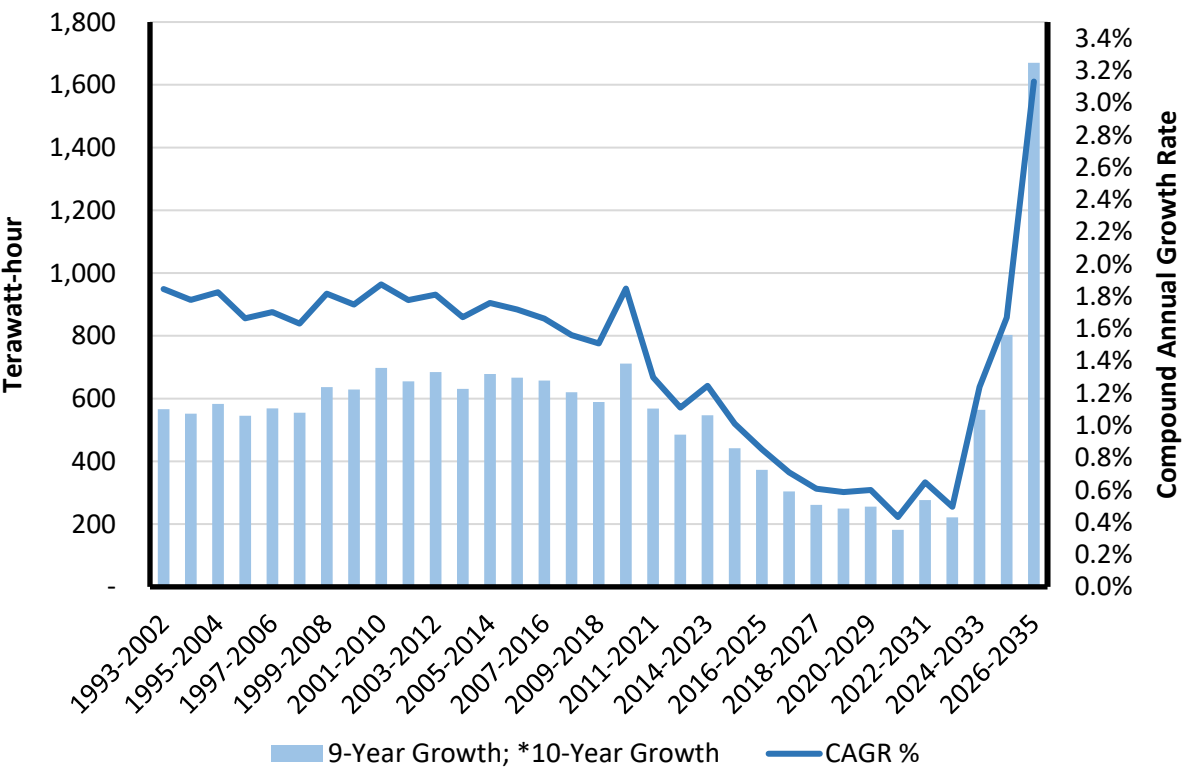


Figure 9: Net Energy for Load Growth and Rate Projections

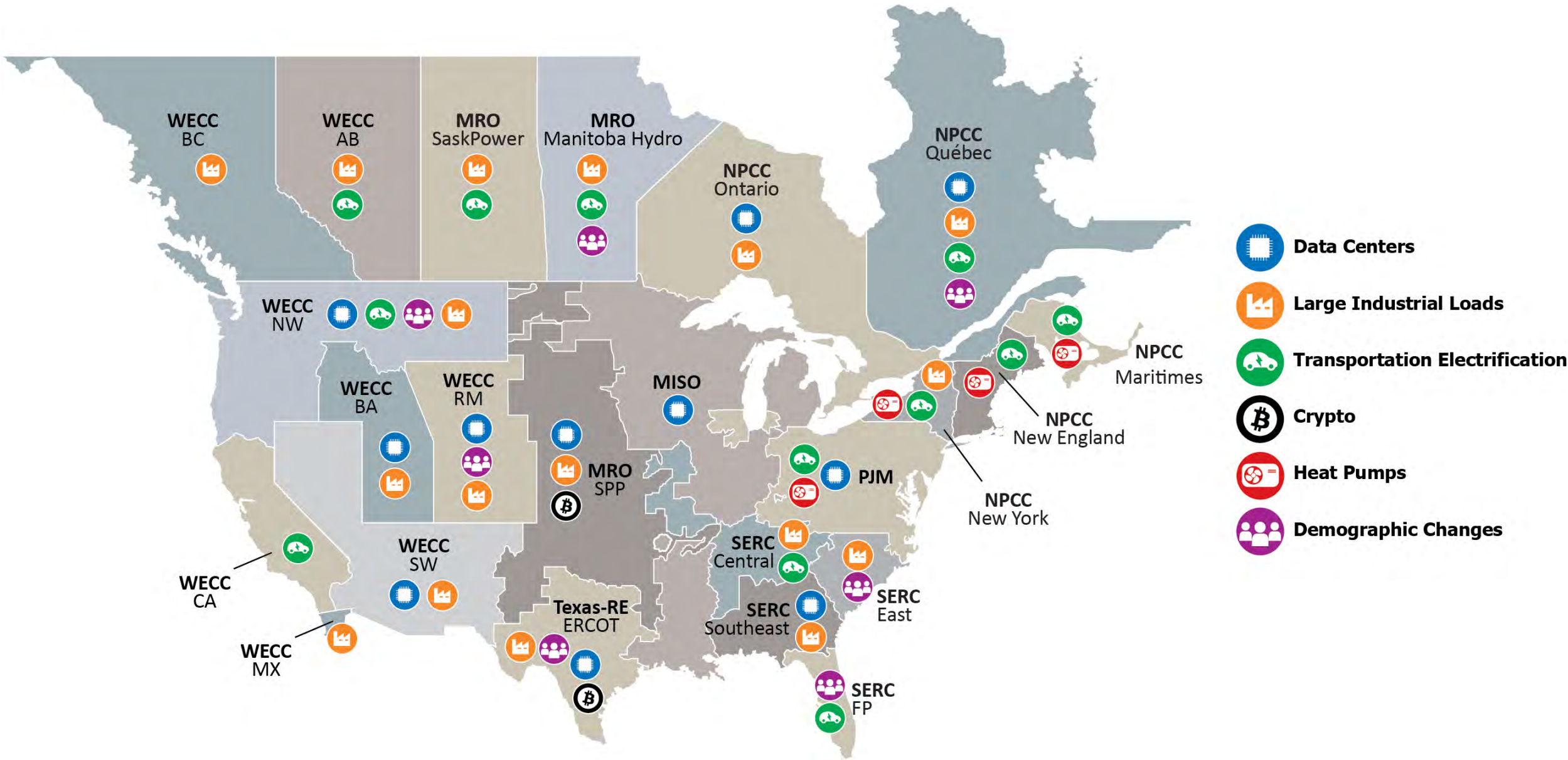


Figure 10: Primary Demand Drivers by Assessment Area

Data Centers and Large Commercial and Industrial Loads

New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years. These and other large commercial and industrial loads are connecting rapidly to the BPS. The emerging large loads present unique challenges to forecasting and planning for increased demand.

Load forecasts collected by NERC for the 2025 LTRA reveal the massive build-out of data centers in many parts of North America. Texas, PJM, and the WECC assessment areas are reporting steep demand increases due primarily to new data centers and large loads. BAs within WECC reported that planned data centers account for an average of 10% of demand, with some BAs reporting as high as 40% of the demand forecast. See Figure 11 and Figure 12 for projections in ERCOT and most WECC assessment areas, respectively.

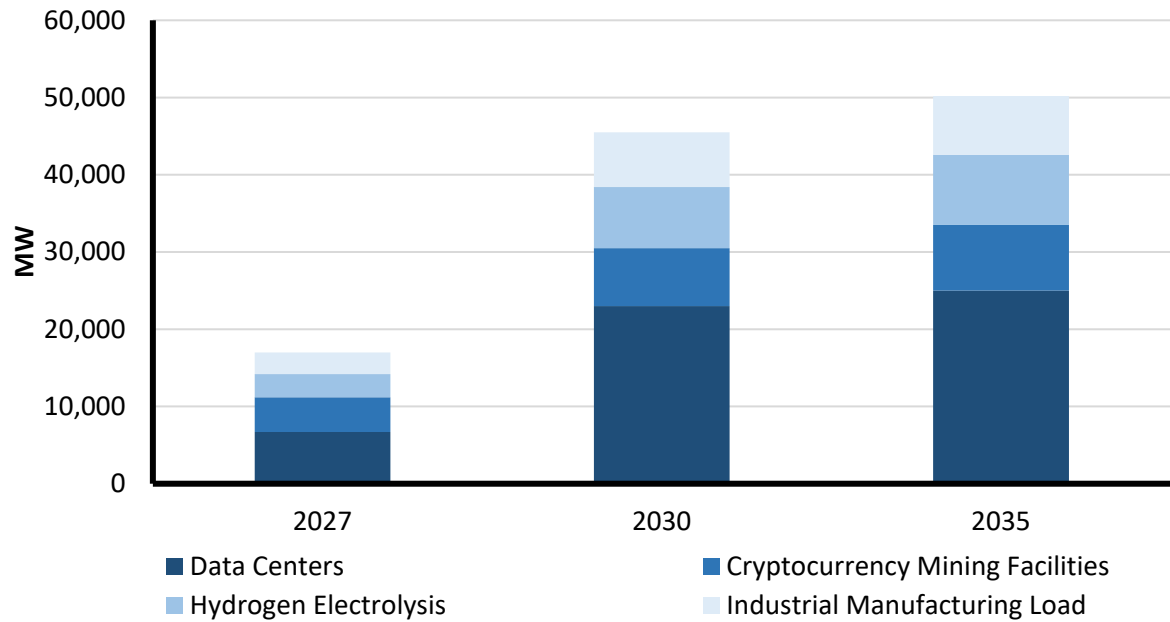


Figure 11: Large-Load Projection Breakdown in ERCOT

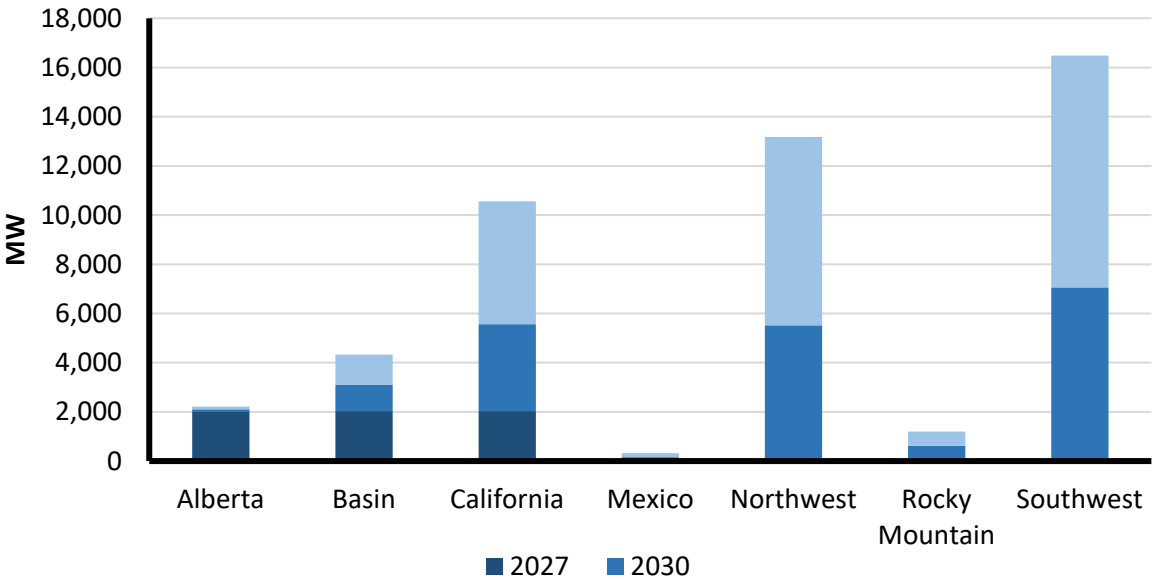


Figure 12: Large-Load Projection by Year in WECC Assessment Areas

Demand forecasts and large load projections throughout the LTRA are based on LSE and BPS system planner forecasts. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Consequently, data center and large load growth forecasts in the LTRA are likely to be more conservative than predictions from the technology industry or from economic, research, academic, and policy organizations.

In Texas, fluctuations in recent large-load interconnections activity continue to affect both near- and long-term demand expectations. Utilities and system operators are also gaining insights from large-load development and operating behaviors and applying them to future forecasts. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. New data center demand projections in Texas are reduced by almost 50% of their original requested load level to reflect the observed consumption behavior of existing data center sites during their initial operations. ERCOT also slashes most new large loads that have yet to enter a contract for transmission service from its long-term demand forecast and adjusts

expected in-service dates to account for historical delays. Similarly, PJM is refining processes for large load forecasting starting with its 2026 load forecast.²⁰

There is already evidence that large loads impact BPS reliability. For example, the Eastern and ERCOT Interconnections have observed load-reduction events²¹ with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction. The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation and caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying size 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’s RSTC established a Large Loads Task Force (LLTF)²² to better understand the reliability implications of growth in large loads and develop solutions. The LLTF published the white paper *Characteristics and Risks of Emerging Large Loads*²³ in 2025, and another white paper, *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*, is forthcoming.²⁴

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the 2024 LTRA, peak season CAGR has risen in all assessment areas except five: MRO-Manitoba Hydro’s winter CAGR fell from 1.79% to 1.37%, MRO-SaskPower’s winter CAGR fell from 1.32% to 0.89%, NPCC-New England’s summer CAGR from 1.28% to 1.05%, NPCC-New York’s summer CAGR from 0.87% to 0.84%, and SERC-East’s summer CAGR fell from 1.88% to 1.17%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are

planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from summer-peaking systems to winter-peaking (or dual-season peaking) systems and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (late-2030s)
- NPCC-Ontario (2030; dual-season peaking)
- Texas RE-ERCOT (2035)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer. In Canada, WECC-Alberta has been operating as a dual-peaking system.

Demand Response

Demand-side management programs are growing for many assessments areas. DR is one form of demand-side management. It consists of mainly commercial and industrial end users that have entered into agreements with load-serving entities to curtail demand when needed by grid operators. DR can assist with reducing load during critical periods of increased demand, such as heat waves or winter storms. Figure 13, Figure 14, and Figure 15 show the increasing projections for DR in the first year of the forecast for the past five LTRA reports in Texas RE-ERCOT, NPCC-Québec, and NPCC-New York, respectively. Other forms of demand-side management include EE and conservation programs administered by utilities. The reported contributions from DR, EE, and conservation programs reduce total electricity demand in load forecasts and provide reliability benefits that are accounted in LTRA reserve margin calculations and the ProbAs.

²⁰ Planned revisions to PJM’s treatment of large load forecasts from PJM’s Load Analysis Subcommittee: [20250613-item-03--large-load-adjustment-process-improvement-discussion.pdf](#)
²¹ “Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions,” NERC, Jan. 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf

²² NERC Large Loads Task Force webpage: [Large Loads Task Force \(LLTF\)](#)
²³ The LLTF’s *Characteristics and Risks of Emerging Large Loads* White Paper
²⁴ The LLTF’s [action plan](#) is updated regularly and contains links to white papers, guidance, and presentations.

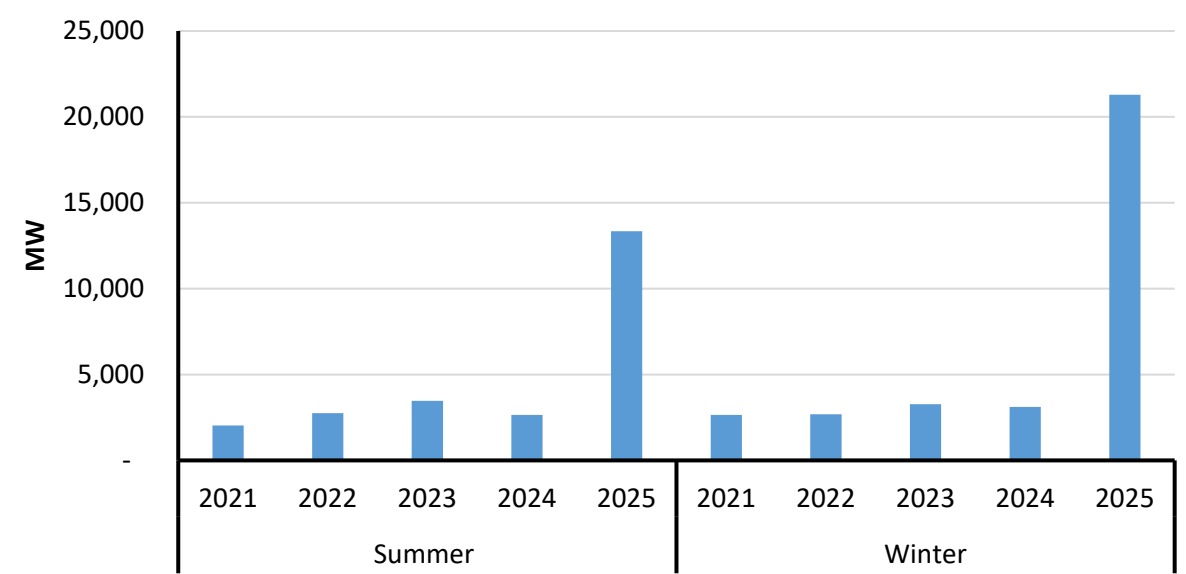


Figure 13: Texas RE-ERCOT Demand-Response Trend in Past Five LTRAs (Year 1)

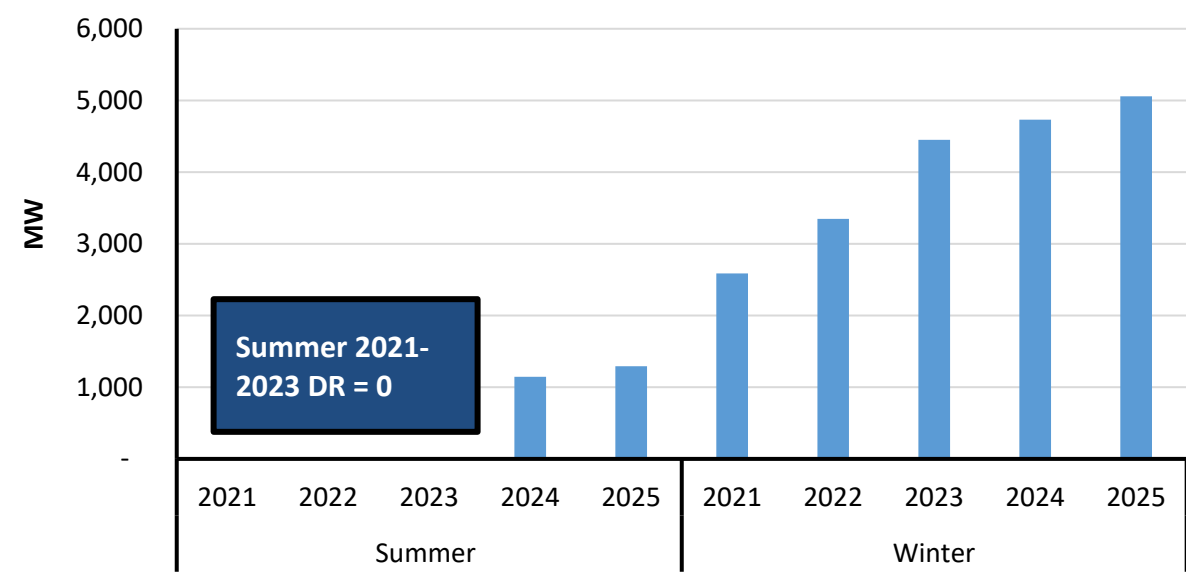


Figure 14: NPCC-Québec Demand-Response Trend in Past Five LTRAs (Year 1)

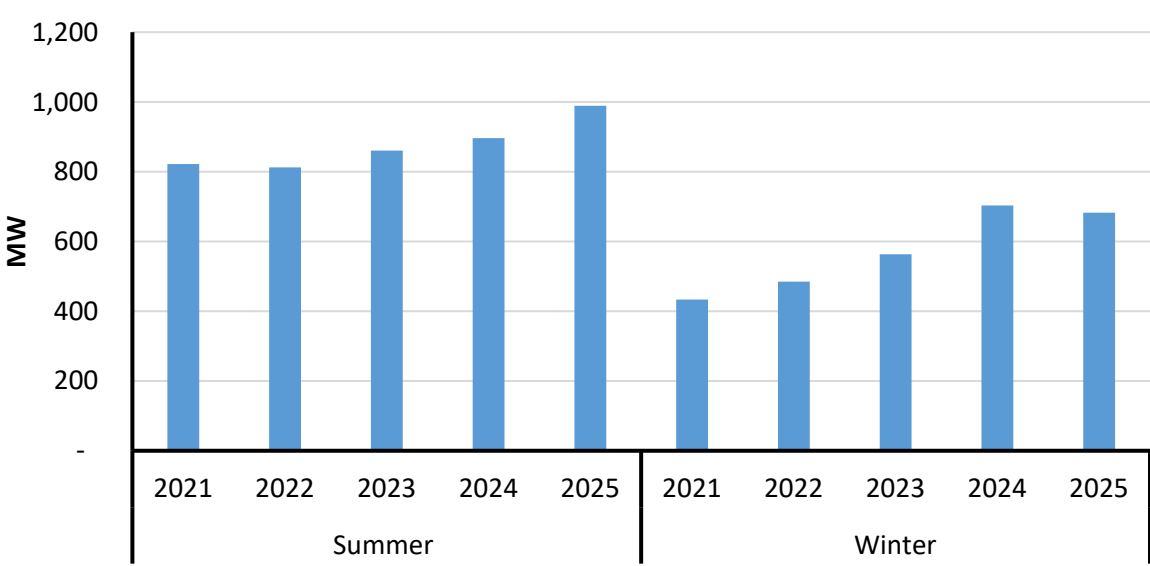


Figure 15: NPCC-New York Demand-Response Trend in Past Five LTRAs (Year 1)

Reliability Implications

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

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

Resource Mix Changes

On-peak resource capacity increased approximately 6.2 GW across the interconnected North American BPS over the last year. This is down from approximately 8.3 GW of net on-peak capacity additions reported a year ago in the *2024 LTRA*. Net capacity from fossil-fueled generators continued to decline at a rapid pace over the last year with approximately 21 GW leaving the system. Continent-wide, net BPS additions of battery, wind, and solar resources totaled 23 GW over the last year (see [Table 16](#)).

Table 16: Existing BPS Resource On-Peak Capacity			
Resource Type	2024 Capacity (MW)	2025 Capacity (MW)	Difference (MW)
Coal	180,402	166,799	– 13,603
Petroleum	30,987	27,931	– 3,056
Natural Gas	484,148	479,901	– 4,247
Biomass	7,381	7,181	– 200
Solar	66,293	70,723	+ 4,430
Wind	31,370	35,121	+ 3,751
Geothermal	3,881	2,932	– 949
Conventional Hydro	105,792	111,117	+ 5,325
Run-of-River Hydro	2,047	2,017	– 30
Pumped Storage	19,422	19,734	+ 312
Nuclear	105,384	105,389	+ 5
Hybrid	1,322	1,102	– 220
Other	774	830	+ 56
Battery	8,587	23,267	+ 14,680
Total	1,047,790	1,068,514	+ 6,254

Like last year, the anticipated BPS generating capacity (i.e., capacity from existing generation + expected additions – expected generator retirements) fell short of industry projections reported in the LTRA, furthering the concerns that accelerating peak demand growth is continuing to outpace the supply resources.

Figure 16 compares this year's existing and Tier 1 nameplate and on-peak capacity against the actual current capacities derived from data collected for this year's LTRA. Bars that cross the 100% line represent resources with actual additions exceeding projections from 2024, and bars that fall to the left of the 100% line represent resource types with actual additions less than projected in 2024.

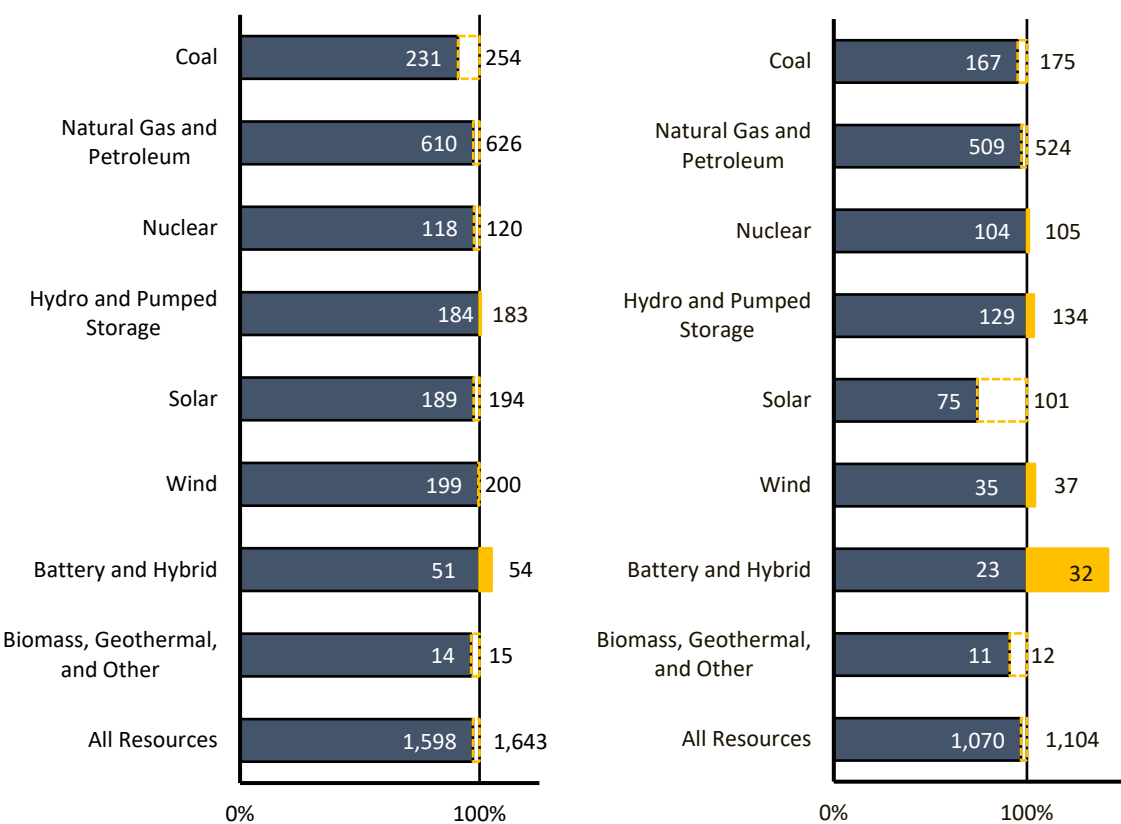


Figure 16: Comparison of North America's 2025 Existing and Tier 1 Nameplate (Left) and On-Peak (Right) Capacities in GW to 2024 LTRA Projections

Continuing the trend from last year, battery energy storage systems were added to the system faster than expected, while coal, natural gas and petroleum, and solar resources were once again over-projected. As coal capacity continued its decline because of plant retirements and age-related derating, its over-projection from last year means that it left the system faster than anticipated in 2025.

Notably, the capacity contribution of VERs, including solar, wind, battery, and some types of hydroelectric generation, to serving load at peak demand differs from the nameplate, or installed capacity. The right plot in **Figure 16** above includes a complementary view to the on-peak projections using nameplate capacity to accommodate different capacity accounting methods. Both 2025 on-peak and nameplate solar was over-projected across the North American BPS last year. These over-

projections continue to support electric industry reports of construction delays and project withdrawals prior to commercial operations that prevented the expected interconnection of new resources.

Planned On-Peak Capacity Additions

New resources are added to the BPS through each area’s interconnection planning process. Entities have expressed concerns that the pace of resource additions has been too slow to meet demand growth and future retirements in the existing generator fleet. Figure 16 above highlights that industry participants are expecting peak demand growth of nearly 250 GW over the next 10 years because of accelerating demand for a variety of electricity users. Planning for such explosive growth and the uncertainty about its magnitude and timing is a complicated challenge for system planners.

Figure 17 illustrates the planned on-peak capacity additions and subtractions across the North American BPS over the next 10 years. Additions are illustrated by the positive portions of the stacked columns and include both Tier 1 and Tier 2 additions. In general, Tier 1 resources are in the final stages for connection, while Tier 2 resources are further from completion (see Demand Assumptions and Resource Categories). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. Deratings and retirements of the existing fleet are stacked in the negative Y direction with diagonal hatching patterns.

To keep up with forecasted demand growth and generator retirements, planned resources with interconnection agreements will need to come in on time, and additional resources in development must mature through the interconnection process quickly (see Figure 18). The on-peak capacity of approved resource additions found in integrated resource plans (IRP) and ISO/RTO expansion plans through 2028 is able to keep pace with the aggregated peak demand forecasts of all NERC assessment areas. Beyond 2028, new approvals for resource additions are required to maintain robust growth. Furthermore, additional generation is needed to make up for capacity lost to generator retirements. Considering the generator retirements depicted in Figure 17, there are only approximately 60 GW of net additions planned in the most certain Tier 1 category over the next 10 years. Another 190 GW of Tier 2 or other resources (70% of Tier 2’s 10-year total) would need to complete the interconnection planning process and reach commercial operations to meet the expected demand growth, illustrating the pressure on resource and system planning to rapidly add resources. DR programs, EE improvements, and transmission development to enable interregional transfers that take advantage of geographic diversity can also support growing demand.

To respond to this urgent need for new resources, independent system operators and regional transmission organizations have been developing new market structures and products to retain

capacity and expedite interconnection of new generation and storage. Three such programs established by ISO/RTOs are PJM’s Reliability Resource Initiative, MISO’s ERAS process, and SPP’s Expedited Resource Adequacy Study.

In a shift from a key insight from the 2024 LTRA, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year’s 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown only modestly since the 2024 LTRA by 7 GW (1.7%) as compared to a year-over-year growth of 44 GW last year.

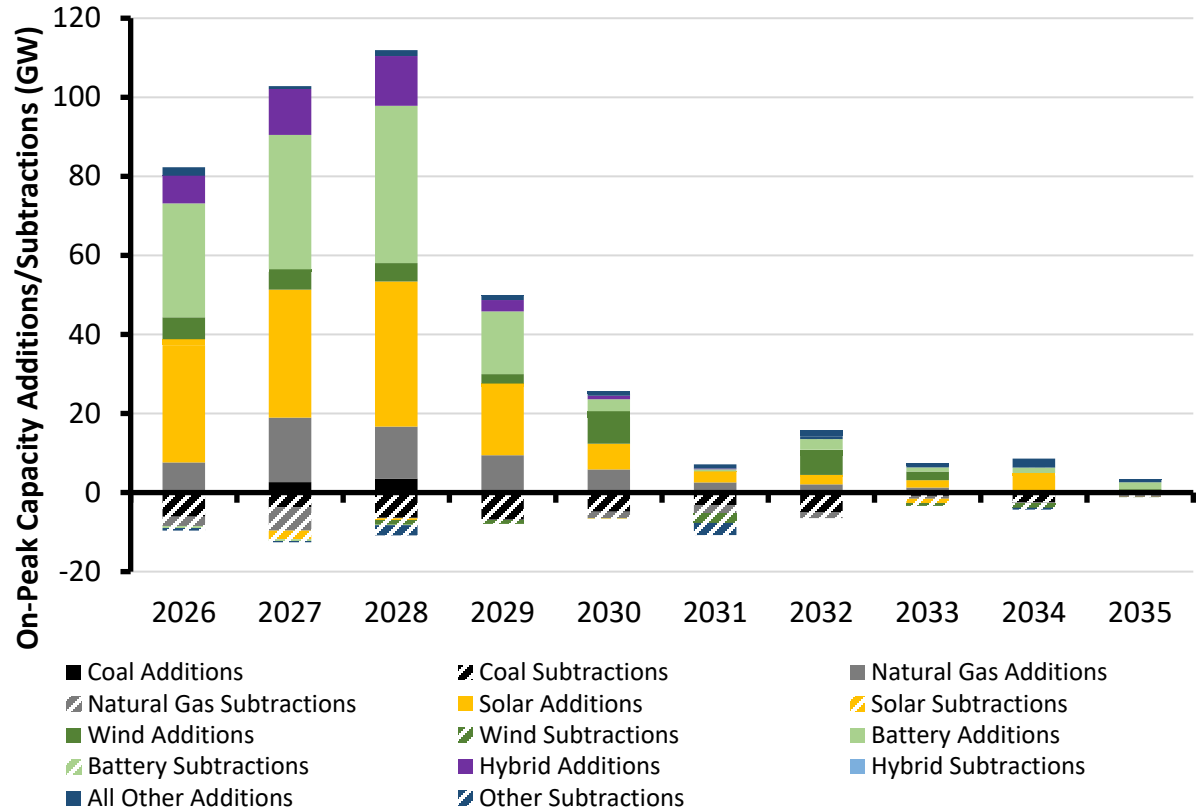


Figure 17: Projected Annual On-Peak Capacity Additions and Subtractions by Resource Type and Net Cumulative Capacity Changes

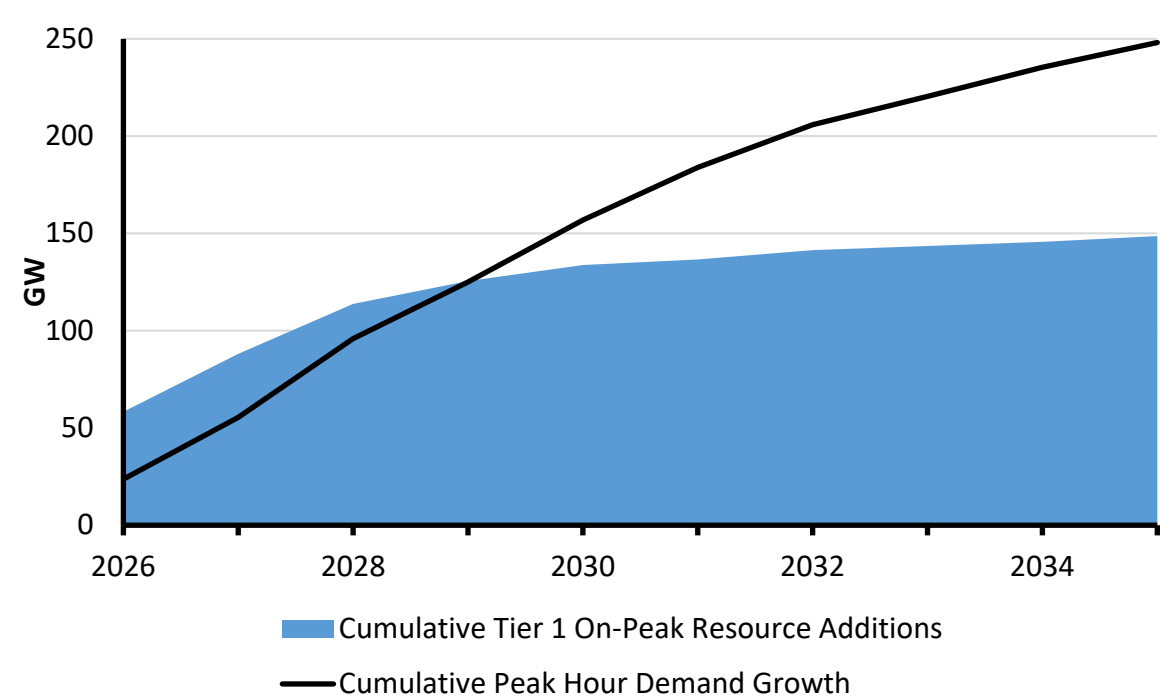


Figure 18: Expected BPS Resource Additions (Tier 1) and Aggregated BPS Peak Demand Growth Through 2035

Increasing On-Peak Share of Variable Resources

Year-over-year increases in the fraction of on-peak capacity provided by VERs—run-of-river hydro, solar, and wind—have continued since the 2024 LTRA with VER on-peak contributions increasing from 9.5% to 10.2%. This observed trend is projected to continue through 2035 with shares of on-peak VER capacity projected to rise to between 15% and 20% depending on the completion and interconnection of Tier 1 and Tier 2 resources. [Figure 19](#) shows existing on-peak capacity by resource type for 2024 and 2025 along with projected on-peak capacity by resource type for 2035 with Tier 1 and Tier 2 additions. Resource types with on-peak shares less than 5% are not labeled with their contribution fraction but are stacked in the graphic.

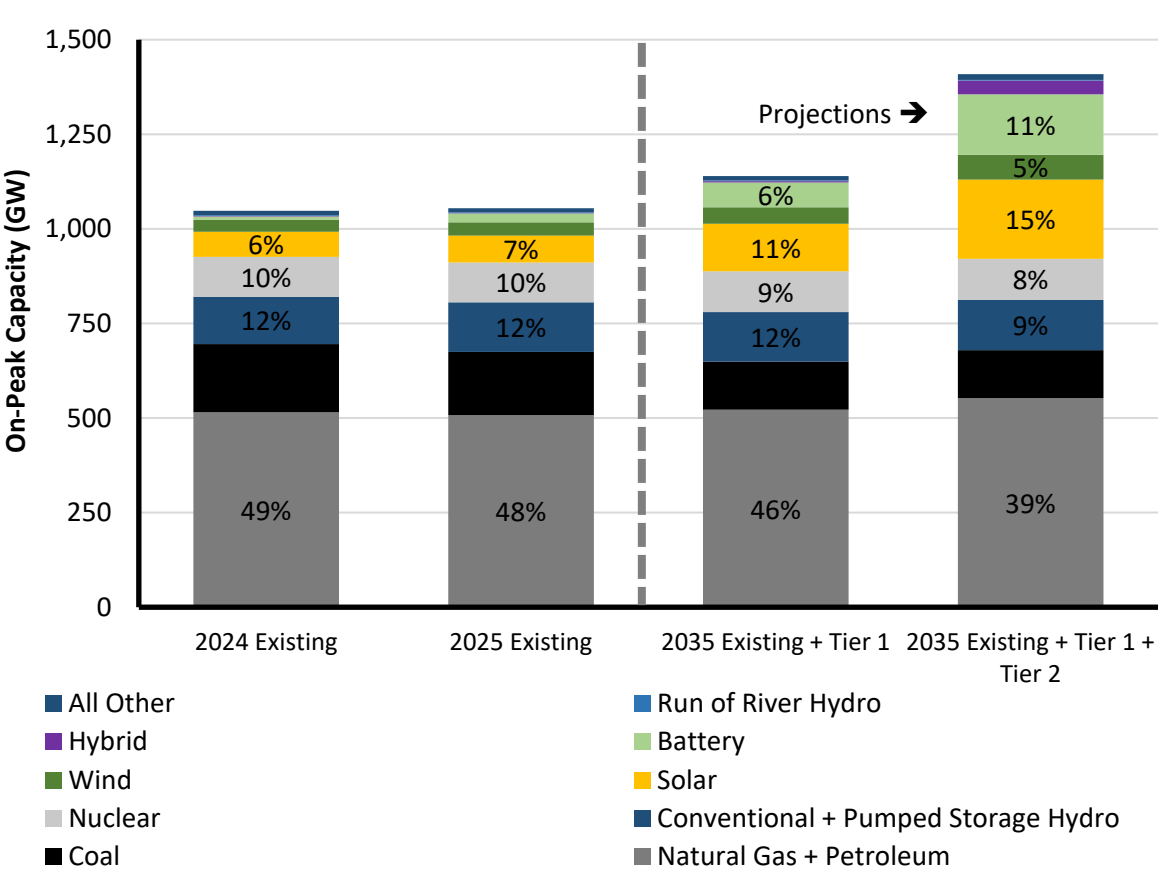


Figure 19: North America On-Peak Capacity Shares by Resource Type

Like last year, a relatively small change in total on-peak capacity was observed, but the continued trend of increasing VER share highlights that important reliability attributes continue to leave the system. Non-variable generation—including coal, petroleum, natural gas, biomass, geothermal, conventional hydro, and nuclear—as well as hybrid or storage systems can ramp up or down in response to demand. Non-variable resources can also provide other ERSs like system inertia, dynamic reactive support, and frequency response for stable grid operation. Many of the variable resources that are being added to the grid to replace non-variable resources cannot provide the same ERSs in their current configuration. This deficiency is amplified in the winter when on-peak contributions from variable resources are diminished by changing weather and environmental conditions.

System Frequency Response Analysis

Despite lower inertia from retiring synchronous generators and greater penetration of inverter-based resources, all four Interconnections expect adequate, diverse frequency response capabilities and a low risk of under-frequency load shedding (UFLS) activation. In preparing the 2025 LTRA, NERC worked with the Regional Entities and system planners to assess the frequency response capability of the projected resource mix through 2027 on an Interconnection basis. The findings are summarized in Table 17.

Table 17: Measures of Frequency Response		
Measure	What it Measures	Summary Assessment Findings
Synchronous Inertial Response (Measure 1)	The minimum inertial response amount (total stored kinetic energy) projected in each Interconnection	Despite the retirement of synchronous generation over the past eight years, there appears to be more than sufficient inertia within all Interconnections. ERCOT’s use of load response to respond to frequency disruptions is effective in supporting low-inertia conditions.
Rate of Change of Frequency (Measure 2)	The calculated rate of frequency decline within the first 0.5 seconds following the largest credible contingency	No negative trends identified. Texas RE-ERCOT studies show that load response is extremely effective in arresting frequency due to its ability to perform very quickly.
Frequency Response Performance (Measure 4)	Simulated dynamic behavior of an Interconnection’s response to the largest credible contingency	Simulations in both the Eastern and Western Interconnection show sufficient frequency response in future planning cases.

The results of analysis for each Interconnection are in Table 18. Non-synchronous resources have increased in all Interconnections since the last LTRA frequency response analysis in 2022. Each interconnection continues to project sufficient frequency response ERSs in the near term and have low likelihood of UFLS activation during a disturbance. These results were determined by dynamic

²⁵ EIPC Frequency Response Report

²⁶ 42.9% is the penetration of utility-scale non-synchronous generation. The Western Interconnection has a significant amount of DERs that are also non-synchronous. When DERs are included, the non-synchronous penetration was 54.9%.

²⁷ ERCOT procures responsive reserve service to protect from involuntary under frequency load shed after loss of two largest generating units at a single plant (2,805 MW). In March 2020, a new subproduct of responsive reserve service was

studies performed for the Eastern, Western, and Québec Interconnections and analysis of operational procedures for the Texas Interconnection.

Table 18: Summary of the Results of NERC Frequency Response Sufficiency Assessment				
Interconnection	Highest Non-Synchronous Penetration at Minimum Inertia Studied	Number of Critical Inertia Conditions Reached?	Lowest Frequency Nadir Observed in Planning Studies	Likelihood of Credible Disturbance Resulting in UFLS Activation
Eastern Interconnection	17.9% ²⁵	0	59.93 Hz	Low
Western Interconnection	42.9% ²⁶	0	59.65 Hz	Low
Texas Interconnection	65.7%	0	N/A	Low ²⁷
Québec Interconnection	37%	0	N/A	Low

Increasing Natural Gas Reliance

In 2024, natural-gas-fired power plants generated approximately 43.4% of all electricity generated in the United States, according to the U.S. Energy Information Administration, up from 43.2% in 2023. As of August 2025, natural-gas-fired power plants in the United States are on track to generate a slightly smaller share of electricity this year in comparison to last year, but accelerating energy demand through the remainder of the year and projected increases in net energy for load over the next 10 years indicate that natural-gas-fired generators will remain critical resources for BPS reliability in many areas.

Natural-gas-fired generators are especially important during the winter. Winter peak electricity demand in most areas occurs during early morning hours when unavailability of weather-dependent resources leads to a surge in natural-gas-fired generation’s share of the resource mix. Severe winter weather events in 2021 and 2022 provide stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure fuel supplies during times of extreme electricity demand.

introduced, FFR, which is triggered at 59.85 Hz within 0.25 seconds. Up to 450 MW of FFR can be procured as a part of responsive reserve service. This product is still going through implementation stages due to required changes to ERCOT systems.

Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to slightly more than 12 GW of new natural-gas-fired winter capacity if only the most certain Tier 1 resources come on-line. That number jumps to 41 GW of new natural-gas-fired winter capacity if both Tier 1 and Tier 2 resources come on-line (see [Figure 20](#)). Importantly, the vast majority of natural-gas-fired Tier 1 and Tier 2 additions—11 to 39 GW—are projected to come on-line in the next five years.

The timing and magnitude of natural-gas-fired generator additions remains uncertain in today’s energy system planning environment. Multiple areas are conducting expedited resource assessments and interconnection process reforms with goals of adding more generator capacity to the grid over the next few years to meet rapidly accelerating electricity demands, particularly due to large-load addition. The early project submissions and selections from these programs indicate that actual natural-gas-fired additions may exceed previous industry projections in some areas. For instance, PJM Interconnection’s [Reliability Resource Initiative](#) has led to the selection of approximately 8 GW of natural-gas-fired generator uprates and additions out of the nearly 17 GW of natural-gas-fired projects submitted for consideration. Round one selections for MISO’s [ERAS](#) include approximately 4 GW of natural-gas-fired additions out of the 20 GW submitted to date, and SPP’s *Expedited Resource Adequacy Study* includes approximately 9 GW of natural-gas-fired winter capacity additions in its interconnection queue. Most of these expedited additions that have been selected across all three programs have applied to come on-line before 2030.

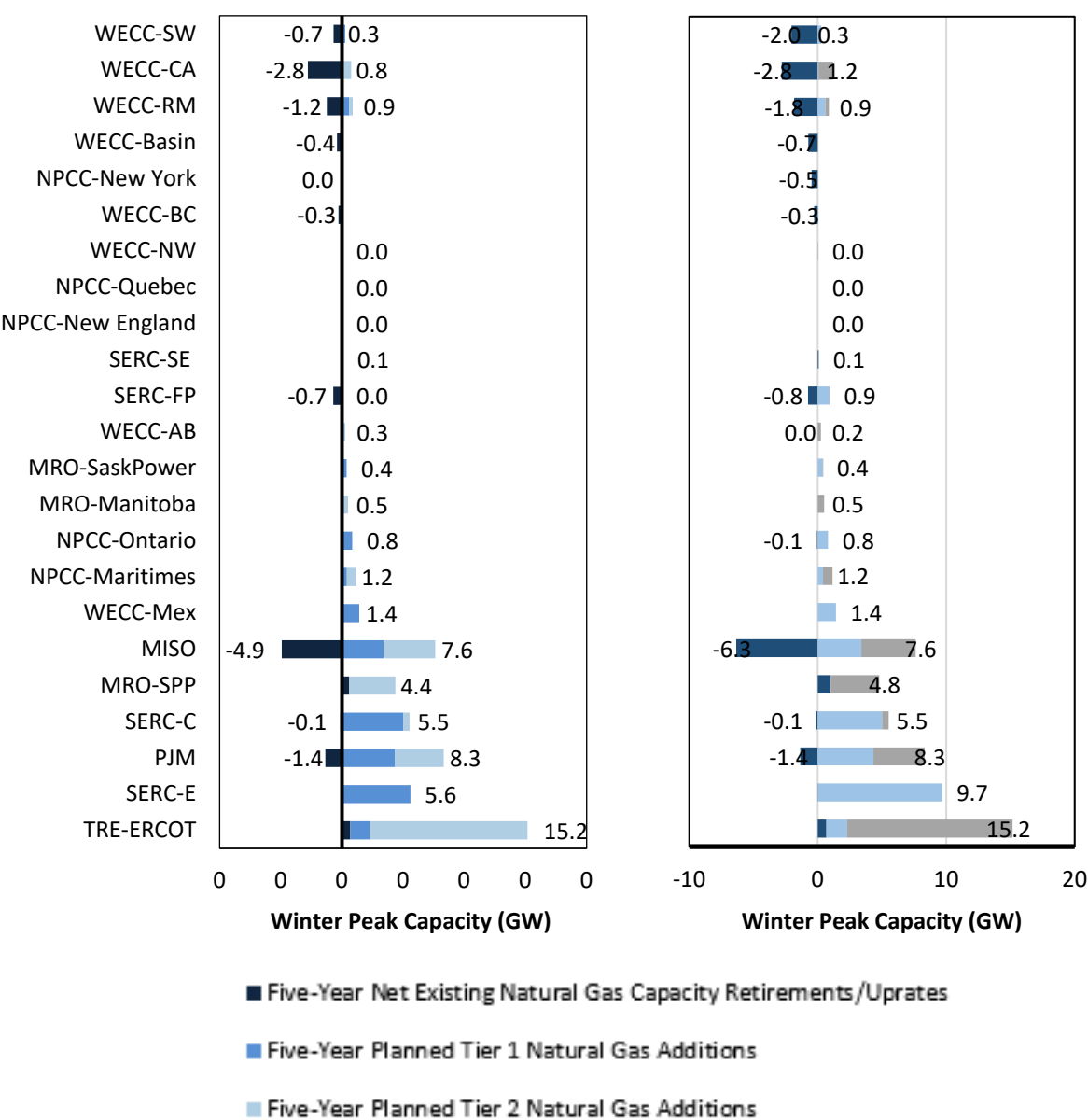


Figure 20: 5-Year (Left) and 10-Year (Right) Projected Natural-Gas-Fired Winter Capacity Additions by NERC Assessment Area

Natural Gas Infrastructure Development

Natural gas system planners have increasingly been coordinating with electric system planners to prepare for large additions to the natural-gas-fired power plant fleet. However, processes, regulations, and financial mechanisms that underpin capital investments and expansion of the natural gas pipeline and production system at times do not align with the variable operations of critical natural-gas-fired generators. For these reasons, among others, a significant percentage of natural-gas-fired power plants continue to rely on interruptible, or non-firm, supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas for both electricity generation and space heating can both dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability. When winter weather also impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can imperil even firm pipeline customers’ supply as preparatory linepack is rapidly depleted.

There is a possibility that generators in the areas that are adding the most gas resources—MISO, MRO-SPP, PJM, SERC-C, SERC-E, and TRE-ERCOT—could secure additional firm fuel supplies from natural gas system projects planned or proposed over the next decade. **Figure 21** shows the amount of incremental natural gas pipeline capacity with in-service dates spanning the next five years. In total, S&P Global Energy projects that roughly 45 BCF/day of incremental natural gas pipeline capacity created by additional compression, expansions, pipeline repurposing, new pipelines, or reversal of flow directions will be built over the next decade. About one-third of this incremental capacity has gained regulatory approval and moved into the more formal stages of project development. Of the 15 BCF/day of regulatory approved gas pipeline capacity additions, only 5 BCF/day is planned to serve natural gas demand in the states outside of the Gulf Coast region.

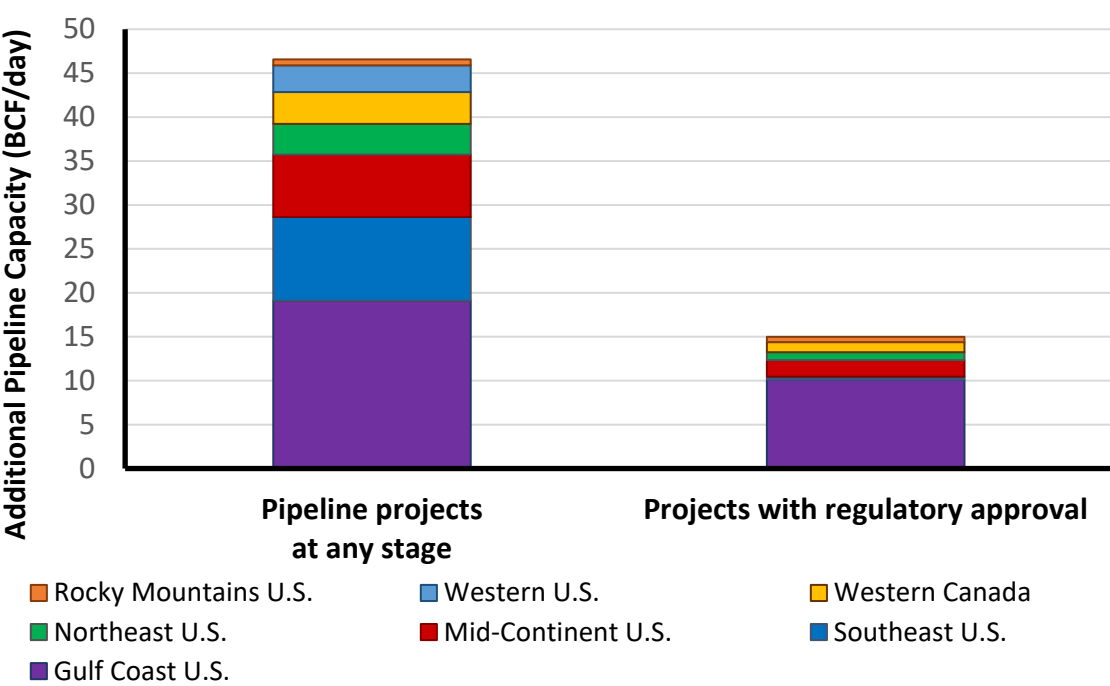


Figure 21: Projected Natural Gas Pipeline Capacity Expansion Projects by Project Stage (Source: S&P Global Energy)

The nearly 40 GW of natural-gas-fired winter capacity additions in the six areas adding the most gas resources could consume as much as 6–11 BCF/day of natural gas during a peak winter day after factoring plant type, efficiency, and whether the generator designated by its grid operator as a critical on-peak resource. While enough incremental pipeline additions to support this anticipated increase in gas demand seem to be moving through the natural gas project development process in those regions (see [Figure 22](#)), generators will need to compete with other pipeline customers for firm supply and delivery during periods of high gas demand. The magnitude of gas pipeline capacity additions suggests that there may be promising opportunities for generators to procure firm gas pipeline and supply contracts, but regulatory approval does not assure construction or commercial operation. In addition, if firm gas contracts cannot be secured for coincident high gas and electricity demand periods, like winter, ongoing critical generator projects might need to consider backup fuel capabilities so that they can assure fuel availability.

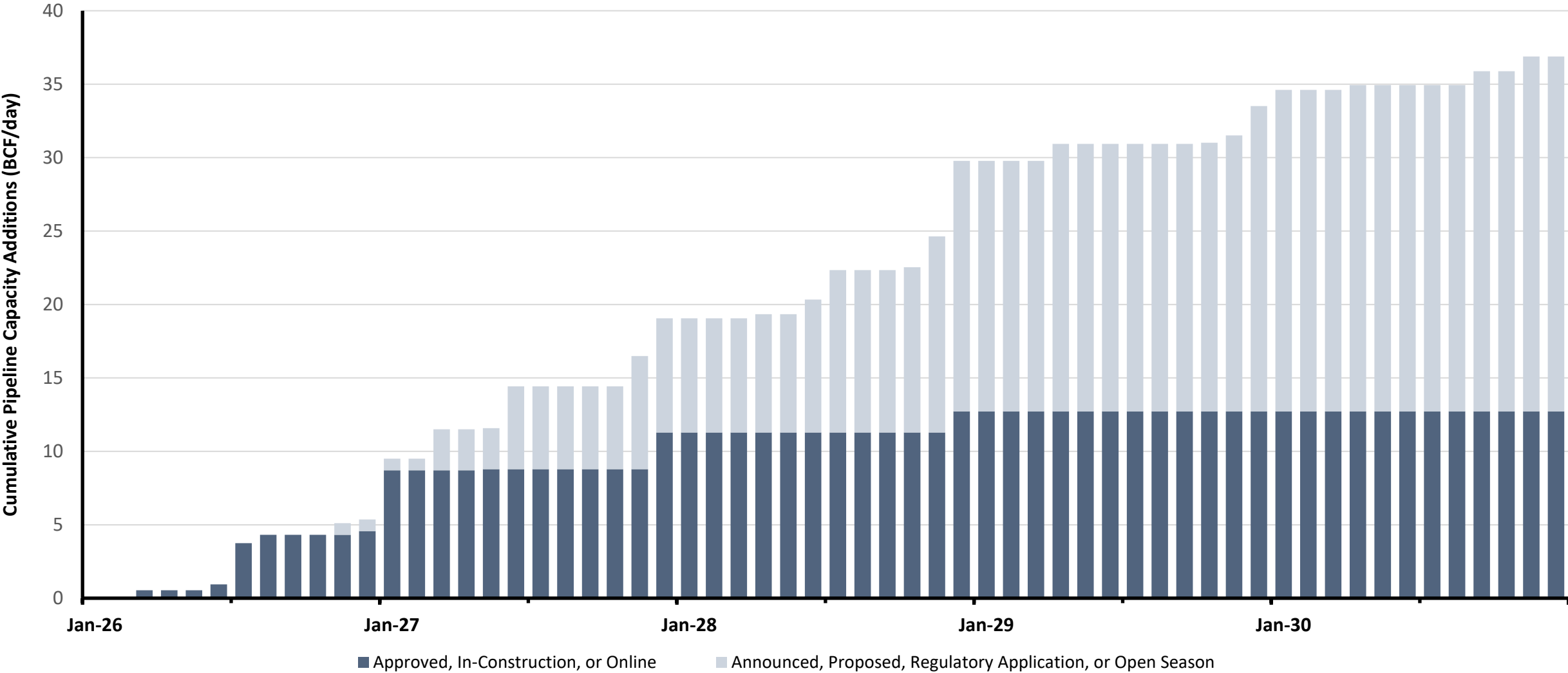


Figure 22: Projected Natural Gas Pipeline Capacity Expansion Projects Ending in MISO, PJM, SERC-C, SERC-E, SPP, and TRE-ERCOT Areas (Source: S&P Global Energy)

Transmission Development and Interregional Transfer Capability

Transmission Projects

This year’s cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years (see [Figure 23](#)) is substantially higher than the 2024 LTRA 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

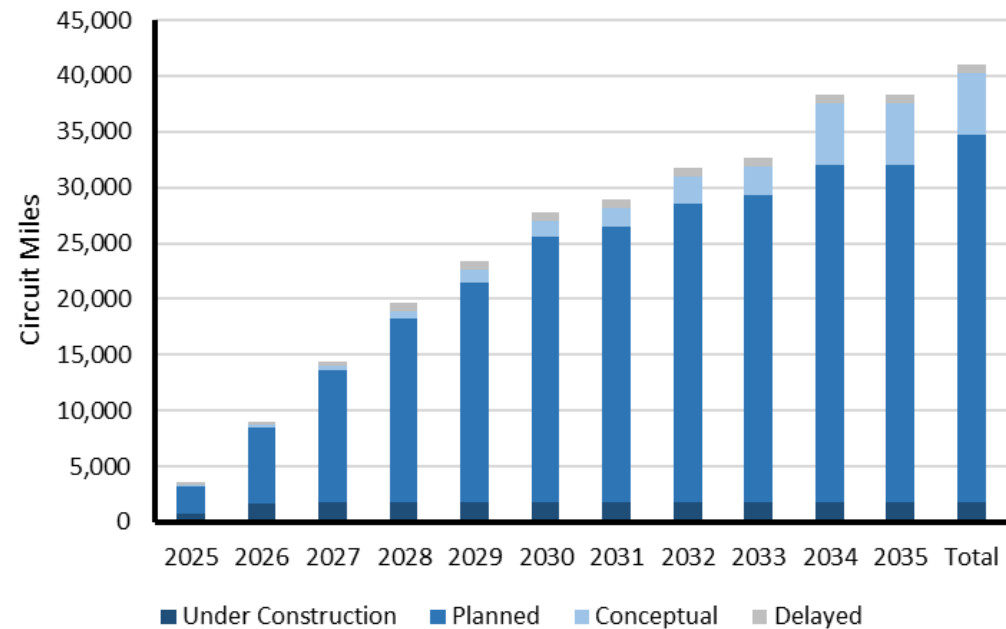


Figure 23: Future Transmission Circuit Miles > 100 kV by Project Status²⁸

Transmission flow patterns are changing and becoming more dynamic with resource shifts. New transmission projects are being driven by reliability, which includes efforts to replace aging infrastructure, integrate renewable generation, retire existing power plants, or meet increased demand forecasts. One such example is Hydro-Québec’s plan to add significant new generating capacity by 2035, which necessitates several major EHV transmission projects. Similarly, several PCs have recently approved, or are actively contemplating, expansive EHV overlays on their systems to

²⁸ The column at right is the total transmission projects reported to NERC and includes projects that did not specify an expected in-service date.

address a variety of needs, including ERCOT, SPP, MISO, PJM, British Columbia, and IESO. [Figure 24](#) shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria.

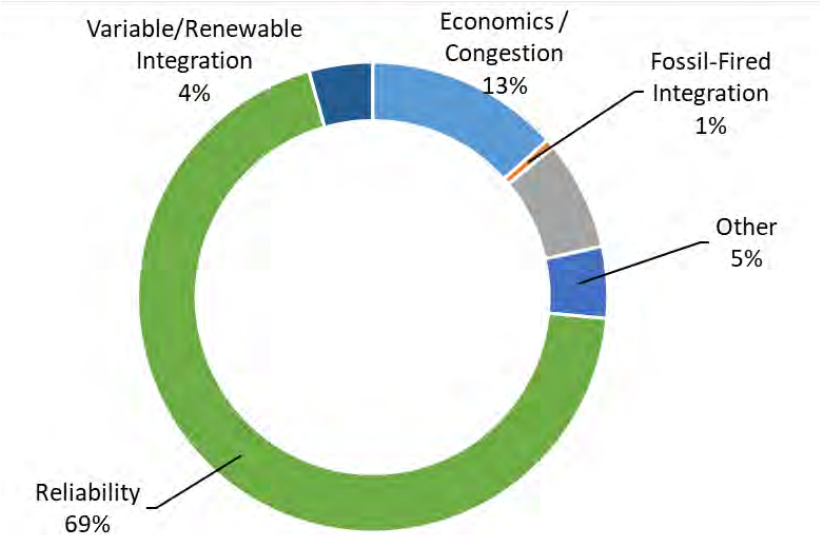


Figure 24: Future Transmission Circuit Miles by Primary Driver

There were 14,150 circuit miles (22,775 km) of reported transmission in development with an operating class greater than 400 kV (about 35% of the total miles in development). Nevertheless, intraregional transmission projects continue to greatly outnumber interregional transmission expansion. These interregional transmission projects can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,²⁹ including scenarios identified in the ITCS. Only 38 of the 863 transmission projects in development are for tie-lines and tie-line upgrades (down from 70 in last year’s LTRA), which can support transfer capability between neighboring BA areas, including high-capacity dc interconnections, such as the 1,200 MW Appalachies-Maine (NECEC) and the 1,250 MW Hertel-New York (CHPE) projects. NYISO has identified a reliability risk if the CHPE project is not completed in a timely fashion. See the transmission summaries at the end of each assessment area’s pages (in the [Regional Assessments Dashboards](#)) for current transmission development details.

²⁹ [Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022 | Federal Energy Regulatory Commission](#)

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays as well as regulatory obstacles, such as siting and permitting. Other reasons for delays include economic impacts, planning and construction issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

Interregional Transfer Capability Study (Canadian Analysis)

In the 2024 LTRA, NERC provided a summary of the ITCS, a comprehensive study of existing and future interregional transfer capability undertaken by NERC in response to the Fiscal Responsibility Act of 2023. In addressing this legislation, NERC identified additions to transfer capability³⁰ for U.S. transmission planning regions (TPR) that could support energy adequacy.³¹ NERC filed the completed study report with FERC on November 19, 2024.³² Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces. The [ITCS Canadian Analysis](#) (Canadian Analysis) was published in April 2025.

The Canadian Analysis was the first-of-its-kind assessment of transfer capability and hourly energy margin analysis in Canada under a common set of assumptions but did not represent a transmission plan or blueprint. Transmission assessments, like the Canadian Analysis, are crucial to understanding potential options to mitigate future risks; however, alternative approaches other than transmission, such as local generation or demand-side solutions, can also mitigate future energy risks. The study results should be considered as an input into subsequent planning discussions that will consider broader objectives and the cost effectiveness of different alternatives to meet long-term needs.

Transfer Capability Analysis

The current transfer capability analysis between each pair of neighboring TPRs focused on 2024 Summer and 2024/25 Winter cases, with results shown in [Figure 25](#) and [Figure 26](#), respectively. These transfer capabilities represent the ability of the entire network to move energy from one TPR to another TPR³³ but are not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities.

³⁰ Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions.

³¹ As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet

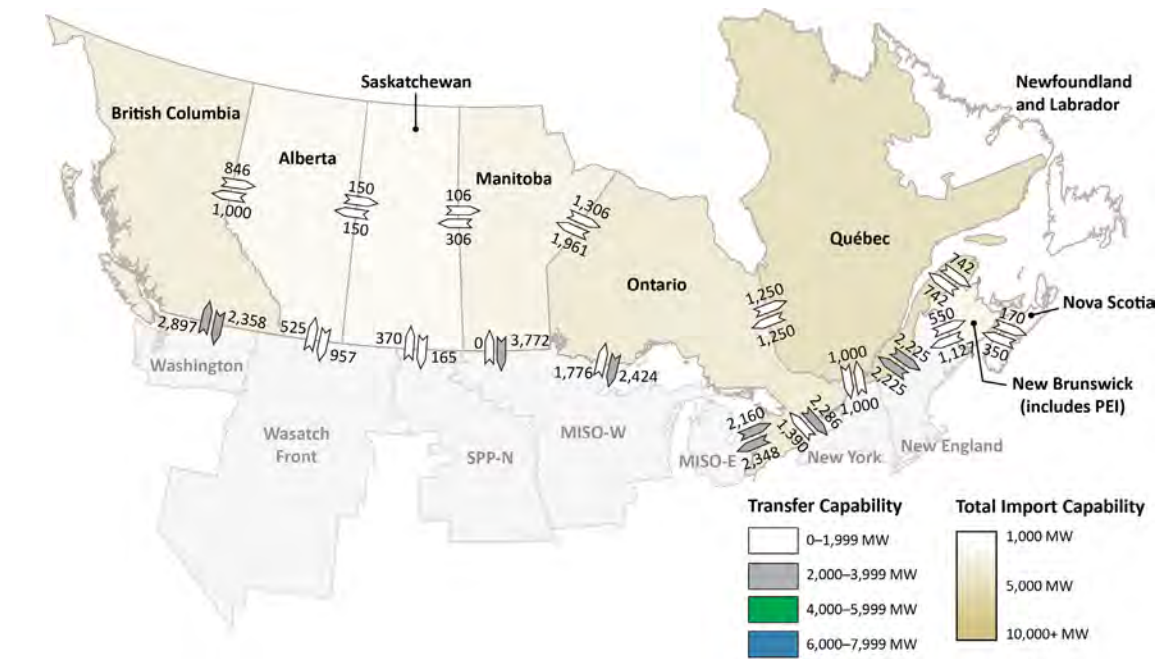


Figure 25: Transfer Capabilities (Summer)

customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.

³² NERC [filing](#) of the *Interregional Transfer Capability Study*, FERC Docket AD25-4-000.

³³ Transfer capability is not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities. Since this study did not follow a path-based calculation method used by many TPRs, results generally do not match individual facility ratings.

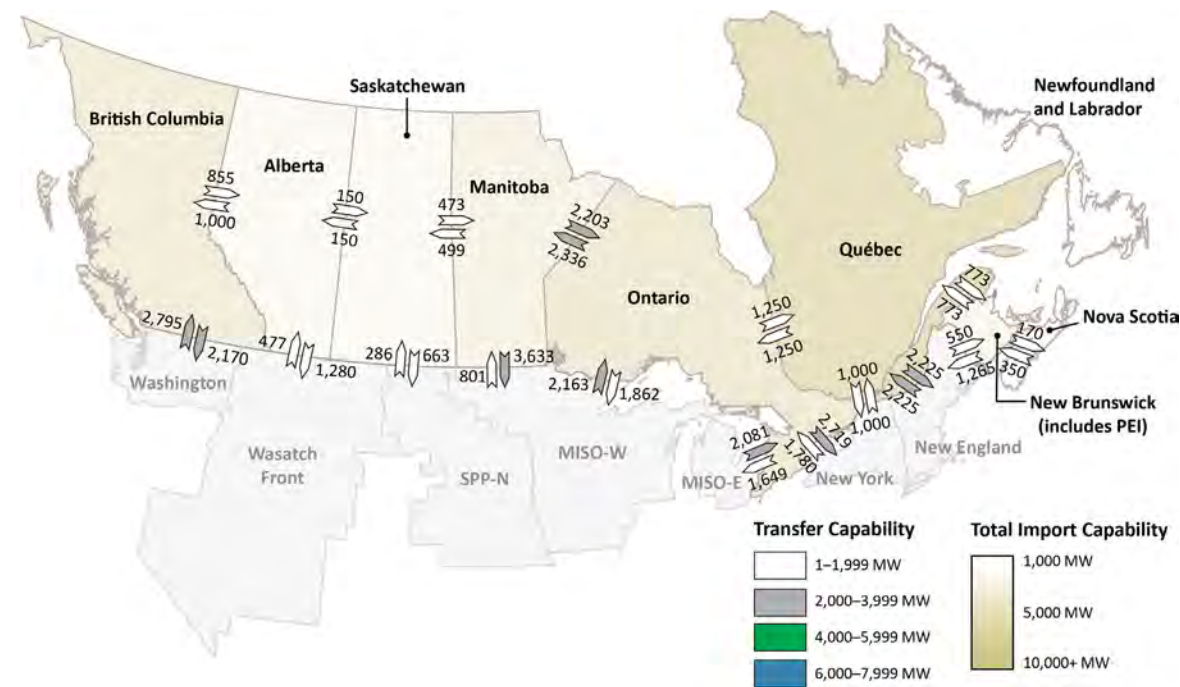


Figure 26: Transfer Capabilities (Winter)

The transfer capability results reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, which can vary significantly between seasons.

³⁴ This study did not incorporate climate change models.

Key Findings–Transfer Analysis

- Transfer capability varies seasonally and under different system conditions that limit transmission loading; it cannot be represented by a single number.
- Transfer capability is highly dependent on coordinated phase angle regulator settings, particularly in Saskatchewan, Manitoba, and Ontario.
- Prince Edward Island load impacts the transfer capability from New Brunswick to Nova Scotia.
- Transfer capability differs across Canada, with total import capability varying between 5% and 80% of peak load.
- Observed transfer capabilities are generally higher between Canada and the United States but relatively lower between provinces.
- The magnitude of transfer capability is not itself a measure of energy adequacy.
- Interregional transfer capability, as studied in this analysis, is not synonymous with path ratings.

Transfer Capability Additions

The Canadian Analysis also evaluated the future energy adequacy of the BPS if historical extreme weather conditions occurred again.³⁴ Specifically, the study applied 12 past weather years to the 2033 load and resource mix projection reported in the 2023 LTRA using the current transfer capabilities.³⁵ The study then evaluated the impact of additional transfer capability in mitigating the identified resource deficiencies during extreme events, thereby helping to improve energy adequacy. While there are several factors that Transmission Planners consider (including reliability, economics, and policy objectives) given NERC’s role, the Canadian Analysis focused solely on reliability, specifically in terms of energy adequacy and reserve optimization.

³⁵ The transfer capability analysis calculated current transfer capabilities for summer and winter based on 2024/25 projected system conditions using the area interchange method. Identified additions to transfer capability do not account for any changes to the transmission network that are planned after Winter 2024/25.

Key Findings–Energy Margin Analysis (2033)

- Canadian systems, like U.S. systems, were found to be increasingly vulnerable during extreme weather due to anticipated load increases and the changing resource mix. Transmission limitations, and potential for energy inadequacy, were identified in all 12 weather years studied. Enhancing transmission interfaces could reduce the likelihood of energy deficits during extreme conditions.
- Reliability risks are highly dependent on regional weather conditions. The import capability that could be beneficial during extreme conditions varied significantly across the country. An additional 12–14 GW of transfer capability may be an effective vehicle to strengthen energy adequacy under extreme conditions.
- More recent industry forecasts reflected in 2024 LTRA data generally result in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts. Ongoing studies will capture future changes.
- Weather-related outages were not found to be a major contributor to deficiency events, as Canadian systems are generally designed to handle extreme cold conditions. However, high winter peak loads can still challenge the available energy supply.
- Some identified transmission additions could be addressed by projects already in the planning, permitting, or construction phases. Likewise, existing system capability to switch resources or load between provinces, which was not accounted for in this study, may help reduce the identified shortfalls.
- The importance of maintaining sufficient generating resources underpins the study’s assumptions. Higher-than-expected retirements (without replacement capacity) would lead to increased energy deficiencies and potentially more transfer capability additions if surplus energy is available from neighbors.
- A broad set of solutions should be considered, including transmission, local resource, demand-side, and storage solutions. A diverse and flexible approach allows tailored solutions specific to each province’s vulnerabilities, risk tolerance, economics, and policies.

Just as in the U.S. ITCS, the Canadian Analysis found potential for energy deficiency in all 12 weather years evaluated. The results identified the potential for energy deficiency in six provinces, with a maximum resource deficiency of 10 GW in Québec based on 2023 LTRA data. A sensitivity study using more recent forecasts, based on 2024 LTRA data, generally resulted in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts.

The Canadian Analysis used these results to develop a list of additions to transfer capability from neighboring TPRs, including geographic neighbors without existing electrical connections. The analysis identified 14 GW of additional transfer capability that would improve energy adequacy under the studied extreme conditions throughout Canada. In the U.S. analysis reported last year, 35 GW of additional transfer capability was recommended across the U.S. to improve energy adequacy under extreme conditions. [Figure 27](#) shows the existing and potential new interfaces for Canadian TPRs where beneficial additional transfer capability is identified.

Transfer capability additions are based on 2033 resource mix and other study assumptions

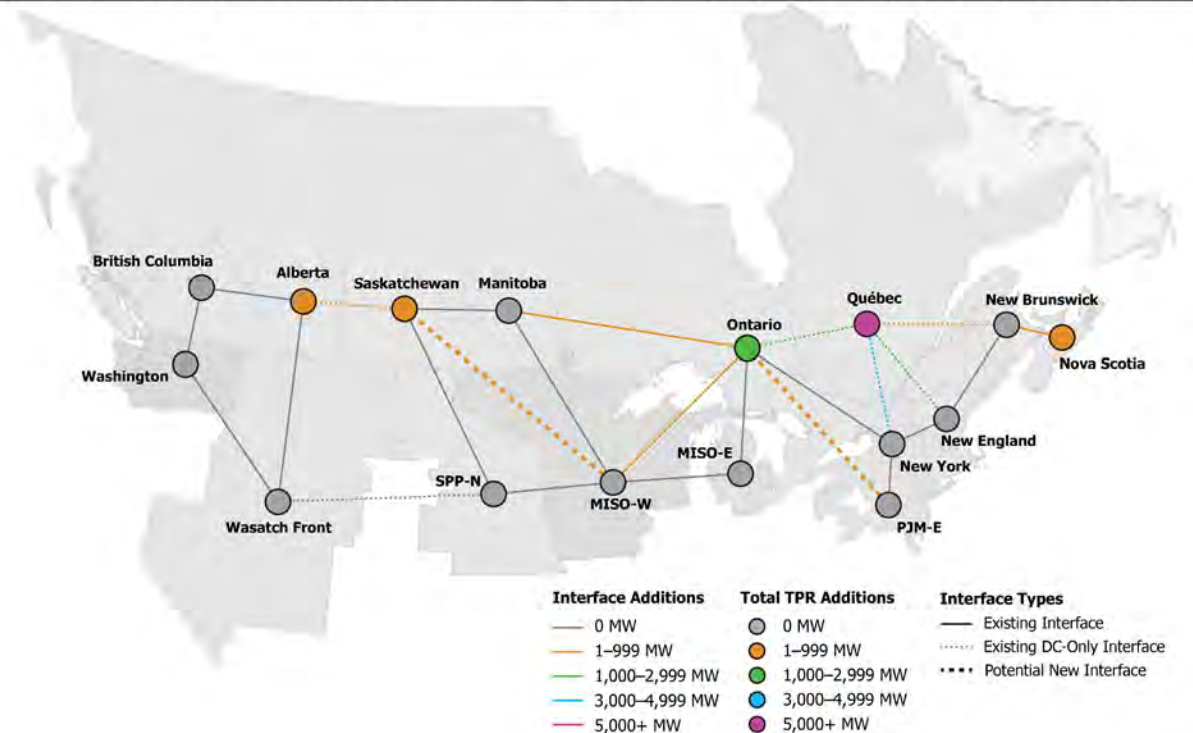
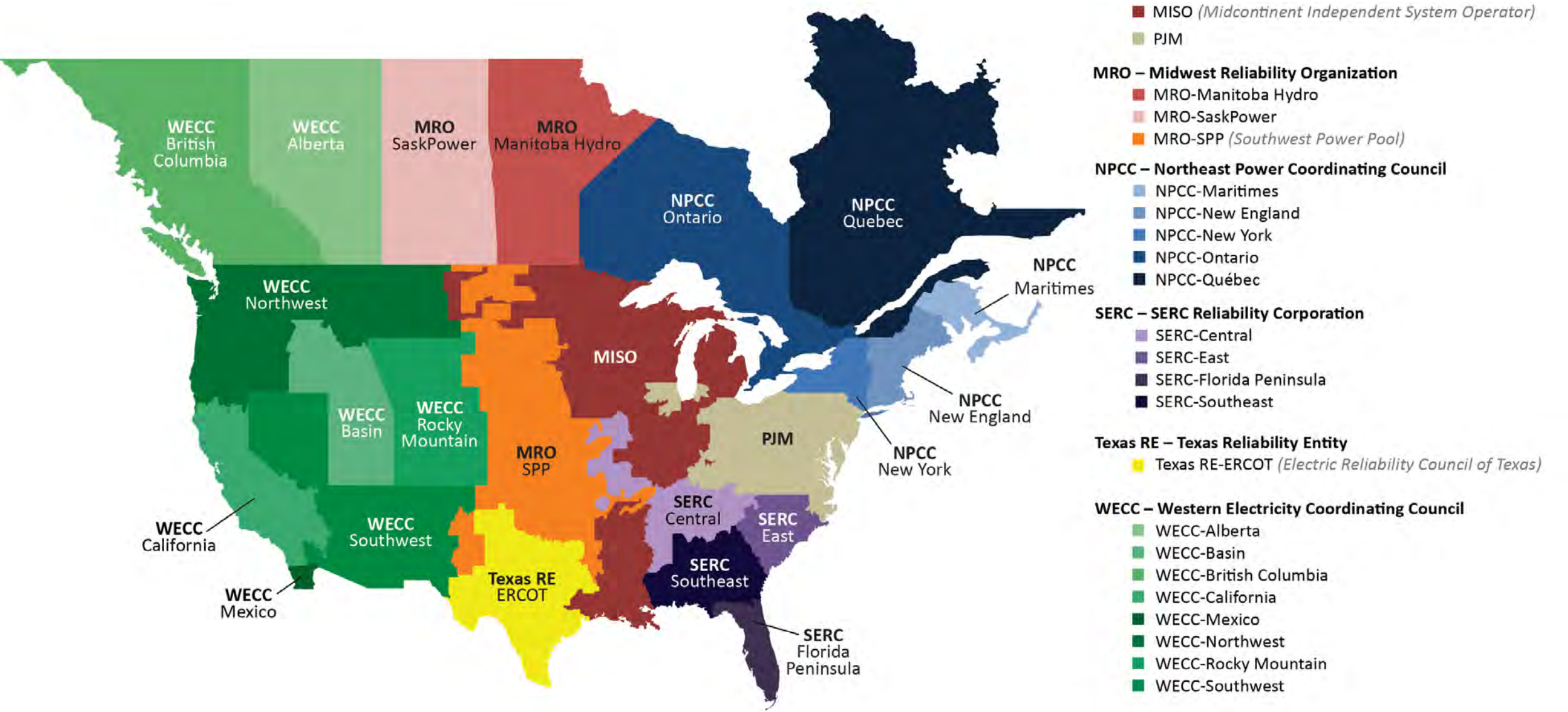


Figure 27: Transfer Capability Additions

Regional Assessments Dashboards

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee, at the direction of NERC’s RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



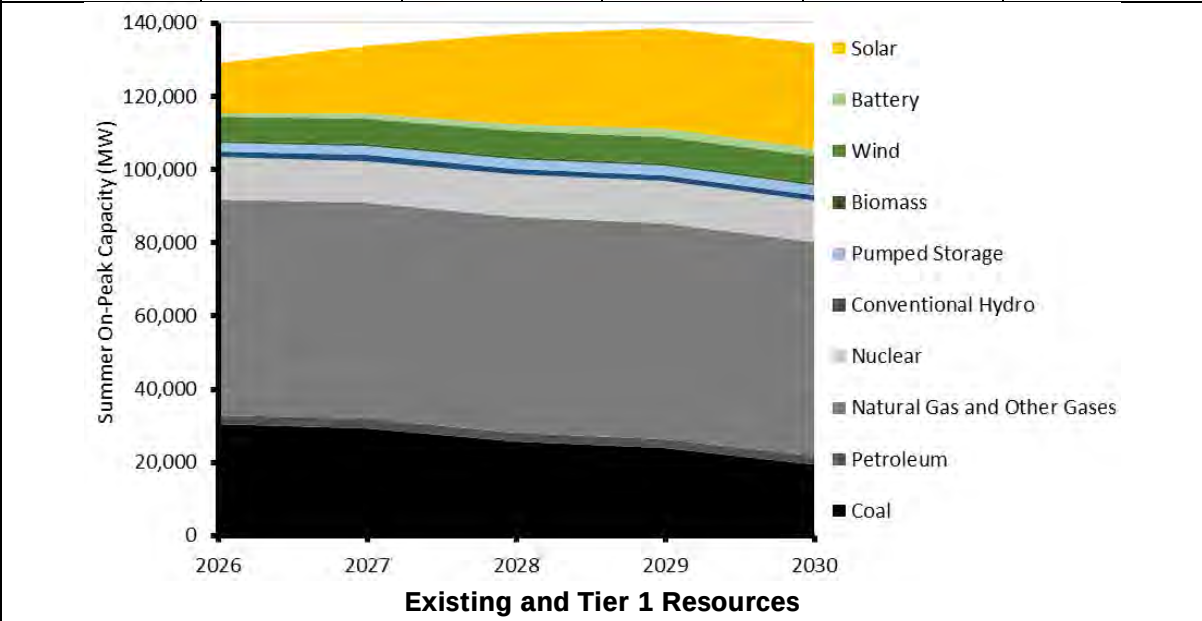
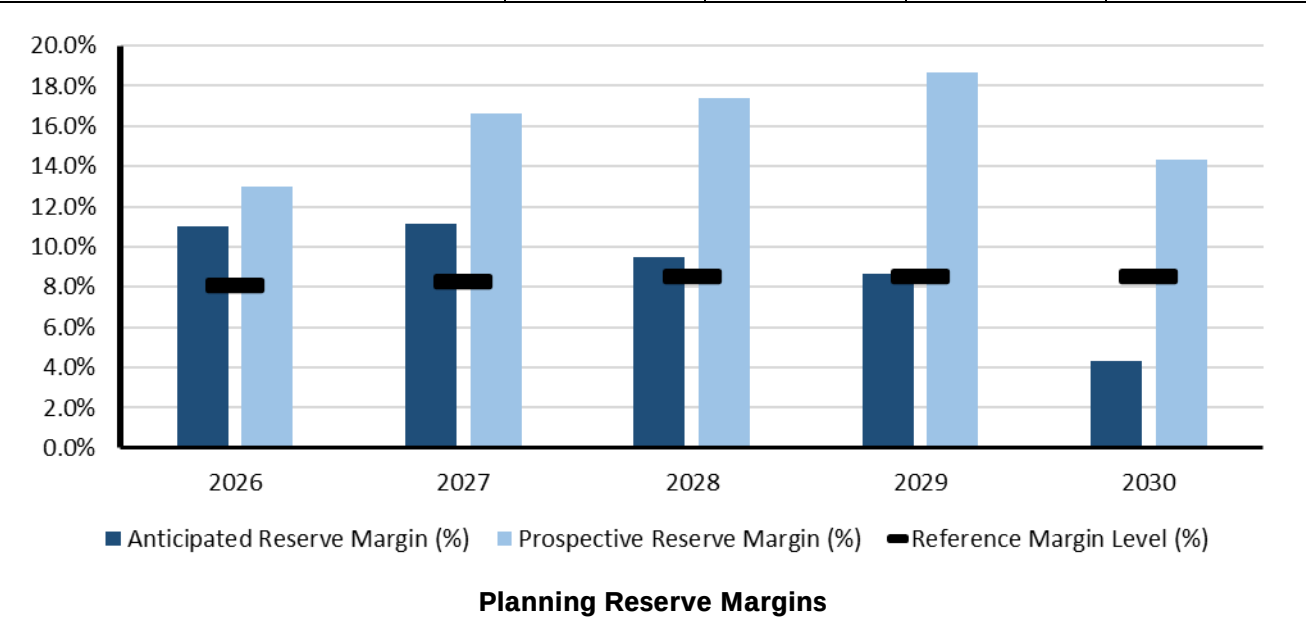


MISO

The Midcontinent Independent System Operator, Inc. ([MISO](#)) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations and energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 local BAs and more than 550 market participants. MISO operates one of the world’s largest organized electricity markets, with its members operating a system that consists of over 79,000 miles of transmission lines and approximately 1,979 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO’s footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC’s reliability assessments.

Demand, Resources, and Reserve Margins (Summer)

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	127,071	131,107	135,998	138,286	139,631	140,959	142,003	142,789	143,754	143,754
Demand Response	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280
Net Internal Demand	118,791	122,827	127,718	130,006	131,351	132,679	133,723	134,509	135,474	135,474
Additions: Tier 1	5,576	13,339	21,350	24,631	26,027	26,320	26,366	26,366	26,366	26,366
Additions: Tier 2	2,403	6,723	10,072	13,056	13,116	13,260	13,364	13,466	13,466	13,466
Additions: Tier 3	1,632	4,459	9,395	14,474	19,823	23,820	27,983	27,858	27,915	28,077
Net Firm Capacity Transfers	2,809	2,661	2,509	2,509	2,419	2,419	2,419	2,419	2,419	2,419
Existing-Certain and Net Firm Transfers	126,263	123,205	118,481	116,593	110,996	108,686	106,448	106,568	106,553	106,553
Anticipated Reserve Margin (%)	11.0%	11.2%	9.5%	8.6%	4.3%	1.8%	-0.7%	-1.2%	-1.9%	-1.9%
Prospective Reserve Margin (%)	13.0%	16.6%	17.4%	18.7%	14.3%	11.7%	9.3%	8.8%	8.1%	8.1%
Reference Margin Level (%)	8.1%	8.3%	8.5%	8.5%	8.5%	8.6%	8.7%	8.8%	8.9%	8.9%



MISO Highlights

- For Summer 2026, MISO projects a prospective resource surplus ranging from 3.4 to 5.8 GW, but, if historical rates of resource additions continue, a deficit of resources beginning in Summer 2030 may be realized. The recently approved ERAS is expected to result in a considerable amount of new resource additions to the MISO system by 2029, which was not included in this year’s assessment due to the timing of FERC approval. As of December 2025, around 30 GW of new capacity is being studied through the ERAS process.
- MISO forecasts that the coincident total internal demand will peak at 127.1 GW during the 2026 Summer season and will grow to 143.7 GW by 2035. The largest contributor to this demand growth is data center additions.
- MISO’s accredited thermal capacity has decreased by 8.8 GW, primarily driven by reductions in accredited capacity of existing resources, and accredited non-thermal capacity has increased by 5.7 GW since last year, primarily driven by solar additions.
- In July 2025, MISO had more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that were projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity.
- Currently, MISO has surplus transfer capacity within its subregions, but transfers between subregions have been historically constrained by a transmission limitation between the two subregions. MISO members plan to invest \$30 billion to install nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV transmission lines to address local, regional, and interregional transmission needs.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	30,442	29,376	25,620	23,780	19,384
Petroleum	2,551	2,551	2,551	2,551	2,428
Natural Gas	58,748	58,892	58,984	59,099	58,262
Biomass	585	580	516	515	512
Solar	13,586	18,496	24,792	27,499	28,629
Wind	6,576	6,757	7,139	7,258	7,379
Conventional Hydro	1,521	1,523	1,524	1,524	1,524
Pumped Storage	2,608	2,608	2,608	2,608	2,608
Nuclear	11,571	11,571	11,571	11,571	11,571
Other	68	68	68	68	63
Battery	774	1,462	1,950	2,243	2,243
Total MW	129,031	133,883	137,322	138,715	134,604

MISO Assessment

MISO’s guiding principles for its planning process include six key objectives: reliability and resilience; economic efficiency/lowest total electric system cost; support of federal, state, and local energy policy and member goals for their respective resource mixes; appropriate cost allocation for transfer-enabling assets; analysis of an appropriate range of system scenarios and dissemination of results to relevant decisionmakers; and coordinated planning processes among neighbors to eliminate barriers to reliable and efficient operations. See MISO’s [Statement of Guiding Principles](#) for more information.

Planning Reserve Margins

Every year, MISO coordinates with its stakeholders to calculate the minimum amount of capacity above coincident peak demand required such that the LOLE equals one-day-in-10 years, or 0.1 days per year. For the MISO-wide analysis, generating units were modeled as part of their appropriate local resource zone as a subset of a larger MISO system. The MISO system was modeled with no internal transmission limitations between zones. To meet the LOLE reliability criteria, capacity is either added or removed from the MISO system within the model. The minimum amount of capacity above the MISO system coincident peak demand forecast required to meet the LOLE reliability criteria was used to establish seasonal Planning Reserve Margin (PRM) values. This minimum PRM is based on a probabilistic analysis and is expressed for each season as an unforced capacity (UCAP) requirement based on the modeled availability of resources in the MISO system. UCAP represents an adjustment from installed capacity (ICAP) that accounts for a generator’s equivalent forced outage rate demand, a measure of the probability that a generating unit will not be available due to forced outages, which MISO further adjusts to exclude events outside management control.

MISO’s [LOLE Study for PY 2025–2026](#) estimated the minimum seasonal PRM values (in UCAP) as follows:

- Summer 2026: 8.1%
- Fall 2026: 14.9%
- Winter 2026-2027: 19.1%
- Spring 2027: 26.2%

The study that produced these PRM values included a probabilistic risk modeling and power flow transfer analysis to also determine zonal local reliability requirements (LRR), zonal import ability (ZIA), zonal export ability (ZEA), capacity import limits (CIL), and capacity export limits (CEL). A software program called Strategic Energy & Risk Valuation Model (SERVM) was used to calculate LOLE for the applicable planning year.

The results of the LOLE Study for PY2 5-26 serve as inputs to the MISO Planning Resource Auction (PRA). The computed PRMs are used in area adequacy assessments unless an area includes an entity that falls under a state regulatory body’s purview, in which case a state-mandated PRM may be used in MISO’s analysis in place of the computed PRM.

In most of the MISO footprint, LSEs with oversight by the applicable state or local regulators are responsible for resource adequacy. Every year, MISO collaborates with the Organization of MISO States (OMS) to survey its members about their plans to maintain resource adequacy in the coming years. The OMS-MISO survey provides a resource adequacy view for the MISO region over a five-year horizon based on the latest information available at the time of survey. The [2025 OMS-MISO Survey](#) indicated that LSEs are expected to have adequate resources to meet load reserve requirements; however, various projected capacity scenarios and large spot-load additions highlight the increasing uncertainty and evolving risk.

For Summer 2026, MISO projects a prospective surplus ranging from 3.4 to 5.8 GW. Moving beyond the short term, if historical rates of resource additions continue in MISO as reflected in the anticipated resources projection for the NERC LTRA, a deficit of resources beginning in summer 2030 may be realized. This potential shortage is due to accelerated load growth and inadequate build rates for new resources. Interconnection of additional identified resources in Tier 2 and potential resources in Tier 3 could present an opportunity to retain a resource surplus through the entirety of the LTRA study time frame.

In anticipation of resource shortages beginning in Summer 2030, MISO has initiated the following processes and reforms:

1. Implement the interim [ERAS](#) process to facilitate the accelerated rollout of new resources to meet increased demand growth. This process has yielded nearly 30 GW of potential new capacity as of December 2025.
2. Move to a direct loss of load (DLOL) marginal accreditation model for the 2028–2029 planning year, which is intended to better reflect the true value of the next megawatt of resources during critical hours
3. Enhance resource adequacy risk assessment and communication like aligning solar representations between the PRA and LOLE model, properly represent non-firm imports between neighboring regions, and investigate the relationship between solar and battery installations and how their capacity might impact one another.
4. Reduce queue cycle times through automation

- 5. Establish a more robust DR and emergency resource process moving forward to ensure non-market units are being appropriately accredited.
- 6. Enhance allocation of resource adequacy requirements.

Energy Risk

MISO uses a seasonal PRA and conducts seasonal resource assessments to evaluate generation availability, outage rates, and forecasted load. Based on outcomes of these processes, MISO has also initiated a change to its capacity market construct, in part, to ensure energy adequacy by evaluating how classes of resources and each individual resource help serve load during periods of the year that demonstrate the most reliability risk to the MISO system.

Beyond the probabilistic energy risk assessments associated with MISO’s LOLE Study for PY 25–26, MISO has also performed additional assessments for [renewable integration](#) and [regional resource evolution](#) that touch on the topic of energy risk but are not a formal part of MISO’s resource adequacy and resource planning processes.

ProbA Results

The results of the ProbA simulations show normal risk for the MISO system in study year 2027 and more pronounced, elevated risk in study year 2029 wherein MISO assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year’s analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and have the ability to address uncertainties associated with these three variables.

MISO initiatives like ERAS and joint collaborative efforts between MISO, its membership, regulators, and neighboring regions will be critical to ensuring resource adequacy in the coming years.

While overall installed nameplate capacity across the system is expected to increase in the coming years, system risk can be expected as the aging thermal fleet in MISO’s system continues to retire and is replaced with more intermittent, less available generation. Significant demand growth, in part due to large data center loads, has been forecasted by MISO’s LSEs. It is important to note that a substantial number of large-load customers continue to evaluate their options for participation in the markets, including the potential to participate as DR resources during emergency conditions. The construction delays for new resources due to supply chain and other issues, as well as the ongoing evaluation of large-load customers, contribute to continued uncertainty regarding both overall resource availability and the prospective participation of large loads as DR resources in the

markets. This substantiates that MISO, its membership, and regulators must continue to monitor retirements and large-load additions and increase resource additions to ensure future resource adequacy.

The ProbA simulations for study year 2029 resulted LOLE of 2.4 days in 1 year compared to the target of 0.1 day in 1 year. The primary drivers for the expected risks in 2029 include the following:

- Load growth increases: Peak demand for winter is expected to grow considerably—approximately 9–10 GW in 2029.
- Nameplate capacity changes: To align with MISO’s annual LOLE studies and proactively send the right signals, member-submitted low certainty resources from the most recent OMS-MISO Survey were assumed to be unavailable in study year and amounted to approximately 14 GW of additional unconfirmed retirements by Winter 2029.
- Summer risk shifts to later in the day: An increased reliance on solar generation as the resource mix evolves results in summer risk appearing as solar generation ramps down.
- In Winter 2029, risk is emerging in morning and twilight hours: Shifting winter risk is driven by a combination of increased reliance on solar generation, an increase in member-submitted load forecasts, elevated thermal forced outages induced by extreme cold temperatures, and a larger generation deficit than in prior years.

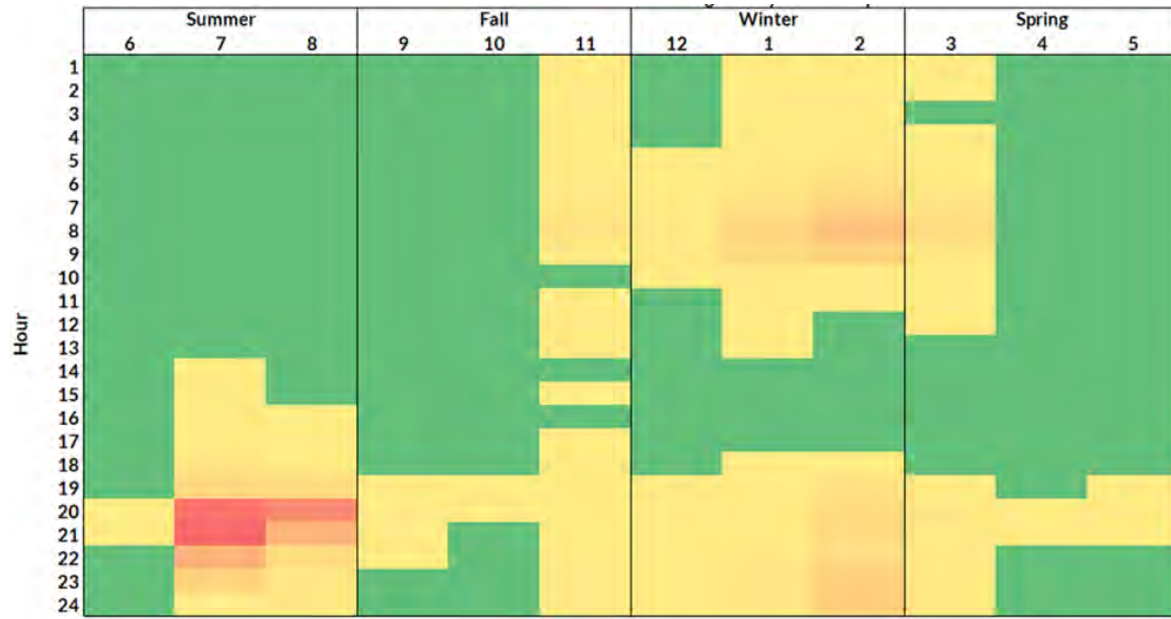
Base-Case Summary of Results			
	2026*	2027	2029**
EUE (MWh)	0	797	31,654
NEUE (ppm)	0	1.13	42.4
LOLH (hours per Year)	0	0.23	6.61

*Provides the 2024 ProbA Results for Comparison
**The 2029 ProbA study assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year’s analysis.

The following EUE heat maps show the distribution of unserved energy events from the probA simulations across hours and seasons. Green cells indicate no unserved energy events, while yellow and red cells indicate increasing numbers of simulations with unserved energy.



2027-2028 ProbA Heat Map



2029-2030 ProbA Heat Map

Demand

LSEs within MISO’s footprint report two sets of seasonal peak demand projections, coincident with the entire MISO system and coincident with their applicable local resource zone. LSEs also submit their non-coincident peak demand projections for the next 10 years, monthly for the first two years and seasonally for the remaining eight years. Coincident peak demand forecasts are based on factors including average historical weather conditions, economic conditions, and expected demand changes. For the 2025 LTRA, MISO used its LSE demand submissions to create non-coincident and coincident peak demand projections on a regional basis by summing the annual peak demand forecasts for the individual LSEs in the larger region of study. In MISO’s normal process, the coincident peak demand forecast is used to determine each LSE’s PRM requirement.

MISO forecasts the coincident total internal demand to peak at 127,071 MW during the 2026 Summer season. Since the 2024 LTRA, MISO has increased its 10-year forecast peak demand from 132 GW to 143.7 GW. This rate of increase is expected to continue.

The largest increases in demand in the MISO footprint are related to data centers. These large load additions are projected to result in significant increases in the demand for energy in all hours and would not conform to typical residential or industrial load patterns. In total, MISO projects approximately 6 GW of data center load additions by 2027, accumulating to 14 GW by 2030, and 18 GW by 2035. MISO published [a Long-Term Load Forecast white paper](#) in December 2024. This white paper comes to similar conclusions around the load growth rate based upon member submissions by way of the MOD-031/FERC 714 data pathway.

Demand-Side Management

A combination of peak demand hour performance, forecasting, and baseline scenarios help MISO to determine the amount of DR capacity available during peak demand hours. DR programs continue to play a significant role in providing capacity for MISO. For the 2025/26 planning year, DR is steady around 9 GW in the summer and 8 GW in the winter and is projected to remain constant during the LTRA study horizon. MISO’s latest reforms for demand-side resources focus on accrediting such resources based on their availability and performance during the highest-risk hours (in and near emergency conditions).

Distributed Energy Resources

Behind-the-meter-generation (BTMG) resources contribute about 4.4 GW of capacity across the study horizon, of which approximately 1.3 GW are distributed photovoltaics. MISO’s transition to seasonal auctions highlights the variability of DERs across the four seasons, and it is working with stakeholders to derive adequate methods of aggregating, reporting and allowing DER participation in MISO markets.

Generation

Because of the size of MISO’s interconnection queue, in the 2025 NERC LTRA, generation in the queue is multiplied by a reduction factor based on the study phase and likelihood of that resource coming on-line and the timing of those additions. MISO notes that the recent [2025 OMS-MISO survey](#) used a slightly different resource addition cadence than what is reported for the LTRA that factors in both planned utility/member-specific generation addition rates and historical addition cadences. Specifically, the LTRA’s existing resource capacities come directly from the 2025–2026 MISO Planning Resource Auction (PRA), based on the amount of confirmed seasonal accredited capacity. Tier 1 resources describe the expected integration rate of currently signed generator interconnection agreements (GIA) over a three-year delay ramp to represent the fact that many GIAs experience delays on their path to installation in MISO. Tier 2 resources are based on active replacement projects and Phase 3 GIAs. Tier 3 resources are based on a 15% completion rate of all non-signed GIAs with the three-year delay schedule in line with Tier 1 resources.

As of December 2025, MISO had more than 70 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. Since the 2024 NERC LTRA, MISO has observed an 8.8 GW reduction in thermal accredited capacity, driven primarily by aging existing facilities, unit suspensions, and retirements. However, suspensions and retirements in MISO have recently been followed by replacement facilities that re-utilize the interconnection service with new units. More than 75% of the units pursuing cessation in MISO are also pursuing replacement projects. Non-thermal accreditation has increased by 5.7 GW since the 2024 NERC LTRA report.

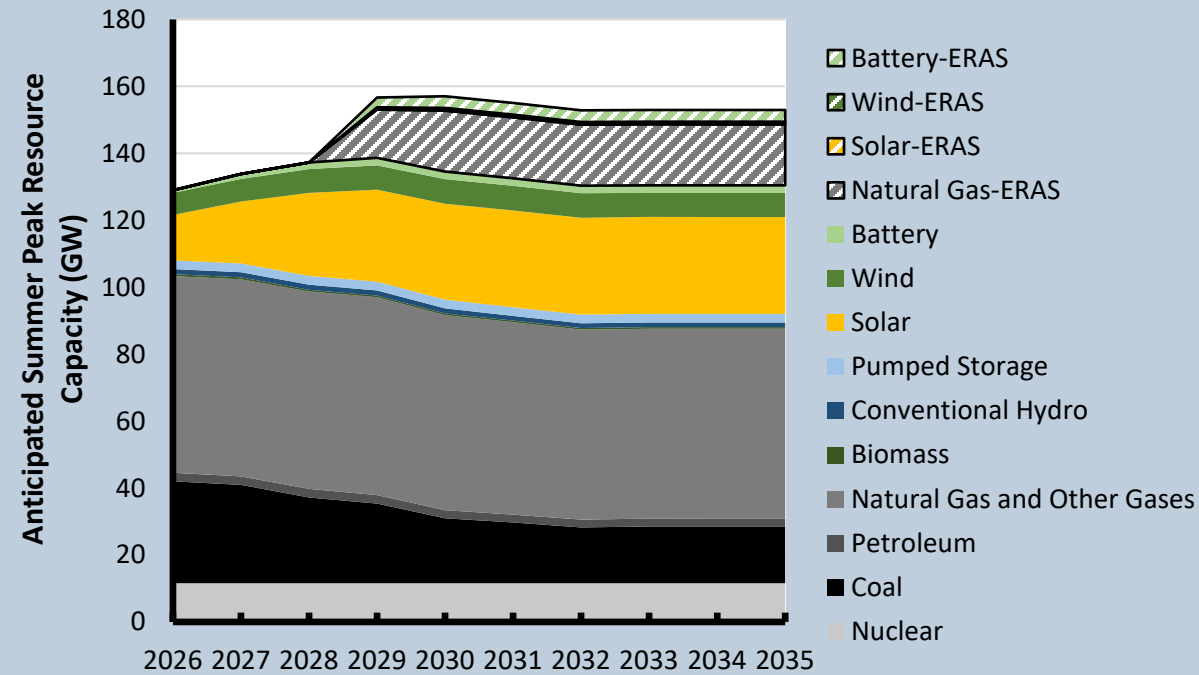
MISO’s accreditation of battery resources is tied to the mandatory 4-hour energy offer window, resulting in most storage resources pursuing the ratio of 1 MW/h for 4 hours. Battery storage resources receive a 95% class-wide accreditation (relative to nameplate capacity) in the MISO PRA and NERC LTRA for their first year in operation in lieu of historical output data. Wind ELCC analyses have been performed for all seasons. Wind capacity is given the following seasonal accreditations: Summer: 20.8%; Fall: 30.7%; Winter: 29.0%; Spring: 25.3%. The effective capacity for existing solar resources is based on historical performance during typical seasonal peak hours. New solar resources get 50% accreditation relative to nameplate capacity in the summer, fall, and spring seasons and 5% in the winter season. Hydro resources accredited capacity is calculated based on historical performance during seasonal peak hours.

Energy Storage

MISO is experiencing increased interest by members for battery energy storage, with more than 500 MW currently on-line, and queue projects identifying more than 100 GW of battery or hybrid fuel type projects. MISO’s anticipated installations include an addition of more than 2.4 GW by Summer 2030

and a prospective battery fleet of nearly 7 GW by 2035. The primary expected usage for batteries is for reliability, providing significant capacity capability with the variable nature of MISO’s growing solar and wind fleet. MISO performs risk modeling with advanced storage representations to ensure that battery capacity is characterized appropriately.

The timing of FERC’s approval of MISO’s ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the 2025 LTRA. ERAS is already expected to result in considerable new resource additions to the MISO system in the near term. The additional summer on-peak capacity from the ERAS program is expected to grow to over 20 GW by Summer 2030. These expedited resource additions are expected to reduce the shortfall risk identified in this year’s ProbA. Furthermore, the timing of the ERAS additions would mitigate an identified winter ARM shortfall if the approximately 8.6 GW of winter on-peak capacity anticipated by 2028–29 reaches operation as projected. The latest ERAS projects, along with current load forecasts and resource projections as of July 2026, will be included in the input data for the 2026 LTRA and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.



The Potential Effect of MISO’s ERAS Process on Anticipated Summer Capacity

Energy Transfers

In the PRA, MISO accredits several power purchase agreements known as diversity contracts between Manitoba Hydro and MISO internal generation owners, wherein energy flows from Manitoba to the MISO system in the summer when Manitoba has excess hydro power vice-versa in the winter. Currently, MISO has surplus capacity in both the MISO North/Central and MISO South subregions, but imports and exports between them have been historically constrained by a transmission limitation.

A key input to MISO’s probabilistic risk modeling that determines the system-wide seasonal PRM values is how much non-firm energy support MISO can reasonably expect from neighboring external areas. Every year, MISO performs an analysis of recent year trends in seasonal non-firm energy support to develop a range for each season that the probabilistic model will randomly draw from mid-simulation. Additionally, MISO found this year that there was not a significant difference in the amount of non-firm energy support MISO received from its neighbors during hours and days with tight operating margins when compared to normal operating conditions.

Transmission

MISO, in collaboration with its transmission-owning members and stakeholders, performs annual reliability assessments to identify transmission infrastructure upgrades needed to ensure system reliability. Many factors are considered during MISO’s transmission expansion planning process, including urgency of need, suitability of alternatives to address identified issues, cost effectiveness, performance of alternatives, development time frame, right-of-way or substation impacts, expandability, and operational flexibility. To learn more about MISO’s transmission expansion plan, see information and reports posted on MISO’s [MTEP](#) page.

MISO has 488 transmission projects totaling \$30 billion planned across [MTEP24](#), its [Long Range Transmission Planning \(LRTP\)](#) Tranche 2.1, and the [SPP-MISO Joint Targeted Interconnection Queue \(JTIQ\)](#). In total, these three programs include nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV

transmission lines in their project portfolios. These projects aim to address local, regional, and interregional needs across the area’s large geographic footprint by enabling reliability in response to accelerating load growth. In fact, most of the demand increases reported by LSEs in the MISO footprint can be tracked to transmission projects either in the Expedited Project Review (EPR) or normal MTEP project pathway. Specifically, MISO’s Tranche 2.1 Portfolio seeks to establish a transmission system backbone for the whole MISO system, and the JTIQ portfolio is being undertaken with the potential to unlock approximately 28 GW of generator interconnections, eliminating barriers to new capacity at the SPP-MISO seam.

As of December 1, 2025, MISO identified 63 projects comprising 12.8 GW of additional load through the EPR process.

Reliability Issues

Load growth and additions are increasing. A spike in large, single-site load additions from manufacturing resurgence and incremental load growth from electric vehicles and other electrification trends pose new challenges for the grid. Continued high numbers of MTEP projects submitted through the expedited project review request, which are urgent projects that cannot wait for the next full MTEP cycle to proceed, are evidence of this faster paced load growth and additions.

Maintaining resource capacity margins will require accelerated resource additions to outpace retirements and the forecasted load growth. Recent reforms have helped to reduce the volume of requests and to process them more efficiently. As of December 1st, 2025, MISO has 1,127 Active interconnection queue projects that total 215 GW of nameplate capacity. This is in addition to the 444 projects and 70 GW of signed GIAs.

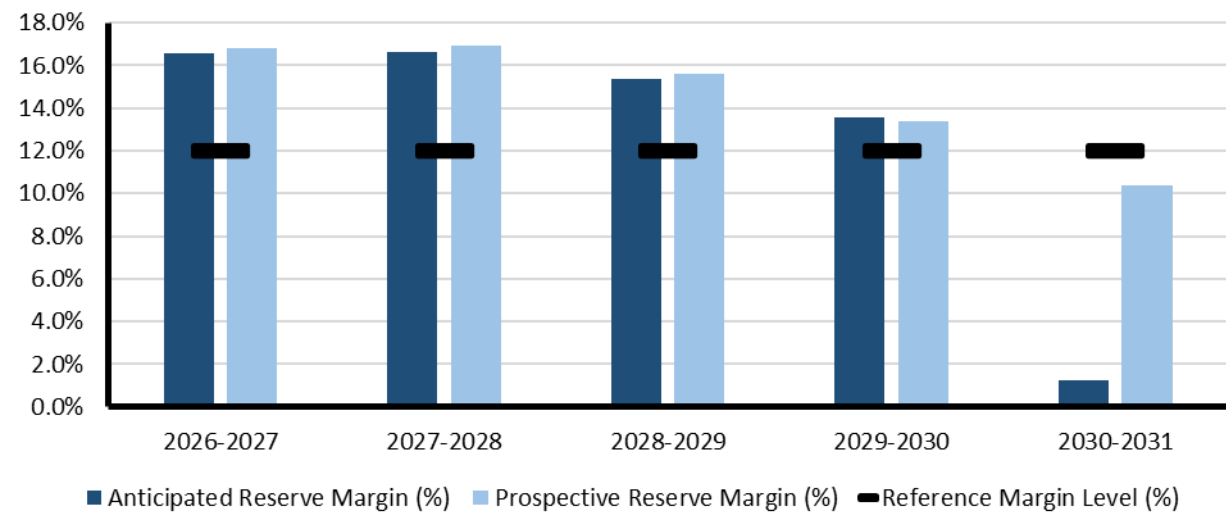


MRO-Manitoba Hydro

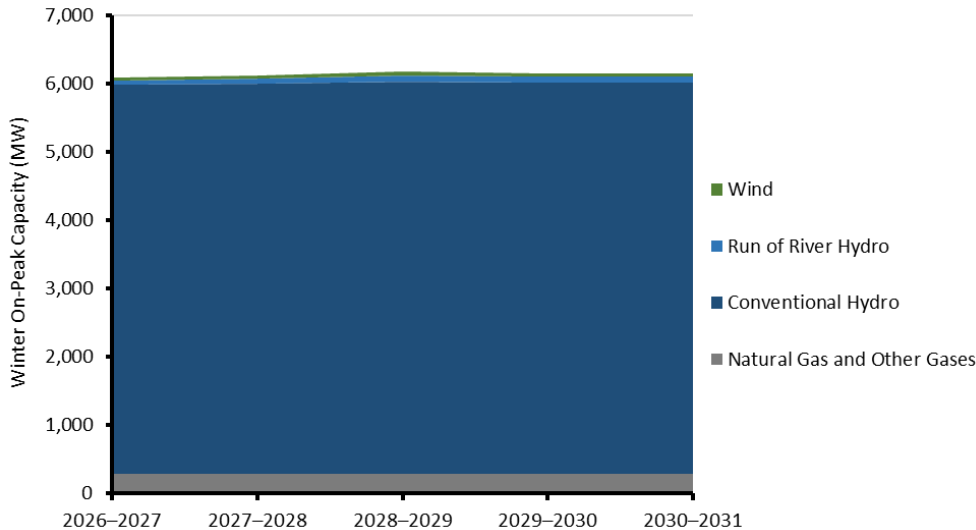
Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in 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 PC and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	5,002	5,041	5,081	5,137	5,374	5,412	5,447	5,507	5,580	5,655
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	5,002	5,041	5,081	5,137	5,374	5,412	5,447	5,507	5,580	5,655
Additions: Tier 1	36	50	63	63	63	63	63	63	63	63
Additions: Tier 2	0	0	0	0	500	500	500	500	500	500
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-113	-93	-167	-172	-565	-565	-565	-565	-565	-315
Existing-Certain and Net Firm Transfers	5,794	5,831	5,799	5,770	5,377	5,377	5,377	5,377	5,377	5,627
Anticipated Reserve Margin (%)	16.6%	16.7%	15.4%	13.6%	1.2%	0.5%	-0.1%	-1.2%	-2.5%	0.6%
Prospective Reserve Margin (%)	16.8%	16.9%	15.6%	13.4%	10.4%	9.6%	8.9%	7.7%	6.3%	9.3%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-Manitoba Hydro Highlights

- Manitoba projects a shortfall in anticipated resources starting in the winter of 2030–2031.
- The demand is projected to grow over 13% through the assessment period.
- The Province of Manitoba paused cryptocurrency interconnection requests until April 2026 to prepare a long-term solution to limit reliability impacts to the system.³⁶

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	278	278	278	278	278
Wind	52	52	52	52	52
Conventional Hydro	5,705	5,723	5,758	5,735	5,735
Run of River Hydro	59	71	90	90	90
Total MW	6,094	6,124	6,179	6,155	6,155

³⁶ [Province directs Manitoba Hydro to continue pause on new cryptocurrency connections](#)

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The ARM for the summer season does not fall below the RML of 12% during the 10-year assessment period. The ARM for the winter season falls below the RML of 12% beginning in Winter 2030–2031 due to a combination load growth and reduced resources due to an ending of winter capacity import contracts (“diversity capacity”) in 2030, as well as an assumed reduction of the Curtailable Rate load management program.

Demand

Manitoba Hydro is anticipating load growth of 1.5% (net of demand side management) over the assessment period. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management

Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five-minutes notice. The program is intended for peak load management. In addition, one product of the Curtailable Rate Program provides 50 MW of contingency reserves, also on five-minutes notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Manitoba Hydro is in the process of developing a new industrial rate pilot, with the combined goal of reducing winter peak and providing additional rate options for customers that both assist customer profitability and help keep costs low for all Manitobans. The rate pilot is being developed to leverage existing technology and programming with the intent of introducing the program on a pilot basis.

Manitoba Hydro, in collaboration with Efficiency Manitoba, is looking to develop a DR pilot program aimed initially at targeting smart thermostats with the focus on reducing Manitoba’s winter peak. The pilot program is targeting to launch for the winter of 2025.

Energy Risk

As the operator of a predominantly hydro system, weekly at a minimum, Manitoba Hydro performs an all-hours season-ahead energy adequacy analysis as required to manage near-term to seasonal-ahead reservoir energy storage while meeting system demands. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements that would be required to maintain Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to fall at or very near the peak demand hours.

Probabilistic Assessment (ProbA)

Every year, Manitoba Hydro prepares a probabilistic assessment for the Manitoba system, most recently in 2024. The 2024 probabilistic assessment was supportive of a 12% PRM for the Manitoba system being sufficient to provide an LOLE of less than 0.1 days per year under the study assumptions. Results of the 2025 ProbA prepared for the LTRA are as follows.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	4	3	6
NEUE (ppm)	0.17	0.12	0.23
LOLH (hours per Year)	0.05	0.03	0.06
* Provides the 2024 ProbA Results for Comparison			

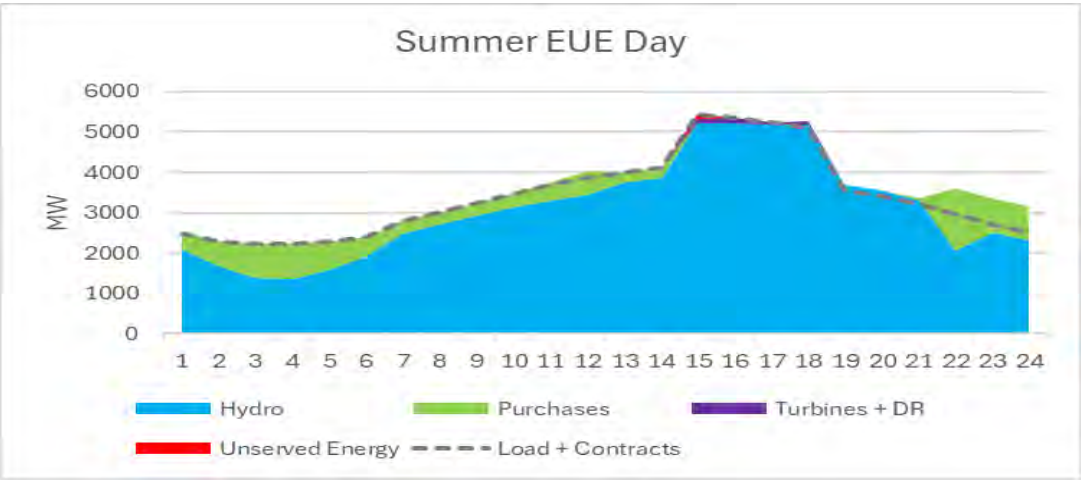
There were no appreciable Manitoba loss-of-load events seen in winter or in the summer for 37 of the 44 weather/ flow years studied. Manitoba loss-of-load events that were seen in summer occurred during the lowest flow years with upwards of 80% of the risk of loss of load occurring in the two worst flow years (1988 and 2003) of the 44 years studied. The Manitoba loss-of-load events that were seen in summer were driven by very low hydro flow conditions combined with both very high summer loads in Manitoba and very high summer loads on the MISO system.

The annual EUE heat map for 2029 is provided below.

2029 EUE Heat Map



A sample summer EUE day with very high loads on the Manitoba and MISO systems during extreme drought is shown in the illustration below. For much of the day, Manitoba is a net importer of power.



Distributed Energy Resources

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

Generation

Under normal water conditions, over 95% of the generation in Manitoba Hydro’s system is from renewable energy—primarily hydro generation and wind generation. A Tier 1 project to replace eight older and smaller hydro units is in progress for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation.

On February 25, 2025, Manitoba Hydro filed with its regulator the preliminary estimate for a 500 MW gas capacity resource entering service in 2030. While not yet approved, this proposed plant was included as Tier 2 capacity resource. Manitoba is not currently experiencing the large additions of wind and solar resources seen in other regions, and hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated over the next five years. Manitoba Hydro is working on an [Integrated Resource Plan](#) that will support future investment decisions. The Government of Canada is further regulating carbon dioxide emissions from the electric generation sector, finalizing the Clean Electricity Regulations in December 2024. These regulations begin to restrict fossil fuel generation in 2035 and direct Canadian electric generation to achieve net-zero greenhouse gas emissions by 2050. Manitoba Hydro does not anticipate that meeting the Clean Electricity will have a negative impact on system reliability or modify the operation of Manitoba’s electricity system. The Province of Manitoba provided energy policy direction with the publication of the Affordable Energy Plan in September 2024. Energy conservation, wind generation, and dispatchable back-up generation, such as natural gas combustion turbines, form the basis of the plan. Manitoba Hydro’s forthcoming 2025 Integrated Resource Plan will be consistent with the policy direction.

Energy Storage

Additions of battery energy storage system (BESS) resources in the next 10 years are not anticipated at this time. The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources on-line are hydro generation resources, which therefore serve most operational, reliability, and economic functions. In the longer term, there may be a role for energy storage resources in Manitoba in areas that may become transmission constrained. Preliminary long-term studies of a modest amount of energy storage resources have not identified

operational challenges and have not required modification to planning assumptions since the 2024 LTRA.

Energy Transfers

The Manitoba Hydro system is winter-peaking and is interconnected to the MISO Zone 1 Local Resource zone (which includes Minnesota and North Dakota), which as a whole is summer-peaking. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts, but only if the following conditions occur simultaneously: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. In the unlikely event of such a situation, Manitoba Hydro would implement plans developed in accordance with emergency operating procedures for capacity and energy emergencies, including calling on emergency energy from Adjacent Balancing Authority Coordination Agreements, if available. Transmission planning studies consider maximum firm winter import and N-1 and N-2 contingencies. The completion of the Manitoba–Minnesota 500 kV transmission line on June 1, 2020, increased import capability from 700 MW to 1,400 MW and firm export capability from 2,100 MW to 2,983 MW. This new 500 kV line also improved the resilience of the network in the event of transmission contingencies. The 500 kV line is equipped with single pole trip and reclose capability, which results in only one phase being out for one second during common single-phase faults.

The expiration of existing winter capacity import contracts (“diversity capacity”) in 2030 is contributing to overall lower firm resources from winter 2030–2031 through the remainder of the assessment period.

Transmission

Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue, which is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end-of-life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

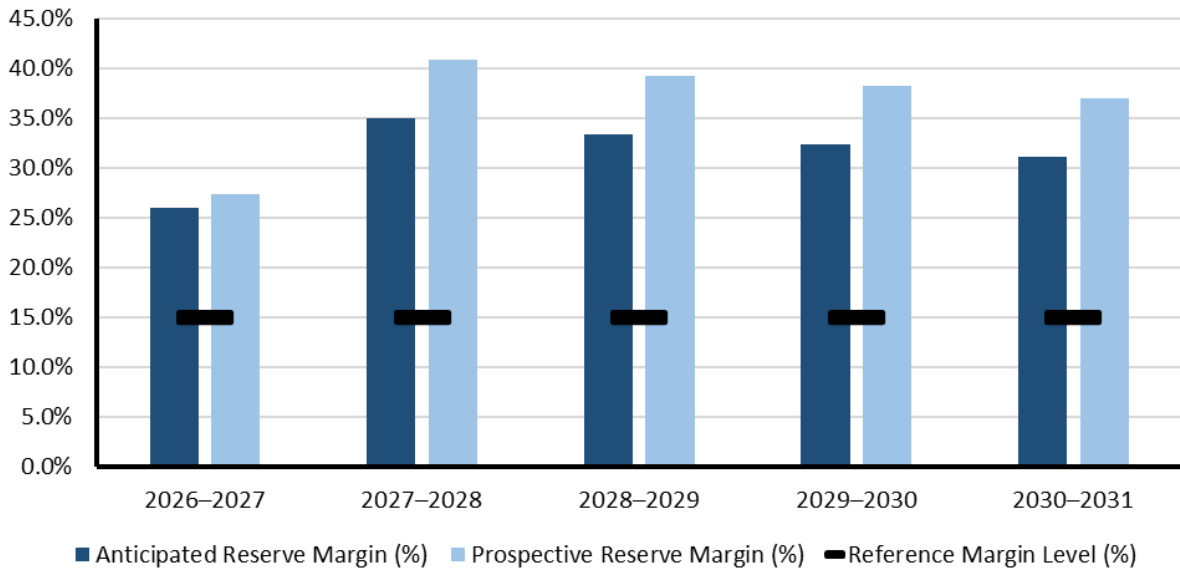


MRO-SaskPower

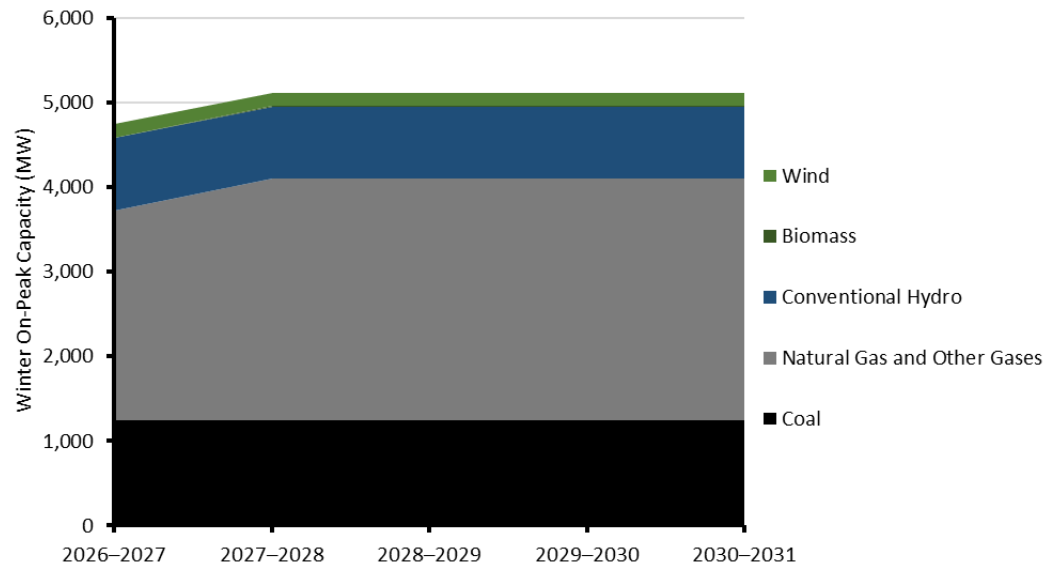
MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections. 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.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	4,040	4,112	4,148	4,180	4,205	4,230	4,278	4,314	4,347	4,375
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,968	4,040	4,076	4,108	4,133	4,158	4,206	4,242	4,275	4,303
Additions: Tier 1	90	460	460	460	460	460	460	460	460	460
Additions: Tier 2	55	241	241	241	241	241	241	241	241	241
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	315	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,907	4,992	4,976	4,976	4,961	4,962	4,900	4,962	4,976	4,892
Anticipated Reserve Margin (%)	25.9%	35.0%	33.4%	32.3%	31.2%	30.4%	27.4%	27.8%	27.2%	24.4%
Prospective Reserve Margin (%)	27.3%	40.9%	39.3%	38.2%	37.0%	35.5%	32.5%	32.8%	32.1%	29.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-SaskPower Highlights

- Over the next 10 years, MRO-SaskPower’s ARM ranges from approximately 24% to 35% and does not fall below the RML in any year. SaskPower’s recent probabilistic studies concluded that the largest contribution to EUE occurs during peak hours because of planned outages. Rescheduling maintenance can help avoid these issues.
- Saskatchewan’s average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period. Large industrial loads are the primary driver for both growth and uncertainty in SaskPower’s forecast.
- SaskPower is projected to increase its wind and solar capacity to 1,550 MW in the next three years. Natural-gas-fired generation is being added to the system to offset VERs with plans to add 525 MW nameplate of new gas-fired generation—460 MW of Tier 1 and 65 MW of Tier 2—over the next 10 years. Life extensions and repowers for coal units are in process as directed by the Saskatchewan government. SaskPower is anticipating 31.8 MW of confirmed retirements, both waste heat and wind. 174 MW of unconfirmed wind retirements may also occur over the next 10 years.
- Driven by load growth, new generation, and reliability, SaskPower is planning to expand its interconnection with SPP and add 500 MW of new transmission service over the next five years, increasing tie-line capacity to 650 MW total. Internal transmission projects totaling 180 km of new 230 kV lines are being added and an additional ~410 circuit km of transmission projects are in planning and conceptual phases over the next 5 to 10 years.
- SaskPower’s primary reliability issues include growing supply chain issues that may potentially affect their significant transmission project plans and an interdependence between Southeast Saskatchewan’s power generators and natural gas production fields. SaskPower has been managing these issues by scheduling long-lead-time components as early as possible in transmission project timelines and by working with Saskatchewan’s gas pipeline utility to coordinate and study gas system responses to losses of production receipts during power outages as incremental demand is added.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Coal	1,249	1,249	1,249	1,249	1,249
Natural Gas	2,480	2,850	2,850	2,850	2,850
Biomass	3	3	3	3	3
Wind	164	162	162	162	162
Conventional Hydro	856	856	856	856	856
Other	17	17	1	1	1
Total MW	4,769	5,137	5,121	5,121	5,121

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses two criteria for determining adequate generating capabilities. The first method is to calculate EUE through probabilistic modeling and maintain it within an acceptable level as determined through resource adequacy analysis. The second method employs a deterministic criterion in which the reserve margin for the Saskatchewan system must not fall below the RML.

Saskatchewan uses a RML of 15% and has assessed its PRM for the upcoming 10 years considering summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available DR for each year. During the 10-year assessment period, Saskatchewan’s ARM ranges from approximately 24% to 35% and does not fall below the RML in any year.

Energy Assessment, Including Non-Peak Hour Risk

Saskatchewan performs energy assessments using probabilistic methods to inform the area’s resource adequacy requirements. A detailed representation of the SaskPower system that includes load forecasts, capacity expansion sequences, individual unit characteristics, maintenance, and outages are included in the model. For VERs, SaskPower uses the ELCC methodology to periodically update capacity credits in the model. The model simultaneously considers many types of randomly occurring events, such as forced outages of generating units. Uncertainty in assumptions is addressed through scenario work based on the likelihood of occurrence (e.g. high/low hydro energy forecast, high/low load forecast).

These studies conclude that the majority contribution to the EUE is typically planned outages with unserved energy occurring mainly during peak hours. These short-term reliability issues, when identified, can be mitigated by rescheduling maintenance.

ProbA Results

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix majorly consists of baseload and fast-ramping generation resources, and it does not have a considerable penetration level of intermittent energy resources.

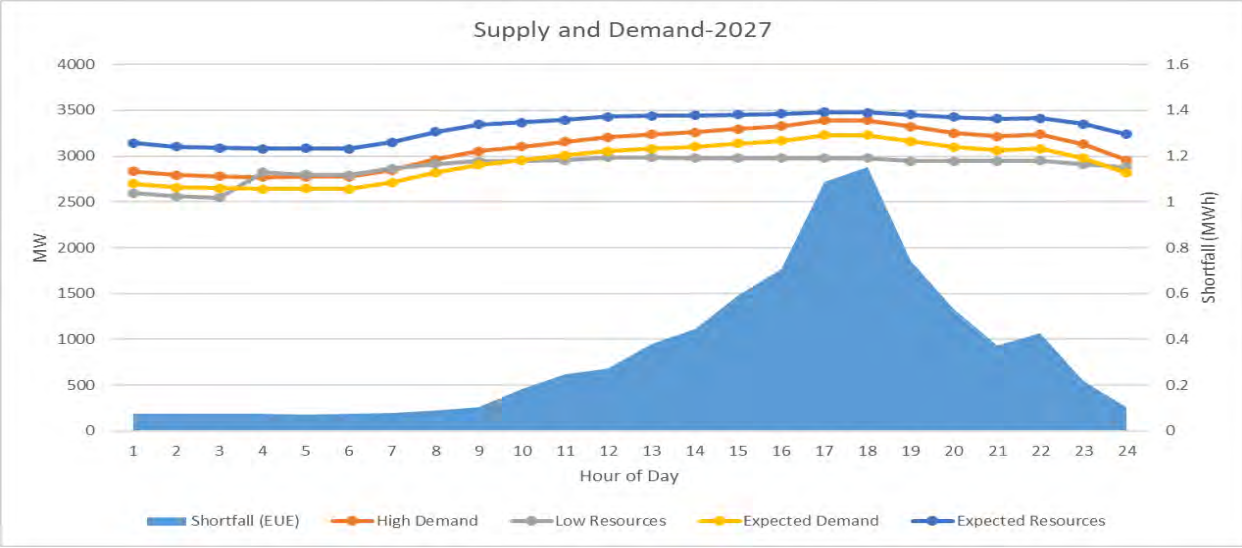
The major contribution to the EUE is planned outages. The contribution to EUE in these months occurs mainly during peak hours. These short-term reliability issues when identified can be mitigated by rescheduling the maintenance.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	75	145	5
NEUE (ppm)	2.807	5.242	0.190
LOLH (hours per Year)	0.547	1.094	0.046
* Provides the 2024 ProbA Results for Comparison			

The annual EUE heat map for 2027 is provided below.

Hourly EUE Heat Map : 2027																								
EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Feb-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%
Mar-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Apr-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
May-27	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	3%	3%	3%	3%	4%	5%	5%	3%	3%	2%	3%	2%	1%
Jun-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Jul-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%
Aug-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	2%	2%	1%	1%	1%	1%	0%	0%
Sep-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%
Oct-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%
Nov-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Dec-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Hourly demand and resource projections for the highest EUE day in 2027 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, there is a risk of supply shortfalls if demand is higher than expected and resource availability is lower than expected.



Demand

Saskatchewan experiences its peak season in the winter. Saskatchewan’s system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. SaskPower computes a coincident peak by customer category based on a combination of historical data and other factors and aggregates the coincident peaks across classes to compute the system peak.

Large industrial loads continue to be the primary reason for both growth and uncertainty in the forecast. The average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period, down slightly from the 2024 LTRA’s projection of 1.35% average annual peak demand growth.

Demand-Side Management

Saskatchewan’s DR consists of contracts with industrial customers for interruptible load based on conditions specified in established DR programs. The first of these programs provides a curtailable load, with up to 72 MW enrolled currently, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours’ notification, but those loads are not included in PRM calculations.

Distributed Energy Resources

The current behind-the-meter DER installed capacity in Saskatchewan is approximately 57 MW, which includes approximately 55 MW of solar PV and approximately 2 MW of distributed wind projects. An

additional 25 MW of DER solar PV are expected to be added in the next five years. Additional behind-the-meter DER installations are incorporated into load forecast models used for supply and transmission planning studies.

Small power producers contribute an additional 5 MW installed DER capacity (in front of the meter) in Saskatchewan. There is currently an existing 14 MW and a potential for up to 6.5 MW of DERs being added in the next year based on the currently approved Power Generation Partner program. These projects are included as generation additions, but their capacity is not currently considered in reliability planning.

Generation

Saskatchewan prepares a 10-year supply plan annually that outlines its generation plan to meet the province’s future resource needs. It considers retirements, planned and major overhauls, degradation of unit performance, escalating fuel prices, increasing capital costs, unit operating costs, and regulatory requirements. The installed capacity of non-synchronous/inverter-based generation has recently risen to 845 MW and is expected to increase to approximately 1,550 MW in the near-term planning horizon through the addition of 400 MW of wind and 300 MW of solar in the next three years. SaskPower added 370 MW of natural-gas-fired generation in 2024, which served to offset the increased net demand variations from the 220 MW of VERs added in the same year. This resulted in a slight improvement in ramping performance as compared to the last ramping assessment in 2022. SaskPower plans to add approximately 525 MW of new natural-gas-fired generation over the next 10 years and is also working to extend the life of its operational and recently deactivated coal units as directed by the Saskatchewan government.

Saskatchewan is projecting 31.8 MW (nameplate) of confirmed retirements consisting of 21.2 MW of waste heat recovery generation and 10.6 MW of wind generation. These retirements are driven by the units approaching the ends of their lifespans and terminations of power contracts. An additional 174 MW of unconfirmed wind retirements may also materialize during the 10-year assessment period.

Energy Storage

SaskPower’s first battery storage system, a 20 MW/20 MWh unit, came on-line in 2024. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/ voltage control, primary frequency control, and blackstart.

Energy Transfers

SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is currently the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity

transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation measures are in place through SaskPower’s emergency operating procedure that will allow measures such as short-term imports from available interfaces, initiating DR, and short-term load shedding.

According to the NERC’s [ITCS Canadian Analysis](#), the total simultaneous transfer capability into the Saskatchewan transmission planning region from all its neighbors, including dc-only interties, is 904 MW in the 2024 Summer and 893 MW in the 2024–2025 Winter. These values translate to approximately 25% of peak summer load and 22% of peak winter load in the analysis years. The interfaces include connections with MRO-SPP, MRO-Manitoba Hydro, and WECC-Alberta.

Transmission

SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 500 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 km of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, installation of two phase-shifting transformer interfaces, and two STATCOMs are being added. The remaining transmission projects (approximately 410 circuit km) will be in the planning or conceptual phases in the 5-to-10-year timeframe. These projects are driven by load growth, new generation additions, and reliability needs. SaskPower has historically experienced transmission limitations for existing generation deliverability in the southwest part of the province during prior outages of major transmission facilities.

Transmission infrastructure is being developed to reinforce the Northern Transmission System. SaskPower’s Northern System is not directly connected to the Southern grid, so significant load growth in the North will also require additional generation to supply the additional loads. SaskPower is looking at different ways to supply the generation to this load, including wheeling power from the South to the North through adjacent areas and temporary generation until a more permanent solution can be implemented. Planning for these projects is being driven, in part, by a projected increase in mining activity and associated development in Saskatchewan’s remote northern region. Reliable power supplies for new loads in the north will require significant transmission development.

Reliability Issues

As SaskPower is planning on constructing a significant number of transmission facilities, growing supply chain issues may affect project schedules because of long lead times for major system

components. SaskPower is identifying and initiating projects earlier that may require longer lead time and is advancing procurement as necessary.

It has been noted that there is an interdependency between Southeast Saskatchewan’s power generation and natural gas production. Saskatchewan’s pipeline utility, SaskEnergy, has completed analysis on how its system will respond to a loss of natural gas receipts during a power outage in this region as potential incremental demand is added. Both SaskPower and SaskEnergy have incorporated the potential challenges identified by that analysis into long-term planning and mitigation efforts.

SaskPower has been recently observing increasing instances of unscheduled flows on its interface with SPP and Manitoba Hydro. SaskPower is coordinating this on a regional basis with Manitoba Hydro, SPP and MISO to monitor and address the impact.

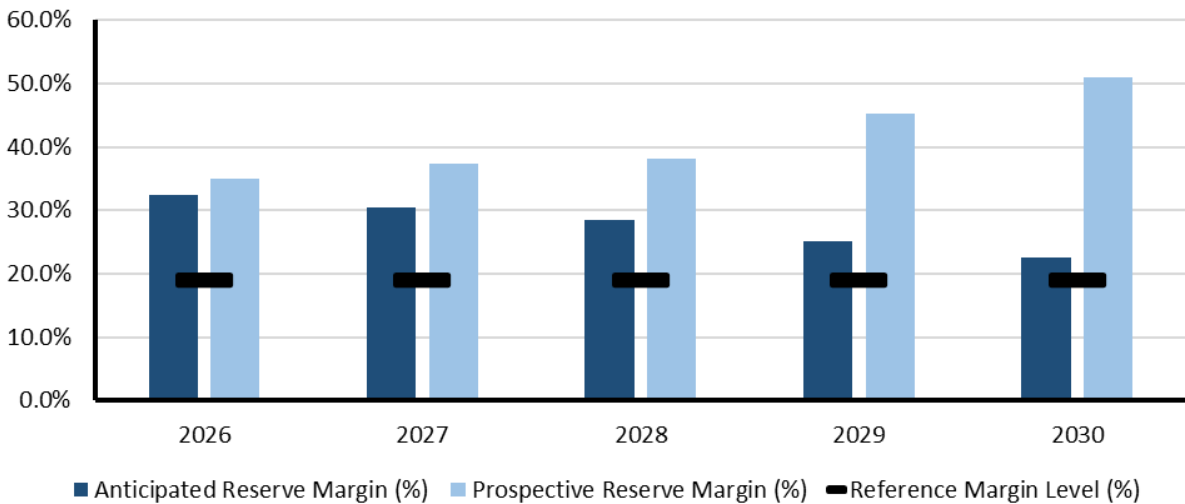


MRO-SPP

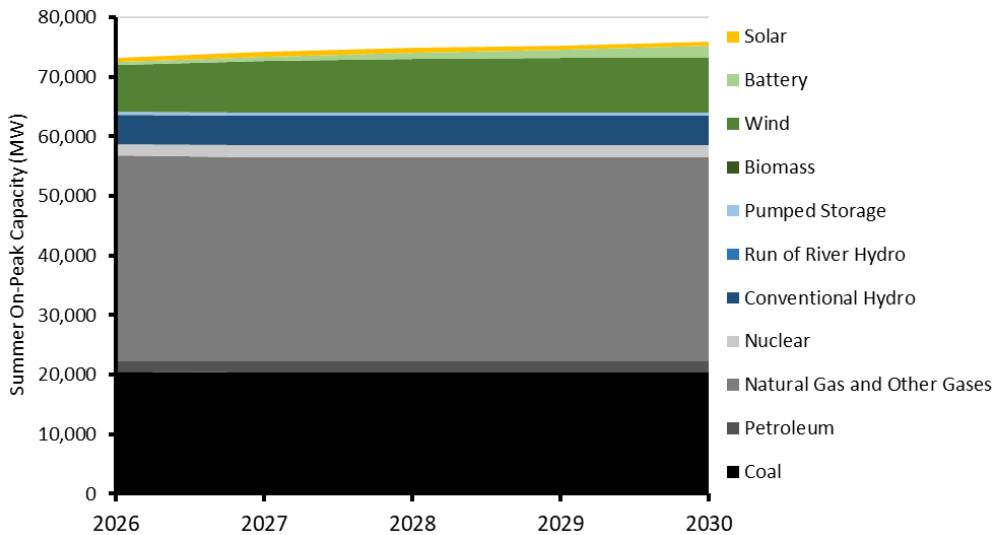
The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the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

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	57,479	59,121	60,689	62,766	64,475	66,283	66,982	67,570	68,049	68,622
Demand Response	2,138	2,162	2,332	2,508	2,509	2,511	2,513	2,514	2,718	2,720
Net Internal Demand	55,340	56,959	58,357	60,258	61,966	63,772	64,469	65,056	65,331	65,902
Additions: Tier 1	1,808	3,020	3,685	4,251	4,815	4,866	5,344	5,344	5,344	5,344
Additions: Tier 2	2,436	6,104	8,948	15,659	21,487	23,345	25,664	27,277	27,877	28,627
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-18	-78	-78	-78	-78	-79	-79	-79	-79	-79
Existing-Certain and Net Firm Transfers	71,475	71,224	71,232	71,127	71,146	71,115	71,135	71,106	71,105	71,106
Anticipated Reserve Margin (%)	32.4%	30.3%	28.4%	25.1%	22.6%	19.1%	18.6%	17.5%	17.0%	16.0%
Prospective Reserve Margin (%)	34.9%	37.3%	38.2%	45.2%	50.9%	48.7%	51.5%	51.8%	51.8%	50.6%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-SPP Highlights

- The SPP assessment area peak demand occurs during the summer season; the 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023.
- SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026.
- The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	20,473	20,440	20,440	20,428	20,428
Coal*	19,187	19,154	18,086	18,075	18,075
Petroleum	1,824	1,827	1,827	1,827	1,829
Petroleum*	1,824	1,771	1,771	1,771	1,774
Natural Gas	34,525	34,303	34,303	34,265	34,265
Natural Gas*	34,363	33,662	33,550	33,512	33,268
Biomass	35	35	35	35	35
Solar	700	700	700	700	700
Wind	7,831	8,581	9,044	9,134	9,191
Conventional Hydro	4,925	4,993	5,009	5,026	5,030
Pumped Storage	456	456	456	415	460
Nuclear	1,945	1,945	1,945	1,945	1,945
Other	281	281	281	281	281
Battery	379	833	1,027	1,472	1,949
Total MW	73,429	74,450	75,123	75,584	76,168
Total MW*	71,981	72,467	71,960	72,422	72,762
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.					

MRO-SPP Assessment

Planning Reserve Margins

The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029. SPP has approved a non-coincident 16% PRM for the 2026 Summer season and a 36% PRM for the 2026–2027 Winter season. Additionally, a non-coincident 17% PRM for the 2029 Summer season and 38% PRM for the winter season was approved as well. The PRM increases are not reflected in the 2025 LTRA as they are tied to policies that are still before FERC. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to drop below the current 19% RML in 2032 and remain below that RML for the remainder of the 10-year horizon.

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

SPP is performing a yearly energy adequacy assessment and assessment of adequacy of reliability attributes, which will be presented to SPP stakeholders. The results will also be used to perform for all reliability attributes a biennial assessment of the need for new market products, changes to market functionality, and changes to resource adequacy policies or requirements. Results of the biennial reassessment will be provided to impacted SPP stakeholder groups and the Regional State Committee (RSC).

Southwest Power Pool (SPP) performs an LOLE analysis every two years to determine the adequate amount of planning reserves needed to maintain a reliability metric of one day (or less) in ten years. SPP’s 2023 LOLE study supported much of the demand forecast presented in NERC’s 2024 LTRA and demonstrated how the PRM could be impacted materially depending upon how much loss of demand risk was planned for each season (winter or summer). Directed by the RTO’s Resource and Energy Adequacy Leadership Team, SPP completed an out-of-cycle 2024 LOLE analysis published in April 2025 to develop a recommendation for 2029 seasonal PRMs. This study and its results are based on the 2024 member-submitted forecast for the resource mix and demand, using the 2023 LOLE study assumptions. Member-submitted demand forecast increased approximately 5% in summer and 6% in winter for planning year 2029.

ProbA Results

The 2025 ProbA study was performed on assumptions, and the accompanying methodology reflects methods used in SPP’s LOLE studies, which have been thoroughly vetted through the SPP stakeholder process. Study improvements include additional weather years, seasonal forced outage modeling from the previous NERC probabilistic study, and incremental cold weather outages. More information on improvement and methodology can be found in SPP’s LOLE study reports.

There was no observed unserved energy for years two and four of the base-case analysis for the SPP assessment area. This is most likely attributed to an increase of conventional thermal generations more than that of renewable resources and the delayed retirements of other thermal resources to meet the increasing projected demand needs. Since there are no observed load-loss events, additional reporting is not provided.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
*Provides the 2024 ProbA Results for Comparison			

Demand

The SPP assessment area is a summer-peaking region and currently relies on the forecast submitted by the load responsible entities in the annual resource adequacy process. The 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023. Although actual demand is very dependent on weather conditions and typically includes the effects of interruptible loads, forecasted net internal demands are based on a 10-to-30-year average of summer weather, or 50/50 weather. Some SPP RTO members base their peak load forecasts on a 50% confidence level, as approved by their respective state commission(s). This means the actual weather on the peak summer day is expected to have a 50% likelihood of being hotter and a 50% likelihood of being cooler than the weather assumed in deriving the load forecast. SPP RTO members make economic assumptions in their individual forecasting methods as well consider the effects of non-controllable or dispatchable programs and resources within their area. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has seen in recent peak season.

Although SPP’s energy projections for resource adequacy purposes differ from load interconnection process set forth in the SPP OATT, the SPP Assessment Area has received new load requests for data center, pipeline, oil and gas, irrigation and industrial load. While these loads represent above average load growth in areas, some of the load due to oil and gas exploration have decreased. Of current concern is the projected growth in the crypto load area and how much of that will turn into demand growth outside of the DR arena.

Demand-Side Management

SPP RTO members track dispatchable and controllable DR programs, which are used as peak load shaving programs. For resource adequacy purposes, the peak demand can be reduced by the impacts of the programs to determine an appropriate net peak demand for each member. SPP’s tariff requires each Load Responsible Entity (LRE) to qualify and test their programs to prove they can meet and maintain the level of reduction submitted annually in the resource adequacy compliance window. SPP is constructing new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources

The SPP assessment area is forecasting ~70 MWs of DERs in the 5–10-year planning horizon. The impacts and assumptions may differ across the planning processes, for instance in some studies they may be used to reduce the load impacts whereas in other studies they may be modeled as a resource that has a high cost associated with it. SPP does not consider the impacts of BTM resource as a load reduction for purposes on resource adequacy compliance.

Generation

In general, SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026. There has been minimal retirement reported since the *2024 LTRA*, and a number of resources identified in 2024 as being set to retire are now being converted to new fuel, mostly coal to gas.

The *Expedited Resource Adequacy Study* process, approved by FERC in July 2025, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs. The program is yielding additional natural-gas-fired, solar, and battery resource projects in SPP’s Tier 2 development queue. Nearly 8 GW of natural-gas-fired generator capacity, 2.2 GW nameplate in solar, and 1.8 GW nameplate in batteries have been added to SPP’s Tier 2 queue since

July and are not reflected in this year’s LTRA. SPP anticipates the first interconnection agreements for *Expedited Resource Adequacy Study* projects will be signed in early 2026, which will qualify these resources for Tier 1 in NERC’s reliability assessments and ProbA and count toward ARM.

Energy Storage

There are approximately 57,000 MWs of energy storage and hybrid resources in generator interconnection queues. There are about 50 MWs that are under contract by members across the SPP assessment area and 230 MW of nameplate capacity forecasted for the assessment timeframe. These resources are being modeled as generation in the planning assumptions both near and long term. Due to this limited amount of storage, limited operational impacts have been identified.

Capacity Transfers

Over the assessment time frame, SPP is forecasting, based on submitted member data, to be a net exporter of capacity. In the resource adequacy process, SPP only relies on the imports that have firm transmission service, which is ~2,000 MWs. SPP and ERCOT executed a Coordination Plan, which addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the Coordination Plan based on the latest discussions and business decisions related to resource priority.

Transmission

SPP’s [2024 Integrated Transmission Plan \(ITP\)](#) is the single largest portfolio, in terms of size and value, that SPP has proposed for construction in its 20-year history as a transmission PC. The approved plan includes 89 transmission upgrades needed to address increasing electricity consumption and changes in the region's generating fleet.

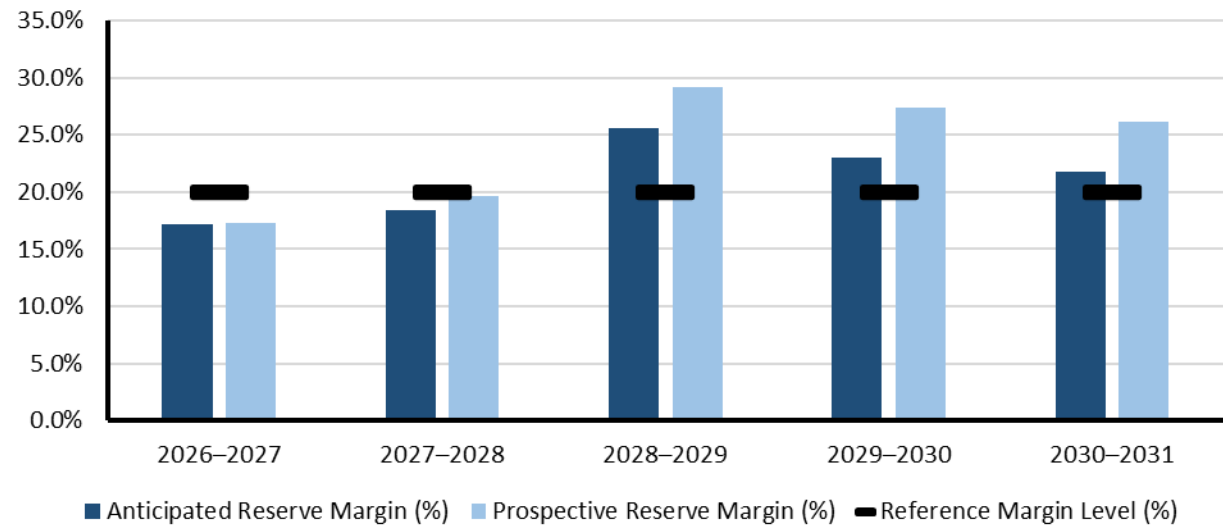


NPCC-Maritimes

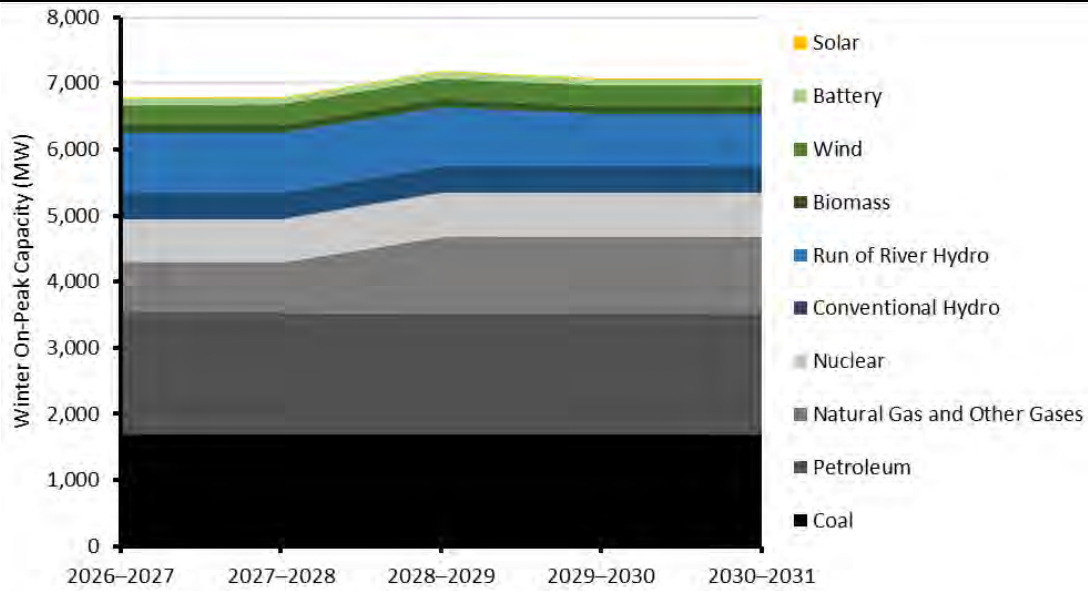
NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. State of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 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.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	6,107	6,157	6,194	6,231	6,292	6,346	6,380	6,493	6,579	6,669
Demand Response	264	283	290	291	290	291	290	291	290	290
Net Internal Demand	5,843	5,875	5,904	5,940	6,001	6,055	6,089	6,202	6,289	6,380
Additions: Tier 1	173	179	579	579	579	579	579	579	579	579
Additions: Tier 2	6	367	656	1,492	1,492	1,492	1,492	1,492	1,492	1,492
Additions: Tier 3	0	0	23	101	215	227	239	251	260	260
Net Firm Capacity Transfers	-32	75	145	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	6,673	6,780	6,838	6,727	6,727	6,727	6,621	6,621	6,596	6,707
Anticipated Reserve Margin (%)	17.2%	18.5%	25.6%	23.0%	21.7%	20.7%	18.2%	16.1%	14.1%	14.2%
Prospective Reserve Margin (%)	17.3%	19.6%	29.2%	27.4%	26.1%	25.0%	22.6%	20.3%	18.3%	18.3%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Maritimes Highlights

- Since the 2024 LTRA, the overall resource outlook has diminished slightly with smaller peak capacity contributions from certain wind, hydro, and biomass resources through most of the planning period. Starting in 2026, winter peak demand forecasts for this assessment area have risen slightly from the previous year’s projection through most years of the planning horizon; however, ARMs are currently projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,410	1,003	691
Petroleum	1,831	1,831	1,820	1,820	1,820
Natural Gas	757	757	1,157	1,157	1,157
Biomass	129	129	129	129	129
Solar	10	10	10	10	10
Wind	300	306	306	306	306
Conventional Hydro	395	395	395	395	395
Run of River Hydro	901	901	901	790	790
Nuclear	663	663	671	671	671
Other	98	98	89	89	89
Battery	99	99	99	99	99
Total MW	6,878	6,884	7,272	7,161	7,161
Total MW*	6,878	6,884	6,986	6,468	6,156
* Capacity with additional generator retirements. Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

NPCC-Maritimes Assessment

Planning Reserve Margins

The RML that is used for evaluating the New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM) sub-areas comprising the Maritimes area is 20% of firm load. The 20% criterion is not a mandated requirement. The ARM over the study period for the Maritimes area ranges between 14% to 26% during the winter period and between 74% to 90% during the summer period.

The ARM level during off-peak season for the Maritimes areas ranges between 74% to 90%. During off-peak hours, the Maritimes area has surplus generation available to meet the area’s energy needs and hence there are no constraints with converting the capacity to energy during these times.

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

Energy Risk

During off-peak hours, the Maritimes area has surplus generation available to meet the area’s energy, needs and hence there are no constraints with converting the capacity to energy during these times.

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

ProbA

For the Maritimes area, the ProbA indicates elevated levels of unserved energy in February 2028 due to load growth projections and the characteristics of the resource mix during that period and with a few hours of risk in the shoulder months of December and January.

Annual metrics and requested enhancements including EUE heat maps, loss of load event analysis, and risk period visualizations for both 2027 and 2029 are included in the ProbA appendix.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	5	15	7
NEUE (ppm)	0.17	0.52	0.25
LOLH (hours/year)	0.09	0.25	0.10
*Results from the 2024 ProbA simulations			

Resource additions described in the Generation section below contribute to the improved EUE and LOLH metrics for study year 2029.

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period.

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.8% in summer and 1% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 6.6% during the 10-year assessment period for an average growth of 0.7% per year. Demand and energy forecasts have risen since the 2024 LTRA, due in large part to rural-to-metropolitan population migration and the proliferation of heat pump technology in local areas previously heated by fossil fuels, primarily in the PEI region.

Demand-Side Management

Plans to develop up to 100 MW by 2030–2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 21 MW to 147 MW

while the annual amounts for winter peak demand reductions rise from 177 MW to 652 MW.³⁷ The total controllable and dispatchable DR increases from 328 MW to 337 MW in the summer period while increasing from 248 MW to 290 MW in the winter period.

Distributed Energy Resources

The DER installed capacity in NS is approximately 300 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff and BTM solar.

LTRA wind capacity for NB, NS, and PEI is de-rated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. Behind-the-meter (BTM) solar is assumed to have an ELCC of 0% during the winter period. The Maritimes area has shown embedded BTM solar PV projections of 204 MW in 2025 rising to 1,261 MW by 2035. These projects include distributed small-scale solar (mainly rooftop) projects that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of area’s system peak which occurs either before sunrise or after sunset in the winter period.

Generation

NB plans to extend 28 MW diesel fired generator starting in 2025 and recently upgraded 277 MW of natural-gas-fueled resource completed in 2023. An anticipated replacement PPA contract, a long-term firm energy contract from neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

In New Brunswick, Tier 1 resources include 63 MW (installed capacity) of wind and 400 MW of combustion turbines. Tier 2 resources include 546 MW of wind resources and 72 MW of biomass.

In Nova Scotia, Tier 1 resources include wind projects with a total installed capacity of 635MW phased-in from 2025–2027. These projects include 306 MW as part of the provincial Rate Base Procurement program, a 168 MW wind project, a 12.5 MW wind project, and a 148 MW wind project under the Renewable to Retail tariffs. Tier 1 resources in NS also include a 150 MW battery (2025–2026). Tier 2 resources in NS include 600 MW of combustion turbines (2027–2029); a 150 MW conversion of a coal-fired unit to natural gas (2028); 459 MW conversion of coal-fire units to oil (2030); 250 MW of batteries (2027–2029); 262 MW of wind projects as part of the provincial Green Choice Program

³⁷ Current and projected EE effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized

(2028–2029); and approximately 100 MW of solar independent power producer (IPP) projects (2026-2029) with an ELCC of 0%. Tier 3 resources in NS include new wind generation with a nameplate capacity of 1400 MW phased in from 2029-2034.

PEI has 30 MW installed capacity of tier 2 wind, 111 MW tier 3 wind, 140 MW of tier 3 Petroleum based generation and 10 MW of tier 3 batteries.

NB de-rates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI de-rate wind capacity to 18% and 17% respectively of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes Area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource (2025–2026) and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource (2027–2029). These grid scale projects will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 3 resource starting summer of 2028.

NB Power has not included any energy storage resources in the 2025 LTRA submission; however, the value of energy storage options is expected to increase as the technology improves and as NB’s smart grid network develops. NB Power issued a request for expressions of interest (REOI) for new renewable generation sources, including 200 MW wind, 15 MW solar, 5 MW tidal, and 50 MW 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources such as wind to provide additional flexibility to the system.

in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

Capacity Transfers

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

Transmission

NS has multiple new transmission line projects compared to the 2025 LTRA, most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues

The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (de-rated), dual fuel oil/gas, tie benefits, and biomass with no one type feeding more than about 32% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges to resource during the assessment period.



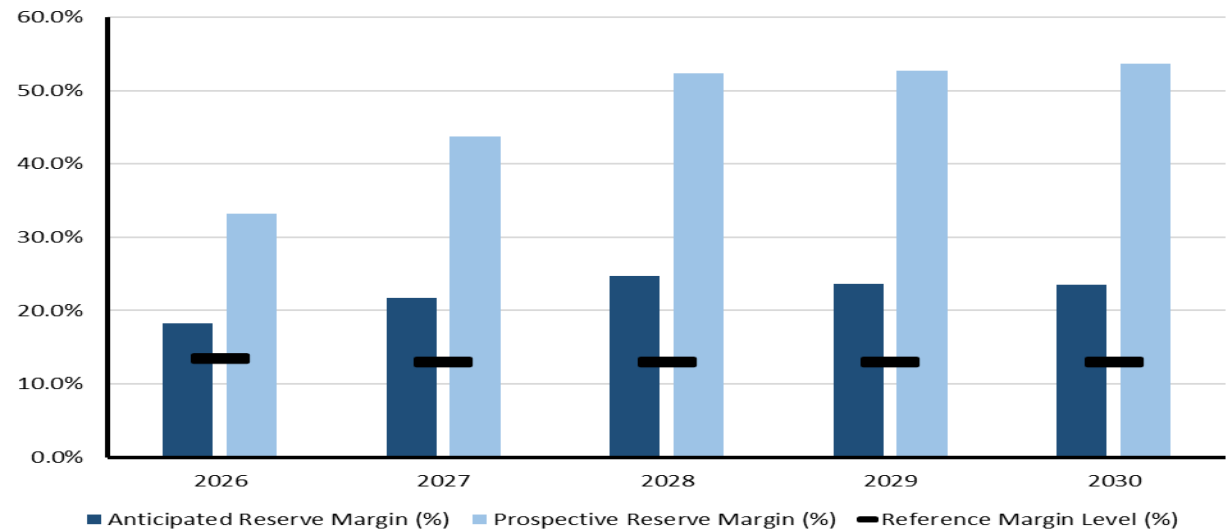
NPCC-New England

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

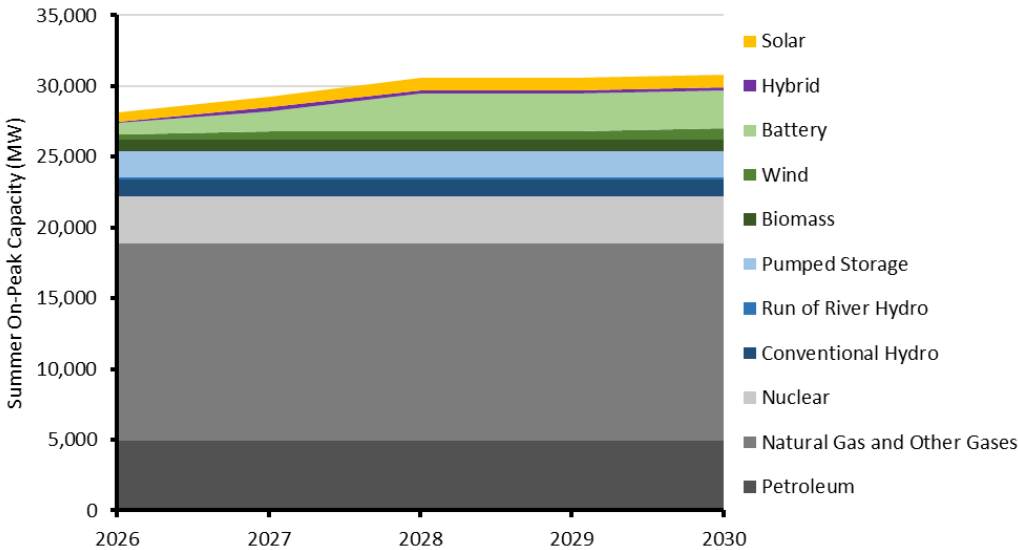
The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	24,877	24,945	25,124	25,347	25,557	25,821	26,123	26,486	26,897	27,331
Demand Response	623	544	544	544	544	544	544	544	544	544
Net Internal Demand	24,254	24,401	24,580	24,803	25,013	25,277	25,579	25,942	26,353	26,787
Additions: Tier 1	1,081	2,183	3,543	3,551	3,781	3,781	3,913	3,913	4,263	4,263
Additions: Tier 2	1,113	2,871	4,274	4,687	5,037	5,037	5,037	5,387	5,387	5,387
Additions: Tier 3	872	4,129	10,335	11,426	11,830	12,924	12,924	12,924	12,924	12,924
Net Firm Capacity Transfers	567	465	84	84	84	84	84	0	0	0
Existing-Certain and Net Firm Transfers	27,607	27,505	27,124	27,124	27,124	27,124	27,124	27,040	27,040	27,040
Anticipated Reserve Margin (%)	18.3%	21.7%	24.8%	23.7%	23.6%	22.3%	21.3%	19.3%	18.8%	16.9%
Prospective Reserve Margin (%)	33.2%	43.7%	52.3%	52.7%	53.7%	52.1%	50.8%	49.7%	48.7%	46.3%
Reference Margin Level (%)	13.4%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-New England Highlights

- New England is forecast to have sufficient seasonal ARMs needed to meet consumer demand for electric energy for the entire assessment period (2026–2035) and not require any Tier 2 resources.
- Ongoing developments of wind facilities and a new interregional tie with Canada (the [New England Clean Energy Connect](#)) as well as new technologies (such as longer-duration electricity storage) will likely continue the trend toward a cleaner, albeit more complex, power system. ISO-NE is addressing the issues brought on by grid transformation through a number of planning, operational, and market measures.
- The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW) ³⁸					
	2026	2027	2028	2029	2030
Petroleum	4,899	4,899	4,899	4,899	4,899
Natural Gas	13,939	13,939	13,939	13,939	13,939
Biomass	776	776	776	776	776
Solar	645	726	864	872	872
Wind	416	622	622	622	852
Conventional Hydro	1,165	1,165	1,165	1,165	1,165
Run of River Hydro	179	179	179	179	179
Pumped Storage	1,864	1,864	1,864	1,864	1,864
Nuclear	3,351	3,351	3,351	3,351	3,351
Hybrid	96	287	287	287	287
Battery	791	1,416	2,638	2,638	2,638
Total MW	28,121	29,223	30,584	30,591	30,821

- The winter ARMs do not fall below the annual RMLs for the entire assessment period.

³⁸ MW totals reflect existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

The winter ARMs do not fall below the annual RMLs for the entire assessment period. The winter ARMs range from a surplus high of 10,651 MW (66% ARM) in winter 2027–28 and then decrease each year to a surplus low of 4,522 MW (30% ARM) in winter 2035–36. The larger surpluses during winter (vs. summer) reflect the fact that New England is currently summer-peaking.

With the continued development of renewable and clean energy resources, the system will continue to emit lower air emissions.

Planning Reserve Margins

ISO-NE’s installed capacity requirement (ICR) is based on the capacity needed to meet NPCC’s resource adequacy reliability criterion. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period (CCP). The latest ICR calculations result in an LTRA annual RML of 13% in 2026 and 2027, expressed in terms of the annual 50/50 peak demand forecast. For the years 2028 through 2035, ISO-NE continued to use the last available RML value of 13%.

Energy Risks (Including Non-Peak Hour Risk)

ISO-NE routinely prepares a 21-day energy assessment forecast and report. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the regional supply/demand balance is projected to be negative, then projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential electricity shortages should incentivize market participants to procure whatever is necessary (fuel) to follow future ISO dispatch orders. ISO-NE publishes its 21-day energy assessments every 2 weeks during spring, summer, and fall and then increases these publications to weekly (and/or daily if necessary) during the winter.

ISO-NE worked with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. The modeling results for the near-term PEAT assessments show for Summer 2027 that no energy shortfalls were observed in any of the events. One operating reserve shortfall was observed within a long-duration heat wave coincident with low wind scenario. For Winter 2027, a range of energy shortfall risks and associated probabilities were observed:

- The energy shortfall risk appears manageable over a 21-day period.

- These modeling results are consistent with the significant quantities of PV (BTM and utility scale), wind, and energy/electricity storage expected while experiencing minimal load growth.
- Operating risks may be mitigated by incremental imports from large inter-area transmission interconnects.

The modeling results for Summer 2032 also show that no energy shortfalls were observed in any of the hours of the 21-day period and only 1 hour of 30-minute reserve shortfall was observed. Baseline studies of Summer 2032 events indicate an energy shortfall risk similar to that of Summer 2027 events.

The modeling results for Winter 2032 show that the energy adequacy risk profile is dynamic and will be a function of the evolution of both supply and demand profiles. These results also reveal the range of energy shortfall risk under a variety of resource mix and demand assumptions. In terms of magnitude and probability, baseline studies of Winter 2032 events indicate an energy shortfall risk profile akin to that of Winter 2027 event studies.

Probabilistic Assessments (ProbA and Other Studies)

In conjunction with NPCC, ISO-NE conducts annual probabilistic resource adequacy assessments to identify regional capacity resource needs and to comply with NPCC/NERC reliability criterion/requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated transmission planning activities with neighboring systems will continue in support of the New England states’ policy objectives of providing access to a greater diversity of clean energy resources and to comply with environmental regulations.

New England is a summer-peaking area. For the ProbA years, New England presents negligible risks in 2027 and very low risk in 2029 based on the ProbA results shown below.

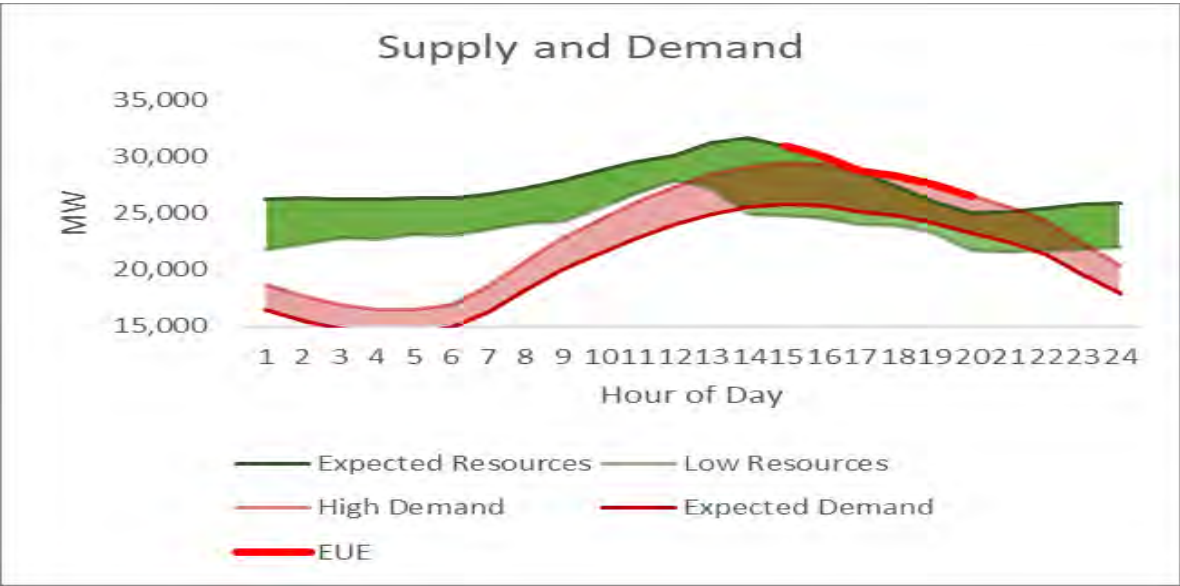
NPCC New England Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	10.7	0.1	1.8
NEUE (ppm)	0.1	0.0	0.0
LOLH (hours per Year)	0.1	0.0	<0.1
* Provides the 2024 ProbA results for Comparison			

EUE Heat Map – 2029

For the 2029 summer season, the highest EUE risks are driven by high demand and low resources availability.

Month	Hour																							
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	10%	33%	24%	1%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	19%	5%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

The figure below illustrates hourly demand and resource projections for the highest EUE day in 2029.



Demand

For its 2025 forecast, ISO-NE has updated its long-term forecast methodology to include hourly modeling of all load components, incorporation of climate-adjusted weather in forecast simulation, redefinition of gross load to reflect reconstitution for BTM solar PV (BTM PV) only, and an expanded forecast horizon that extends to 2045. This new base load forecast also already implicitly accounts for the load reduction from EE.

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,094 MW from 24,803 MW in 2025 to 26,897 MW in 2034. The corresponding net internal winter peak demand increases by 5,964 MW from 20,056 MW in 2025–26 to 26,020 in 2034–35. Net energy for load is forecast to grow by 13,403 GWh from 117,262 GWh in 2025 to 130,665 GWh in 2034. These peak growth projections have not changed significantly since the 2024 LTRA. The energy growth projection has decreased as well since the 2024 LTRA.

The higher winter peak growth rate due to anticipated electrification results in convergence with summer peak projections by the end of the 10-year period, such that New England’s transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by that time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management (DR/DSM)/Distributed Energy Resources (DER)

For Summer 2026, ISO-NE forecasts 623 MW of controllable and dispatchable DR/DSM resources, which is projected to decrease to 544 MW by the summer of 2027. That value is then held constant through the rest of the assessment period.

For summer months, the results of the BTM PV forecast are incorporated into the ISO-NE gross demand forecast as estimated reductions in demand. In the summer of 2026, New England is expected to have 1,759 MW (5,093 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,942 MW (7,359 MW nameplate) by 2031. The winter capacity contribution for BTM PV resources is currently 7 MW (5,372 MW nameplate) in the winter of 2026–27 and increases to 521 MW (9,360 MW nameplate) in the winter of 2035–36.

In 2024, ISO-NE developed a new [Planning Procedure 12](#) entitled *Data Collection for Distributed Energy Resources* to formalize and standardize data collection for DERs. Under this new planning procedure, distribution providers are responsible for providing installation-level data on DERs connected to their system (these DERs do not include DR, controllable loads, or other load modifiers). Additionally, transmission providers are responsible for providing data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits, this planning procedure will allow for proper accounting of the location, size, and type of DER, which will lead to more accurate operational and planning studies.

Generation

The two largest changes that will impact New England’s generation fleet are the changes to the methodology for capacity accreditation and the development of a seasonal, prompt capacity market. Efforts are underway to change the timing and commitment horizons of capacity auctions to

seasonal/prompt in preparation for the evolving resource mix the [Capacity Auction Reforms Key Project](#).

While ISO-NE does not expect any reliability impacts due to the retirement of any one single unit or station, the past and future retirements of dispatchable, fossil-fueled capacity, with on-site fuel inventories, as well as potential nuclear plant retirements, continue to exacerbate known winter reliability issues related to natural gas availability.

Energy Storage

New England has a total of 2,331 MW/2,110 MW (summer/winter rating) of energy storage capacity. Among the largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,864 MW / 1,861 MW (summer/winter rating) of quick-start 10-minute operating reserve capability, and with full reservoirs, can produce over 11,800 MWh of energy.

New England currently has 467 MW/249 MW (summer/winter rating) of electricity storage, including traditional battery storage along with integrated hybrid and co-located hybrid electricity storage.

As of April 1, 2025, there were 16,885 MW (summer ratings) of electricity storage devices (batteries, integrated-hybrid, and co-located-hybrid) that have submitted interconnection requests for installation over the next five years under the combined resource categories of Tier 1 at 2,658 MW, Tier 2 at 3,258 MW, and Tier 3 at 10,969 MW.

No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase/decrease from their 5-year projection.

Capacity Transfers (Reliance on Assistance)

New England is interconnected to three BAs: Québec, Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to meet the regional resource adequacy criterion while preventing over-reliance on such assistance. Assumed assistance from tie benefits ranges from 2,100 MW in 2026 to 2,115 MW in 2027. Aside from such assistance, ISO-NE’s firm capacity imports are projected to range from a maximum of 567 MW in the summer of 2026 to 84 MW in the summer of 2028. There is one long-term firm import contract of 84 MW that extends from Summer 2028 through Summer 2032.

Within the 2025 LTRA Prospective Resources (and Prospective Reserve Margin in the Demand, Resources, and Reserve Margins table), a summer and winter, energy-only contract is identified (i.e., expected imports). These numbers reflect the upcoming commercialization (in late 2025) of the New

England Clean Energy Connect (NECEC), a new 1,200 MW tie line connecting Québec to Lewiston, Maine. An off-take 1,090 MW energy-only contract into Maine/New England has been executed. This import of 1,090 MW reflects the average hourly rate of the total annual energy in the contract.

In addition, there are no firm exports identified over the 10-year LTRA summer or winter assessment periods.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs that use inverter-based technology and changes to mandatory planning criteria promulgated by NERC and NPCC have driven the need for increasingly complex transmission assessments.

The future reliable and economic performance of the system is expected to continue to improve because of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of inverter-based technologies, and issues arising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. ISO-NE’s longer-term transmission planning process was developed through coordination with NESCOE to create an additional path toward meeting these future system needs.

Reliability Issues

New England’s power system is transitioning to a system with unprecedented projected demand growth and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE has been engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall power system reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected “in-service” dates for transmission system upgrades due to supply chain issues. In these cases, ISO-NE develops special operating plans to work around any issues caused by these commercialization delays.

New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. In winter, the interstate natural gas pipelines serving New England run full with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. In response, ISO-NE has been a key player at the national level in promoting electric/gas

communications/coordination, sharing of lessons learned, best practices, and more recently, through the performance of more detailed and in-depth deterministic and probabilistic energy assessments.

The just-in-time delivery of a generator’s fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy/electricity—either through long-term energy/electricity storage solutions that can capture and store renewable power or through the use of flexible, dispatchable resources.

ISO-NE is actively working on numerous major projects as part of its energy transition while ensuring continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

- [Capacity Auction Reforms](#)
- [Operational Impacts of Extreme Weather Events](#)
- [Day-Ahead Ancillary Services Initiative](#)
- [2024 Economic Study](#)
- [Extended-Term Transmission Planning Tariff Changes](#) (aka Longer-Term Transmission Planning (LTTP) Tariff Changes)
- [Longer-Term Transmission Studies](#)
- [Storage As Transmission Only Asset](#)
- [FERC Order No. 1920 Project](#)
- [FERC Order No. 2023 Project](#)
- [FERC Order No. 2222 Project](#)

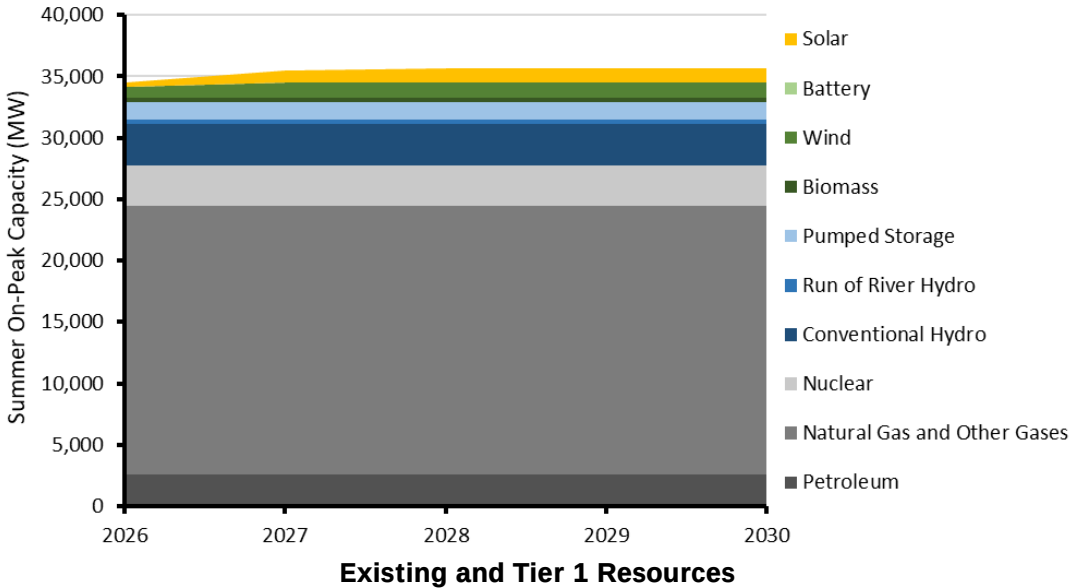
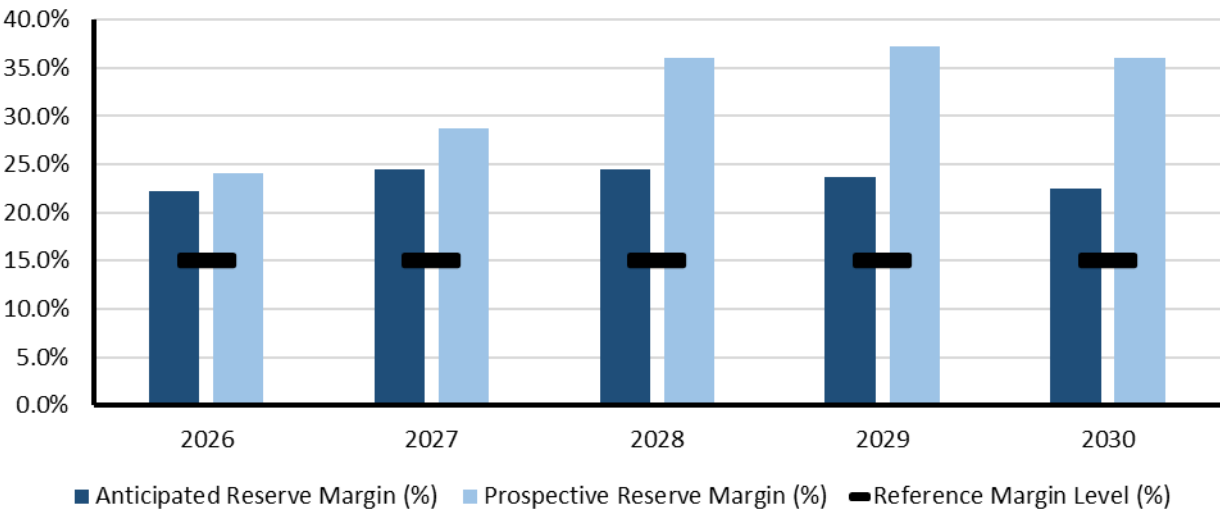


NPCC-New York

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 encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	31,990	32,280	32,410	32,620	32,910	33,190	33,520	33,870	34,170	34,500
Demand Response	989	989	989	989	989	989	989	989	989	989
Net Internal Demand	31,001	31,291	31,421	31,631	31,921	32,201	32,531	32,881	33,181	33,511
Additions: Tier 1	532	1,509	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,660
Additions: Tier 2	574	1,317	3,642	4,313	4,313	4,313	4,313	4,313	4,313	4,313
Additions: Tier 3	150	1,516	9,280	19,034	25,847	28,035	28,035	28,526	29,009	29,009
Net Firm Capacity Transfers	3,405	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486
Existing-Certain and Net Firm Transfers	37,368	37,449	37,450	37,450	37,450	36,995	36,995	36,995	36,995	36,995
Anticipated Reserve Margin (%)	22.3%	24.5%	24.5%	23.6%	22.5%	20.0%	18.8%	17.6%	16.5%	15.4%
Prospective Reserve Margin (%)	24.1%	28.7%	36.1%	37.3%	36.0%	33.4%	32.1%	30.7%	29.5%	28.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



NPCC-New York Highlights

- Generator deactivations are outpacing new supply additions. Electrification programs and new large-load customers associated with economic development initiatives are pushing projected demand higher. Together, these forces are also narrowing reliability margins across New York and increasing the risk of future reliability needs.
- As public policy goals seek to decarbonize the grid, fossil-fired generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. EE and demand-side management (DSM) will continue to play a key role in reducing energy consumption, lowering costs, and mitigating environmental impacts.
- Some of the risks can be mitigated by repowering. Repowering aging power plants can lower emissions, meet rising consumer demand, and provide reliability benefits to the grid that are needed to integrate additional clean energy resources.
- New York is projected to become a winter-peaking electric system by the 2040s, driven primarily by electrification of space heating and transportation. On the coldest days, the availability of natural gas for power generation can be limited, and interruptions to natural gas supply will introduce further challenges for reliable electric grid operations.
- Driven by public policies, new supply, load, and transmission projects are seeking to interconnect to the grid at record levels. NYISO’s interconnection processes continue to evolve to balance developer flexibility with the need to manage the process to more stringent time frames. New processes have been implemented to accelerate the process while protecting grid reliability.
- The competitive wholesale electricity markets administered by NYISO support reliability while minimizing costs to consumers. Competitive wholesale markets are essential to a reliable, affordable, and cleaner grid of the future.
- NYISO’s 2025 Quarter 3 Short-Term Assessment of Reliability (STAR)³⁹ report identified short-term reliability needs in New York City and Long Island due to generation deactivations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Petroleum	2,597	2,597	2,597	2,597	2,597
Natural Gas	21,858	21,858	21,858	21,858	21,858
Biomass	334	334	334	334	334
Solar	345	931	1,083	1,083	1,083
Wind	850	1,221	1,221	1,221	1,221
Geothermal	0	0	0	0	0
Conventional Hydro	3,324	3,324	3,324	3,324	3,324
Run of River Hydro	418	418	418	418	418
Pumped Storage	1,411	1,411	1,411	1,411	1,411
Nuclear	3,326	3,326	3,326	3,326	3,326
Hybrid	0	0	0	0	0
Other	0	0	0	0	0
Battery	32	52	52	52	52
Unknown	0	0	0	0	0
Total MW	34,495	35,472	35,623	35,623	35,623

³⁹ NYISO’s 2025 Q3 STAR Report: <https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf>; Explanatory Statement: https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; and Solutions Solicitation: <https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf>

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system’s resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO’s *2024 Reliability Needs Assessment*⁴⁰ found reliability margins decrease over time as load increases to the point that New York is nearly at the 0.1 even-days/year criteria by 2034.

NYISO also provides support to the New York State Reliability Council (NYSRC) in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC’s resource adequacy criterion of “one day in 10 years.” The current IRM for the 2025–2026 capability year is 24.4% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 24.4%. Additionally, NYISO performs an annual study to identify the Locational Minimum Installed Capacity Requirements (LCRs) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State’s Climate Leadership and Community Protection Act (CLCPA) decarbonization mandates to decarbonize span all major industries and are the main drivers of change to the electric system NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid’s transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFR) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system’s balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource

adequacy studies through NYISO’s reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO’s Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement, and certain combined-cycle gas units participate in a “Minimum Oil Burn” program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and Other Studies)

NYISO performs probabilistic assessments using GE’s Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes, as well as supporting the calculation of the annual IRM, LCRs, and capacity accreditation. The new capacity accreditation market rules align compensation for capacity suppliers with an individual resource’s expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The CAFs will reflect the marginal reliability contribution of the ICAP suppliers within each capacity accreditation resource class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

Additionally, every year, each Regional Entity (e.g., NPCC) provides results into NERC’s ProbA process under the LTRA. The results from the ProbA performed in 2025 by the NPCC Regional Entity are shown below.

ProbA Results

New York is a summer-peaking area with negligible risks as shown in the low values in the following table of annual metrics.

⁴⁰ <https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf>

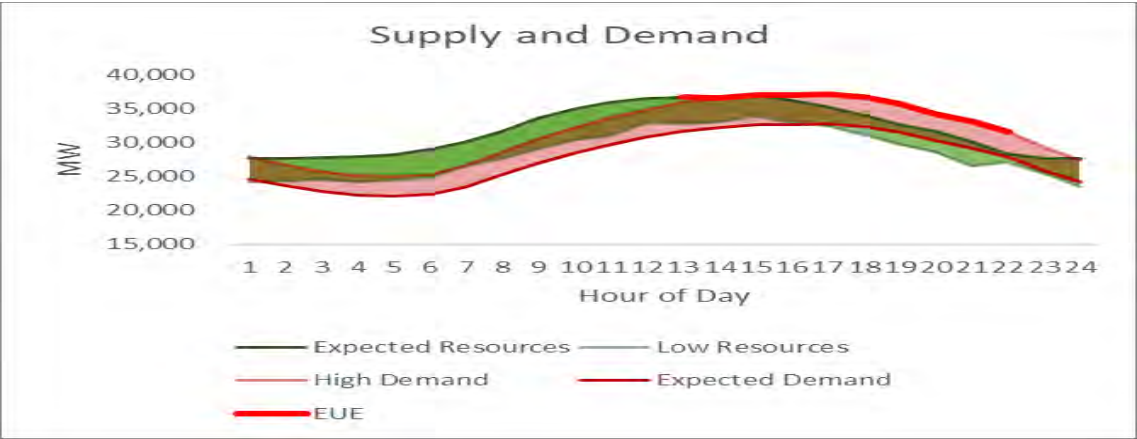
NPCC New York Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	1.909	0.466	12.478
NEUE (ppm)	0.012	0.003	0.078
LOLH (hours per Year)	0.011	0.002	0.035
* Provides the 2024 ProbA results for Comparison			

EUE Heat Maps – 2029

Negligible risk presented for Summer 2029, with occurrences clustered in July and August around hours 16 to 18.

Month	Hour																							
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	7%	24%	25%	7%	3%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	8%	16%	6%	1%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Hourly demand and resource projections for the highest EUE day in 2029 are shown in the figure below.



Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the higher net demand levels from LFU compounded with a greater risk added due to the variability in resource contribution. The higher net demand LFU levels could be 10–13% higher than expected, which could strain the system as modeled in the ProbA.

Demand

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

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

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

The 10-year annual average energy (+1.7%) and summer peak demand (+1.0%) growth rates are similar to last year’s forecast. Throughout the 30-year forecast period, baseline energy and seasonal peak demand increase significantly due to New York State electrification and decarbonization policies, principally the CLCPA. The baseline forecast includes significant electrification via conversion to electric heating and electric non-weather sensitive appliances, along with significant growth in EV adoption. In the early forecast years, large-load projects add significant growth to the annual energy and peak demand forecasts. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO has been working on developing market concepts to encourage the participation of flexible load, which participation will become increasingly important as the levels of weather-dependent intermittent resources on New York’s grid increase in response to the state’s climate and clean energy

policies. New York utilities are piloting several load management programs (e.g., smart electric vehicle charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO’s annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

For the 2025 LTRA, the DR participation for the summer capability period has increased slightly from 1,294 MW to 1,487 MW. These values are nameplate and are derated for reserve margin calculations. For example, the 1,487 MW is derated to 989 MW. There are currently 433 MW of DR participating in ancillary services programs (not included in reserve margin calculations) and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

In 2024, NYISO implemented a plan to integrate DERs, including DR resources, into its markets. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single-participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

Generation

Significant new resource development will be required to achieve New York’s energy targets under the CLCPA. According to the [2023–2042 System and Resource Outlook](#) the total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply and meet policy requirements within the next 20 years.

Currently, NYISO’s interconnection process⁴¹ contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

⁴¹ <https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx>

Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. The New York system relies on fossil-fuel, synchronous generation. ERSs usually provided to the system by synchronous fossil generation will remain necessary. As New York’s public policies seek to decarbonize the grid, fossil-fuel, synchronous generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFRs, will likely be part of this transformation.

On June 23, 2025,⁴² New York’s governor directed the New York Power Authority to develop and construct a zero-emission advanced nuclear power plant in upstate New York to support a reliable and affordable electric grid while providing the necessary zero-emission electricity to achieve a clean energy economy.

Energy Storage

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

Capacity Transfers

The models used for NYISO’s reliability planning studies include firm capacity transactions (purchases and sales) with its neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO limits emergency assistance from neighboring systems by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighboring systems.

⁴² <https://www.governor.ny.gov/news/governor-hochul-directs-new-york-power-authority-develop-zero-emission-advanced-nuclear-energy>

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York’s imports and exports of energy could vary significantly due to the resulting changes in neighboring systems. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York’s and other regions’ grids evolve, continuous monitoring and collaboration with our neighboring systems will be required.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City, and
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new ac tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030
- Con Edison’s proposed Brooklyn Clean Energy Hub project, including a new 345 kV load-serving substation with the goal of addressing local electric reliability needs in the boroughs of Brooklyn and Queens as well as the goal of serving as a point of interconnection for new clean-energy resources

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emission-free resources while maintaining the reliability of New York’s electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state’s electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York’s clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC’s consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

NYISO’s *2024 Reliability Needs Assessment*⁴³ (RNA) and subsequent analysis⁴⁴ identified very tight transmission security margins in New York City (Zone J) by 2034. The narrowing of the reliability margin continues to be a major concern. Most recently, NYISO’s 2025 Quarter 3 STAR report⁴⁵ identified short-term reliability needs in New York City and Long Island due to generation deactivations.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York’s current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system’s balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

⁴³ <https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf>
⁴⁴ https://www.nyiso.com/documents/20142/51270164/CRP_KeyTopics_TPAS_050625.pdf
⁴⁵ NYISO’s 2025 Q3 STAR Report: <https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf> and Explanatory Statement:

[https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.p](https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf)
df; Solutions Solicitation: <https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf>

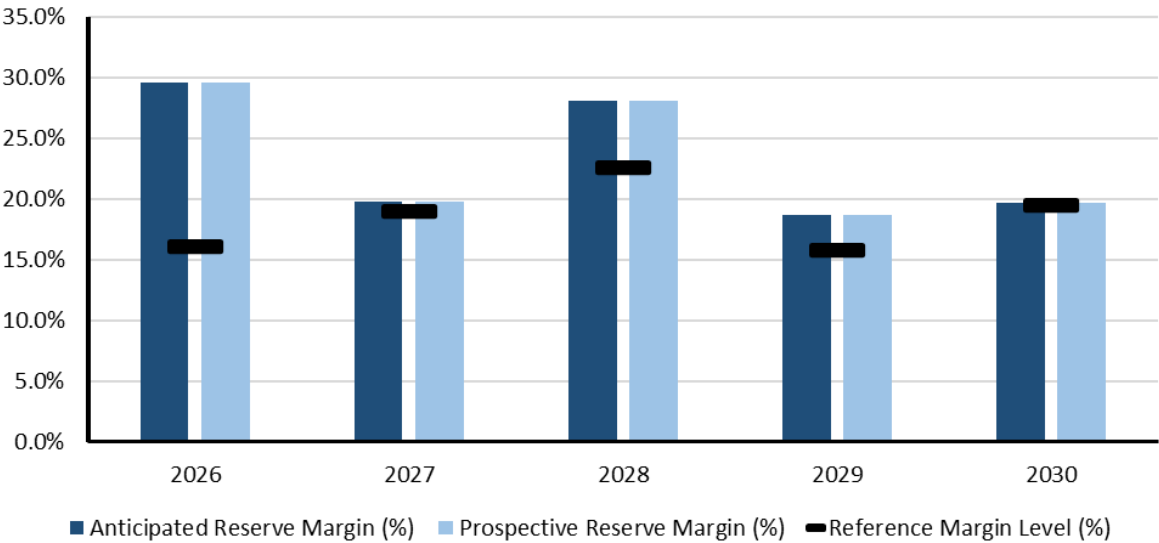


NPCC-Ontario

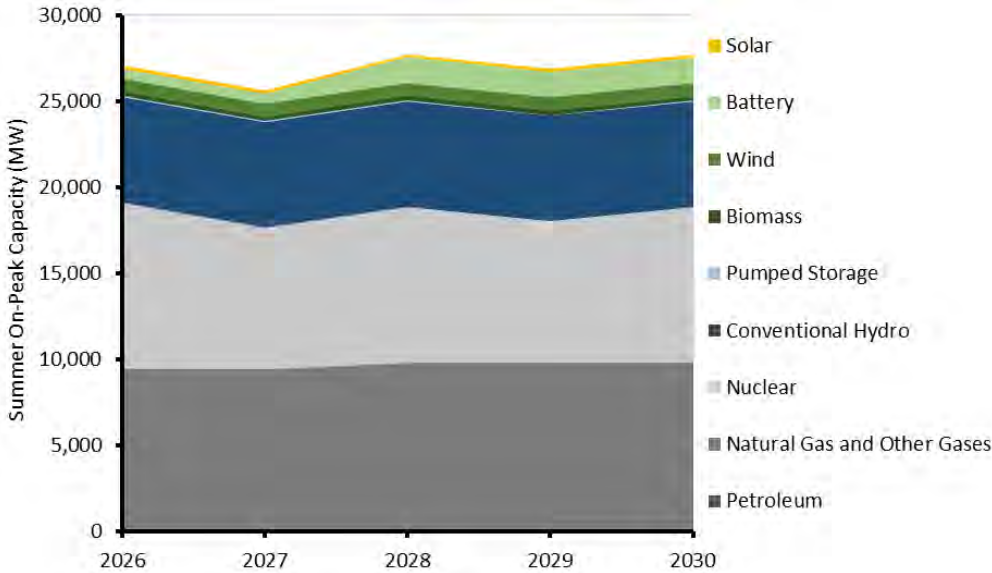
NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for 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.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	23,403	24,023	24,514	25,587	26,443	26,927	27,747	28,621	29,202	29,974
Demand Response	2,046	1,998	2,090	2,092	2,093	2,095	2,096	2,098	2,099	2,101
Net Internal Demand	21,357	22,025	22,424	23,495	24,350	24,832	25,651	26,523	27,103	27,873
Additions: Tier 1	853	853	2,156	2,156	2,156	2,964	3,507	4,051	4,579	5,387
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	600	600	600	1,233	1,324	1,324
Net Firm Capacity Transfers	602	772	1,002	1,002	1,432	1,002	302	302	302	302
Existing-Certain and Net Firm Transfers	26,833	25,541	26,577	25,737	26,999	25,623	25,767	25,767	26,611	26,611
Anticipated Reserve Margin (%)	29.6%	19.8%	28.1%	18.7%	19.7%	15.1%	14.1%	12.4%	15.1%	14.8%
Prospective Reserve Margin (%)	29.6%	19.8%	28.1%	18.7%	19.7%	15.1%	14.1%	12.4%	15.1%	14.8%
Reference Margin Level (%)	16.1%	19.0%	22.6%	15.8%	19.5%	13.9%	14.7%	9.6%	14.3%	13.2%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Ontario Highlights

- Ontario’s ARMs remain above the RML for the first five years of the 2025 LTRA outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030.
- Ontario’s 2025 Annual Planning Outlook (APO) identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. Different to last year’s LTRA, the IESO assumes generation resources are expected to be re-contracted (through the IESO’s reacquisition mechanisms) after those contracts expire. This has improved the resource outlook for the IESO when compared to last year while aligning the methodology to forecast supply with the methodology used by other NERC assessment areas.
- For demand, Ontario projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. As a result, total internal demand is projected to grow by 31% over the next 10 years to nearly 30 GW by 2035.
- Ontario’s generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. Ontario’s planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed procurements to re-contract existing resources.
- Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW (installed capacity) of BESS to come on-line, with discharge durations of four hours.
- Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Petroleum	3	3	3	3	3
Natural Gas	9,385	9,385	9,790	9,790	9,790
Biomass	299	304	310	310	310
Solar	150	150	150	150	150
Wind	724	725	728	732	732
Conventional Hydro	6,163	6,163	6,163	6,163	6,163
Pumped Storage	38	38	38	38	38
Nuclear	9,724	8,256	9,059	8,214	9,047
Battery	597	597	1,489	1,489	1,489
Total MW	27,084	25,622	27,731	26,891	27,723

NPCC-Ontario Assessment

Planning Reserve Margins

Ontario’s ARMs remain above the RML for the first five years of the 2025 LTRA outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030. No Tier 2 resources have been identified for this year’s publication.

The IESO calculates Ontario’s reserve margin annually using the GE MARS model and applies a more stringent reserve criterion than the NPCC standard of 0.1 days/year LOLE, incorporating additional reserves to manage risks associated with nuclear refurbishments and new nuclear builds. For example, over the LTRA outlook, the 2025 Annual Planning Outlook (APO) includes reserves of nearly 800 MW in some summers and nearly 1,100 MW in some winters to account for uncertainties in nuclear project timelines. If these additional reserves were excluded, Ontario would meet or exceed the RML in all years of the assessment. MARS inputs include resource availability, outages, refurbishment schedules, interface limits, and demand uncertainty. The model uses probabilistic simulations and Monte Carlo analysis for wind and solar and historical data for hydro and thermal units. The assessment evaluates system adequacy across all hours, not just peak periods.

For the 2025 LTRA, the IESO applied NERC’s definitions for Tier 1 and Tier 3 resources. The IESO’s Resource Adequacy Framework (RAF) enables reacquisition of existing resources nearing contract expiry. It’s important to distinguish between off-contract resources and those that have reached end of life or retired. Many existing Ontario resources remain operational and can be upgraded or re-contracted, with the RAF providing competitive mechanisms to secure capacity from these resources. The 2025 LTRA assesses reliability independent of contractual status, unlike the 2025 APO, which aims to determine the resource adequacy needs in order to inform future reacquisitions of existing and new resources. As a result, the 2025 LTRA outlook will differ from the 2025 APO, especially regarding off-contract resources that are likely to continue to be operational.

The RAF remains unchanged since the 2024 LTRA and continues to guide the reacquisition of existing resources and the procurement of new capacity. The RAF supports a flexible, multi-pronged approach to resource adequacy, including capacity auctions, medium- and long-term procurements, and targeted programs for re-contracting or upgrading existing facilities and securing new resources.

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

Ontario conducts annual energy adequacy assessments using Energy Exemplar’s Plexos software, which models the province’s nodal transmission network and simulates dispatch under expected

system conditions. These deterministic assessments evaluate energy sufficiency over a 20-plus-year horizon and are supplemented by sensitivity analyses to identify periods of heightened risk.

The 2025 APO identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. It should be reinforced that the APO presents an energy adequacy assessment used to inform future procurements, whereas the LTRA’s purpose is to inform reliability of the system, where contractual end dates are not incorporated into the assessment

Shorter-term energy assessments are conducted quarterly through the Reliability Outlook (RO), which evaluates energy adequacy over an 18-month horizon. These assessments use probabilistic demand forecasts and outage data to identify seasonal and weekly risks. While the RO time frame is too short to secure new resources, the IESO uses operational tools such as capacity auctions, coordination with market participants on outage scheduling, and DR programs to mitigate risks.

Ontario’s energy adequacy assessments do not assume economic imports or exports, reflecting a self-sufficiency planning approach. However, in practice, intertie capacity and capacity-sharing agreements (e.g., with Hydro-Québec) provide additional flexibility during periods of stress.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0.043	0.001	0.066
NEUE (ppm)	0.000	0.000	0.000
LOLH (hours per Year)	0.000	0.000	0.000
*Provides the 2024 ProbA Results for Comparison			

Demand

Ontario’s demand forecast is shaped by a combination of econometric modeling for the near-term and sectoral/end-use modeling for the long term. The 2025 APO projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. Growth projections in the 2024 LTRA were 2.34% for summer and 2.75% for winter. Marginal increases in demand growth since the 2024 LTRA are attributed to data center growth and EV production. Incremental 2025 APO forecasted growth is driven by the following:

- Electrification of buildings, transportation, and industry
- Expansion of electric vehicle (EV) production and supply chains

- Rapid development of commercial data centers
- Population growth and household formation

Offsetting factors include increased EE, DSM programs, and a plateau in agricultural greenhouse expansion.

The 2025 APO forecasted Ontario to become a dual-peaking jurisdiction by 2030, with winter and summer peaks converging due to increased electrification of heating. The IESO’s demand forecast incorporates updated assumptions on immigration, economic growth, and sector-specific developments, including hydrogen production, steel decarbonization, and data center expansion. Additional large loads in planning but not yet included in the forecast are assessed based on their development stage, funding, and likelihood of materialization.

Ontario anticipates significant changes in load behavior, including increased demand from building electrification, EV charging (shifting peaks), data centers, hydrogen electrolyzers, and large industrial loads. These trends introduce variability and new reliability challenges. The IESO conducts [System Impact Assessments \(SIA\)](#) for large loads, evaluating impacts such as voltage flicker and transient stability. Enhancements to the assessment process are underway. Additionally, annual regulation needs assessments project up to 110 MW of incremental regulation by 2035 to manage fluctuating loads, with procurement strategies in place to meet these needs.

Demand-Side Management

The IESO has implemented a capacity qualification process that applies performance-based derates to DR resources, ensuring more reliable capacity contributions. Since the 2024 LTRA, the [Peak Perks program](#) has expanded to small businesses, helping the program deliver more than 152 MW of summer peak demand reduction in 2024, growing to over 200 MW in 2025. A new DR program targeting HVAC loads in the commercial and institutional sector is in development. These programs, as well as the [Industrial Conservation Initiative \(ICI\)](#), also contribute to peak demand reduction. A new electric demand side management (eDSM) framework spanning the next 12 years commenced with a \$1.8 billion budget for years 2025–2027 targeting 4.6 TWh of energy savings and 900 MW of peak demand savings.

Distributed Energy Resources

Ontario’s DER landscape includes both contracted embedded generation and uncontracted BTM resources. In 2024, contracted DERs totaled over 3,400 MW, with about 60% from solar, 20% from wind, and 15% from hydro and biomass. Uncontracted DERs contributed an estimated 2.7 TWh of energy.

DERs are integrated into planning through the [Enabling Resources Program \(ERP\)](#), which is developing participation models for standalone DERs, hybrid resources, and aggregations. The IESO is also advancing coordination protocols through the Transmission-Distribution Coordination Working Group (TDWG), which has proposed tools for real-time coordination and visibility. The group wrapped up work during Summer 2025 and has posted final reports on their findings.

DERs are considered in transmission planning as non-wires alternatives and are increasingly included in regional planning processes. The IESO’s [DER Potential Study](#) and Local Generation Program aim to further integrate DERs into Ontario’s RAF.

Generation

Ontario’s generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. To maintain system reliability, the IESO continues to monitor key operational parameters such as primary frequency response and system inertia, both of which are currently sufficient but require reassessment as the resource mix evolves. Ramping needs can be provided by over 11,100 MW of natural gas generation with 600 MW able to be online and ramp within 20 minutes. Supply to the majority of Ontario’s gas fleet is robust and supported by significant firm supply and transportation contracts. The IESO does not expect any material gas supply or delivery issues under extreme winter conditions. The day-ahead market, established through the IESO’s [Market Renewal’s](#) Program, allows for firm gas supply to be scheduled.

Deliverability testing is a core component of Ontario’s long-term procurement process, ensuring that new resources can connect without causing congestion or reliability issues. For the IESO’s second long-term procurement, testing will be expanded to include inverter-based resource screening for sub-synchronous control interactions.

Ontario has updated its Market Rules to align with IEEE 2800 and now requires synchrophasor data from generators and transmitters to improve situational awareness and IBR performance. The IESO is also conducting system-wide electromagnetic transient (EMT) studies and validating models for battery storage projects to proactively address sub-synchronous control interaction risks.

For Ontario’s adequacy assessments, capacity contribution values for thermal resources are calculated using historical performance and probabilistic modeling. Wind and solar contributions are based on seasonal capacity factors, while hydroelectric values are derived from historical output. Energy storage contributions are based on a four-hour discharge duration.

Ontario’s planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed medium-term procurements, which re-contracted existing resources for five-year terms. In addition to medium-term procurements, the IESO also maintains mechanisms such as Reliability Must Run agreements and capacity auctions to mitigate retirement risks. The IESO is currently conducting assessments for operating reserve and frequency response for the next 10 years, intended to be included in the 2026 APO.

Overall, Ontario’s generation planning is increasingly focused on flexibility, resilience, and integration of emerging technologies, with a strong emphasis on ensuring deliverability, maintaining operability, and adapting to evolving reliability challenges.

Energy Storage

Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW of new BESS to come on-line, with discharge durations of four hours. These resources were secured through the Expedited Long-Term 1 (E-LT1) and LT1 procurements.

New storage projects may also participate in the second long-term procurement and long-lead time procurement, which aim to support system reliability during periods of high demand and low renewable output, particularly in the 2029–2035 time frame.

Energy storage resources are currently modeled as generators and loads at the same location, which presents operational challenges. The IESO is working to enhance its market tools and participation models through the ERP, which includes co-located and hybrid resource integration. Storage resources are also being incorporated into resource adequacy assessments using GE MARS software, which optimizes dispatch and accounts for energy reservoir size.

While operational experience with transmission-connected storage is still limited, the IESO is actively monitoring performance and refining planning assumptions. The integration of nearly 3 GW of new storage capacity over the next four years is expected to significantly improve Ontario’s ability to manage variability and meet ramping needs.

Capacity Transfers

Ontario maintains robust intertie connections with neighboring jurisdictions, including Québec, New York, Michigan, Manitoba, and Minnesota. These interconnections play a critical role in supporting reliability, particularly during peak demand periods and resource shortfalls.

Two key capacity swap agreements with Hydro-Québec provide Ontario with firm summer capacity. The [2016 agreement](#) allows for a 500 MW swap, while the [2024 agreement](#) enables a 600 MW per year exchange over a seven-year period. These agreements are designed to be flexible, allowing Ontario to bank capacity and use it in future summers as needed.

Ontario’s planning assessments assume self-sufficiency for the purpose of reserve margin calculations. However, in practice, these intertie agreements provide a valuable reliability backstop. The IESO coordinates closely with Hydro-Québec to align assumptions and ensure deliverability across the interties.

The refurbishment of Pickering NGS as well as new small modular reactors (SMR) scheduled to come on-line in the 2030s necessitated the review of flows across the province to maintain reliable operations. As a result, several new transmission projects have been proposed.

The IESO also participates in regional and interregional transmission planning processes, including NPCC area Transmission reviews and NERC planning assessments. These reviews ensure that Ontario’s transmission system can support capacity transfers and maintain reliability under a range of scenarios.

Firm capacity transfers have appeared to increase in this LTRA publication compared to 2024 due to a review of NERCs definitions, allowing modeled and coordinated capacity to be treated as firm. This process aligns with the IESO’s internal studies.

Transmission

Ontario is undertaking a significant expansion of its transmission system to support growing demand, resource integration, and system reliability. Key projects include the Waasigan Transmission Line, Etobicoke Greenway, and Flow East Towards Toronto (FETT) upgrade, which will collectively enhance capacity and resilience across the province. Additional reinforcements in London, Windsor-Essex, and northeastern Ontario address regional growth and industrial development. Voltage support devices, such as shunt reactors and STATCOMs, are being deployed to manage high voltages and support new transmission lines.

Transmission planning studies have identified constrained areas, particularly in the Greater Toronto Area (GTA), Essa (Barrie area), and eastern Ontario. These constraints are being addressed through the South and Central Ontario Bulk Plan and corridor studies to secure future transmission routes.

The IESO is also planning a new 500 kV double-circuit transmission line from Bowmanville to Toronto to support the connection of SMRs at Darlington NGS. This line is expected to be in service by the early 2030s.

To streamline transmission development and integrate Tier 2 resource deliverability insights, the IESO is designing a [Transmitter Selection Framework \(TSF\)](#) and enhancing its evaluation of non-wires alternatives (NWA). These initiatives aim to accelerate project delivery and improve coordination among stakeholders.

Reliability Issues

Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. The IESO is actively monitoring these trends and has published technical papers to better understand their implications. SIAs are conducted for large loads to evaluate impacts on voltage, stability, and power quality, with future enhancements planned to address sub-synchronous oscillation and ramp rate concerns.

Interdependencies with critical infrastructure sectors—such as natural gas, telecommunications, and transportation—are also being assessed. Ontario’s gas supply is considered robust, with most generators located near the Dawn storage hub and supported by firm contracts. Dual-fuel capabilities of some generators and coordination protocols with gas pipeline operators further mitigate risks during extreme weather. The IESO’s Market Renewal Program enhances gas-electric coordination through improved day-ahead scheduling.

Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments. Emerging technologies like battery storage and SMRs also present integration challenges. To address these, Ontario’s planning processes prioritize flexibility, resilience, and proactive mitigation strategies, including outage planning that accounts for extreme weather scenarios.

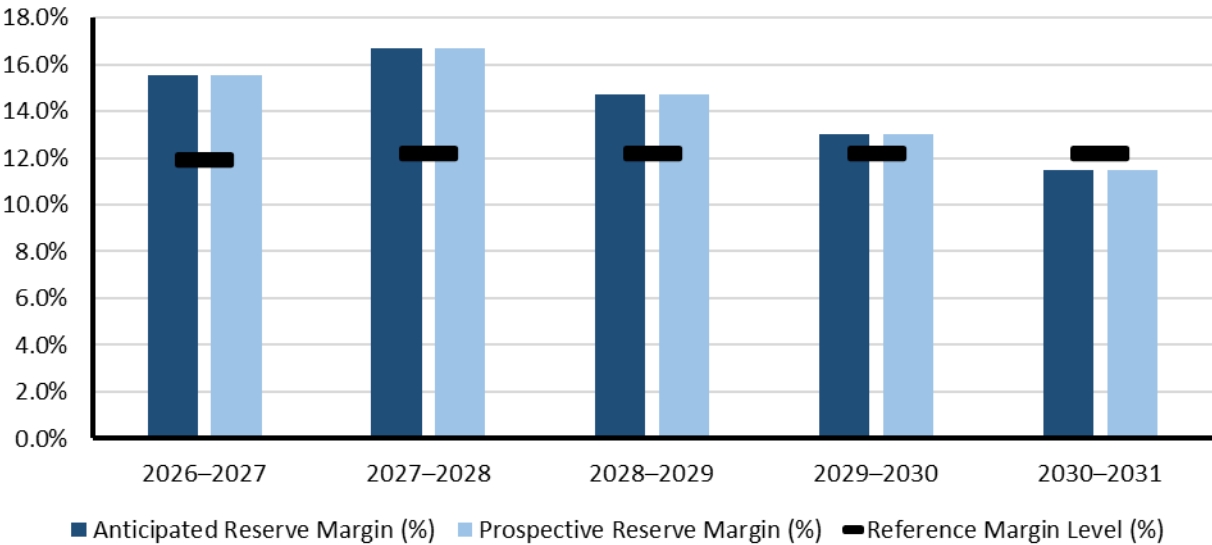


NPCC-Québec

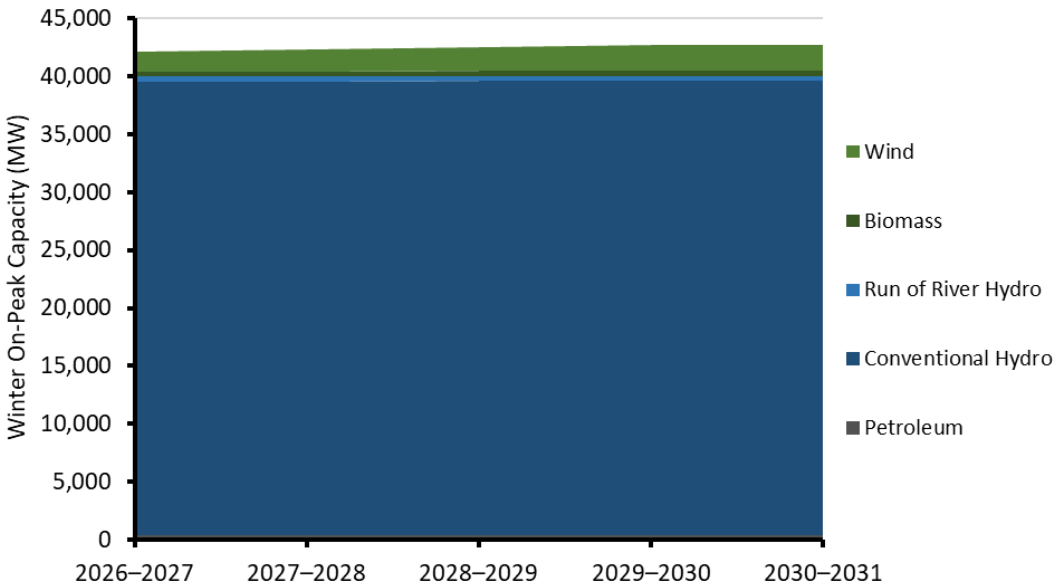
NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the 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.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	41,405	41,901	42,833	43,635	44,392	45,116	46,053	47,148	48,164	49,613
Demand Response	5,058	5,224	5,367	5,445	5,533	5,587	5,618	5,606	5,562	5,562
Net Internal Demand	36,347	36,677	37,465	38,191	38,859	39,529	40,435	41,542	42,602	44,051
Additions: Tier 1	412	566	710	891	891	891	891	891	891	891
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-145	455	455	455	600	0	0	0	0	0
Existing-Certain and Net Firm Transfers	41,591	42,231	42,269	42,272	42,421	41,825	41,830	41,834	41,838	41,842
Anticipated Reserve Margin (%)	15.6%	16.7%	14.7%	13.0%	11.5%	8.1%	5.7%	2.9%	0.3%	-3.0%
Prospective Reserve Margin (%)	15.6%	16.7%	14.7%	13.0%	11.5%	8.1%	5.7%	2.9%	0.3%	-3.0%
Reference Margin Level (%)	11.9%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Québec Highlights

- ARMs remain above the RML for the first four years of the assessment period.
- Over 4,000 MW of new wind installed capacity is expected to be in service by 2030, with additional wind projects in development.
- Hydro-Québec’s Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and gas-fired generation. These projects are not included in Tier 1–3 categories in the present assessment due to their early development stage or ongoing stakeholder consultations but are expected to be incorporated gradually into future assessments.
- Major transmission projects, including the Appalachaches–Maine (NECEC) and Hertel–New York (CHPE) interconnections, are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Petroleum	429	429	429	429	429
Biomass	405	405	405	405	405
Wind ⁴⁶	1,778	1,931	2,076	2,257	2,257
Conventional Hydro	39,091	39,129	39,167	39,170	39,175
Run of River Hydro	445	447	447	447	447
Total MW	42,148	42,342	42,524	42,708	42,712

⁴⁶ Expected at-peak capacity.

NPCC-Québec Assessment

Planning Reserve Margins

ARMs remain above the RML for the first five winters of the assessment period (2025–26 to 2029–30), supported by existing and anticipated capacity and firm imports. Margins fall below the RML starting in 2030–31 due to sustained demand growth from electrification. Several large-scale projects are under development but are not included in the reserve margin calculation due to their early-stage status. The RML is based on the 2024 NPCC Interim Review of Resource Adequacy and accounts for weather and economic uncertainty, generator outages, and DR constraints.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2024 Supply Plan update, which was filed with the Régie de l’énergie on November 1, 2024, and the 2024 Québec Interim Review of Resource Adequacy filed with the NPCC in December 2024.

Over 90% of Québec’s installed capacity comes from large hydroelectric reservoirs, enabling flexible and reliable energy delivery. The system is designed to withstand multi-year droughts, with planning criteria requiring sufficient reserves to cover inflow deficits of 64 TWh over two years and 98 TWh over four years. No off-peak or seasonal energy risks have been identified.

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

Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, the EUE is 62.99 MWh with an expected LOLE of 0.106 hours per year.⁴⁷

ProbA Summary of Results			
	2026*	2027-2028	2029-2030
EUE (MWh)	8.205	0.01	62.99
NEUE (ppm)	0.040	0.000	0.29
LOLH (hours per Year)	0.014	0.000	0.11
*Provides the 2024 ProbA Results for Comparison			

Demand

Québec’s demand forecast is driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data

centers are also contributing to demand growth. Forecasts are developed using sector-level modeling and include high and low scenarios to reflect uncertainty.

Demand-Side Management

Hydro-Québec operates a broad portfolio of DR programs, including interruptible load contracts for industrial and commercial customers, and smart heating and dynamic pricing for residential users. These programs are expected to provide 5,600 MW of peak reduction by 2034–2035. Reported capacities reflect actual observed reductions during events. EE and conservation programs are integrated into demand forecasts.

Distributed Energy Resources

BTM solar PV is expected to reach 705 MW by 2035. However, due to Québec’s winter-peaking profile, the on-peak contribution of DERs remains below 5 MW. No operational impacts are expected, and no DER aggregators are currently active in the area.

Generation

4,000 MW of wind installed capacity is under development or construction, including the Apuiat project (204 MW), three 400 MW phases of Des Neiges, and two procurement rounds totaling 2,700 MW. Hydro-Québec is also pursuing:

- Up to 2,000 MW from hydro unit upgrades;
- 5,000 MW of wind installed capacity through new community partnerships;
- 3,440 MW from Churchill Falls upgrades and the Gull Island project;
- 3,000 MW of solar installed capacity by 2035, including 300 MW of front-of-the-meter PV by 2029;
- Potential battery storage and natural gas generation.

Except for the 4,000 MW of wind capacity in construction, these projects are not included in the Tier 1–3 categories due to their early development stage or ongoing stakeholder consultations.

Energy Storage

No energy storage resources are currently planned for commissioning during the assessment period.

⁴⁷ 2025 Probabilistic Assessment results cover the period from March of the first year to February of the second year.

Capacity Transfers

Québec maintains firm seasonal capacity exchange agreements with Ontario (600 MW imports in winter, exports in summer). Québec has several firm capacity export agreements during the summer season.

Transmission

Hydro-Québec plans to add 5,000 km of new transmission lines and several major substations by 2035 to support regional development and renewable integration. Key projects include the following:

- NECEC (1,200 MW to Maine) – expected in service by December 2025
- CHPE (1,250 MW to New York) – expected in service by May 2026
- Three new 735 or 315 kV corridors in Québec
- Jean-Jacques-Archambault substation – planned for 2029

No long-term transmission constraints have been identified.

Reliability Issues

Large industrial loads are screened and approved by the Québec government and Hydro-Québec based on available supply. A moratorium is in place for new blockchain clients. The system’s winter peak is primarily driven by residential heating, and industrial additions are not expected to significantly affect peak uncertainty. To mitigate the impact of rising demand, Hydro-Québec is expanding its DSM programs and studying multiple new generation projects. In addition, Québec’s large hydro reservoirs provide strong protection against the impacts of drought. The system is planned to meet a regulatory energy reliability criterion requiring sufficient reserves to withstand inflow deficits of 64 TWh over two years and 98 TWh over four years.

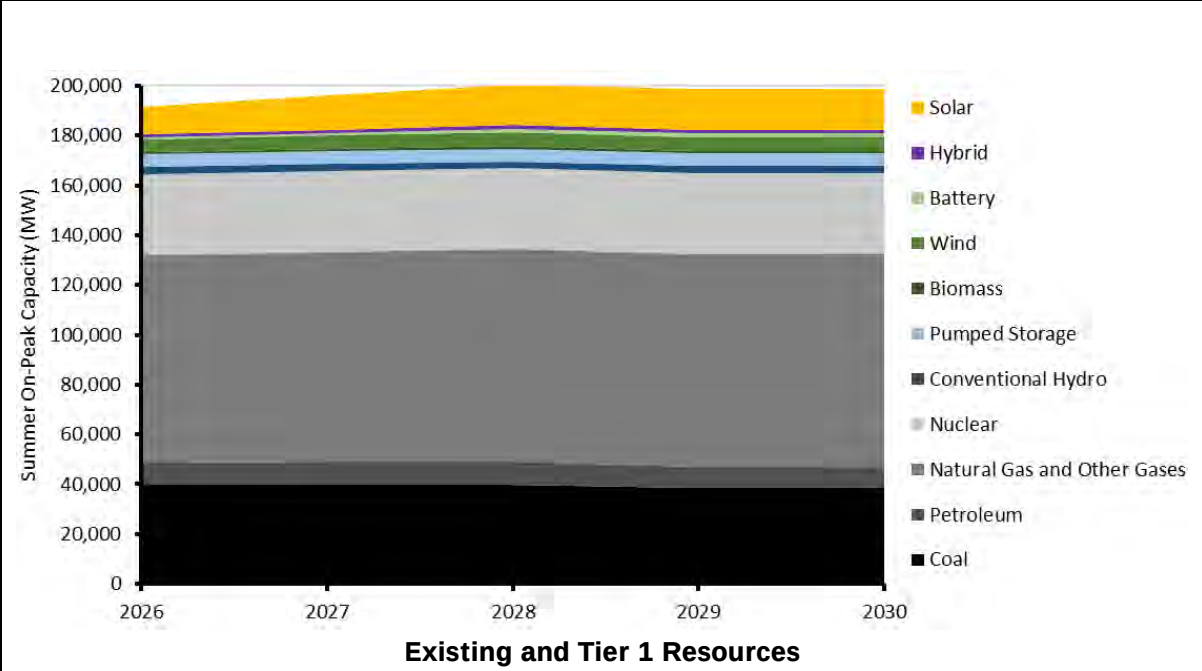
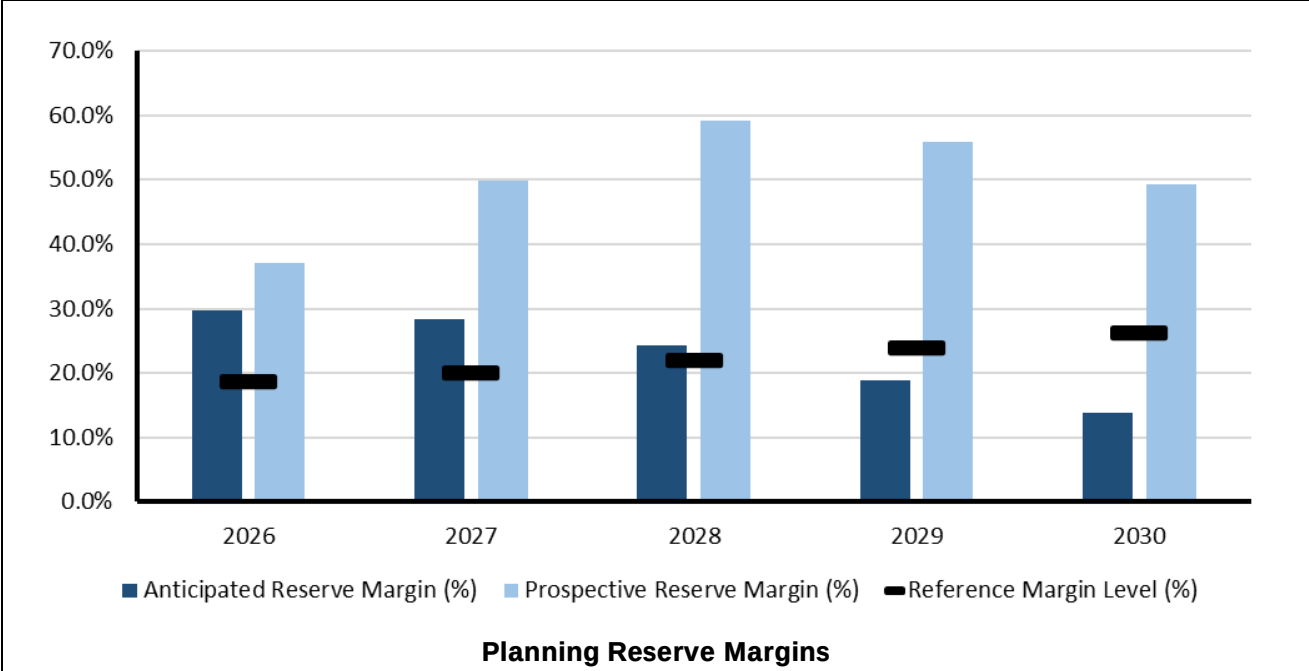


PJM

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 has an approximate population of 67 million people. PJM is the area’s BA, Transmission and Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	158,937	164,186	169,981	176,094	183,883	192,647	200,507	204,197	207,253	209,923
Demand Response	8,184	8,439	8,703	9,002	9,398	9,845	10,250	10,409	10,533	10,629
Net Internal Demand	150,753	155,747	161,278	167,092	174,485	182,802	190,257	193,788	196,720	199,294
Additions: Tier 1	5,861	10,177	14,521	14,709	14,709	14,709	14,709	14,709	14,709	14,709
Additions: Tier 2	12,410	38,519	65,315	71,119	75,116	75,290	77,655	77,655	77,655	77,655
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	3,840	3,818	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	189,693	189,644	186,005	184,030	184,030	184,030	184,030	184,030	184,030	184,030
Anticipated Reserve Margin (%)	29.7%	28.3%	24.3%	18.9%	13.9%	8.7%	4.5%	2.6%	1.0%	-0.3%
Prospective Reserve Margin (%)	37.0%	49.9%	59.1%	55.9%	49.3%	42.6%	27.7%	25.4%	23.5%	20.0%
Reference Margin Level (%)	18.6%	20.1%	21.9%	23.9%	26.3%	28.9%	30.8%	33.0%	35.1%	35.1%



PJM Highlights

- Load forecasts have increased year over year due to data center and economic growth as well as increased electrification in the PJM footprint.
- Available generation capacity has decreased due to retirements and delays in new additions to the fleet.
- Based on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.
- PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid/minimize the need for emergency procedures.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	39,866	39,866	39,866	38,288	38,288
Coal*	39,866	37,738	27,448	28,002	26,464
Petroleum	8,952	9,163	9,163	8,766	8,766
Natural Gas	83,210	84,150	85,385	85,385	85,385
Natural Gas*	82,589	83,443	84,678	84,678	84,678
Biomass	857	907	907	907	907
Solar	11,282	13,616	16,141	16,328	16,328
Wind	5,251	5,496	5,622	5,622	5,622
Conventional Hydro	2,807	2,829	2,829	2,829	2,829
Pumped Storage	5,068	5,068	5,068	5,068	5,068
Nuclear	32,508	32,508	32,508	32,508	32,508
Hybrid	1,187	1,504	1,504	1,504	1,504
Battery	703	895	1,531	1,531	1,531
Total MW	191,712	196,002	200,524	198,737	198,737
Total MW*	191,091	193,166	187,399	187,743	186,205
*Capacity with additional generator retirements. Generators that are forecasted to retire by PJM are removed from the resource projection where marked.					

PJM Assessment

Planning Reserve Margins

The PJM ARM falls below the Installed Reserve Requirement (RML) in 2029 when the ARM dips just below 19% as the RML reaches 24%.

- Accelerated retirements, driven by unit age and environmental public policy, of generators that provide necessary attributes needed to maintain reliability are outpacing new, mainly IBR additions. PJM received over 30 deactivation notifications totaling over 2 GW in 2024.
- Approximately 40% of new interconnection requests to the PJM grid are solar resources.

PJM faces an extreme and rapid tightening of supply and demand for capacity resources in the near term and needs additional resources to rapidly address its near-term reliability challenges.

PJM is in a transition year as the determination is based on the Reserve Requirement Study (RRS) and Effective Load Carrying Capability (ELCC) Study via PJM Manual 20A Resource Adequacy Analysis.⁴⁸

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

Based on the load increase and generation decrease, PJM is projecting a potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.

PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid or minimize the need for such emergency procedures. The greatest risk is still during the summer peak period.

Probabilistic Assessments (NERC ProbA and Other Studies)

LOLH and EUE values for 2027 are 0.61 hours/year and 3,251 MWh/year, respectively, which are values consistent with PJM having a 2027 LOLE slightly worse than the 1 day in 10-year target. For 2029, the metrics significantly increase (LOLH = 9.97 hours/year and EUE = 67,581 MWh/year) due to significant forecasted peak load increases (i.e., more than 12,000 MW in summer and more than 14,000 MW in winter, driven by large load additions in the PJM footprint) and the changing resource portfolio mix (i.e., the retirement of thermal resources and the addition of wind, solar and storage, that do not provide an expected commensurate resource adequacy value when compared to the retired thermal resources).

In both studied years, large shares of the annual EUE and LOLH are concentrated in the winter months (especially January). In such winter days, the loss-of-load events identified by the model are driven by low temperatures, which result in high loads and the potential for high correlated outages from gas resources as well as poor performance from solar resources. These winter events tend to occur during both morning and evening peaks.

The smaller shares of EUE and LOLH observed in the summer period for 2027 and 2029 are driven by events in the evening (hours ending 19 and 20), during days with high temperature, high loads, and declining performance of BTM and front-of-the-meter solar resources, low performance of wind resources, and to a lesser extent by slightly worse performance of thermal resources.

The ProbA results differ from the LTRA results in that the ProbA models the following:

- Fewer additions: Resources that are identified as Tier 1 in the LTRA may not reach the in-service status on their targeted in-service date.
- More retirements: The current number of announced retirements does not reflect all the environmental policies that states in the PJM footprint are targeting for future years.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	538	3,251	67,580
NEUE (ppm)	0.00	3.50	65.50
LOLH (hours per Year)	0.11	0.61	9.97
* Provides the 2024 ProbA Results for Comparison			

Demand

The demand for electricity is growing at the fastest pace in years, primarily from the proliferation of data centers, electrification of buildings and vehicles, and manufacturing.

PJM expects its summer peak to climb by 55,779 MW to 209,923 MW in 2035, while winter peaks are expected to grow by 62,048 MW to reach 198,175 MW by winter 2034–35.

Sector models are a key part of the load forecast process, providing insights into why load trends are happening. Sector models also incorporate the independent assumptions on economic trends and

⁴⁸ <https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.pdf>

end-use adoption and efficiency. The PJM load forecast process considers three sectors: residential, commercial, and industrial. Each sector has its own set of models and inputs.

The load forecast is constructed using 24 hourly models for each zone. In each model, load is the dependent variable. In the history, we start with metered load and then re-constitute with load management addbacks, load drops associated with peak shaving programs, load related to load adjustments (where applicable), and distributed solar generation estimates.

PJM’s projected load indicators in many instances have doubled from the 2024 LTRA projections. For example, net energy for load growth for PJM is projected to average 4.8%, up from 2.3% in last year’s projections, per year over the next 10-year period and 2.9% over the next 20 years. Total PJM energy is forecasted to be 1,328,045 GWh in 2035, a 10-year increase of 495,264 GWh, and reaches 1,482,068 GWh in 2045, a 20-year increase of 649,287 GWh. Annualized 10-year growth rates for individual zones range from 0.2% to 8.4% with a median of 1.6%.

Demand-Side Management

As in past years, DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during the summer peak season from 8,184 MW in 2026 to 10,629 MW in 2035. PJM’s probabilistic resource adequacy modeling accounts for observed DR availability variations by season and hour.

Distributed Energy Resources

PJM expects 4,810 MW of solar DERs at the time of summer peak demand in 2030 and 5,165 MW in 2035. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

PJM also expects 3,652 MW of contributions from plug-in EVs to load at the time of summer peak demand in 2030 and 8,250 MW in 2035, with additional contributions from distributed battery storage ranging from 300–900 MW over the same five-year period.

The net effect of DERs is included in the load forecast as the models utilize recent historical data, which implicitly include DERs.

Generation

PJM added 560 MW of new on-peak generation capacity since the 2024 LTRA. The new projects include one wind project at 24.5 MW and 19 solar projects totaling 535.5 MW. An additional 70 MW in capacity was connecting in late 2025.

Substituting thermal resources (coal, natural gas, and oil) with renewable generation (wind, solar, storage, and hybrid resources) may get significantly more challenging as the energy transition progresses and flexible thermal resources are still needed to maintain resource adequacy at one-in 10 LOLE.

Maintaining an adequate level of generation resources with the right operational and physical characteristics is essential for PJM’s ability to serve consumer demand through the energy transition. The composition and performance characteristics of the resource mix will ultimately determine PJM’s ability to maintain reliability. Today, thermal resources supply ERSs. Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability.

Increasing levels of intermittent resources create significant variability and uncertainty to be managed by flexible resources. If the gas fleet of today remains as is, or decreases due to regulatory pressures, but additional storage resources do not get built at pace, immense pressure will be placed on natural gas to supply the ramping needs for the system. Changes to market mechanisms will be evaluated to ensure that adequate resources are incentivized to help PJM manage increasing system uncertainty and volatility.

For example, in 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative, which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. PJM projects that the initiatives will boost Tier 1 resources by an additional 8.3 GW in summer periods and 3.4 GW in winter periods from the original 2025 LTRA data submittal.

Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original 2025 LTRA data submittal and 4.1 GW in winter capacity. These net increases factor resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

However, many of these projects continue to be slowed or stopped by factors that extend beyond PJM and affect multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges, and financing.

PJM uses some differing capacity assumptions between the LTRA and ProbA. The LTRA counts more resource additions, mainly new solar and gas combined-cycle units, which may not actually become operational. In contrast, the ProbA is more conservative, excluding some Tier 1 resources that might not reach the in-service date as planned. Additionally, the LTRA only accounts for officially announced

retirements, while the ProbA also factors in potential retirements caused by state environmental policies, particularly affecting coal resources projected to retire by 2029.

As of June 2025, all generation capacity resources, with the exception of VERs, that are committed in PJM’s Reliability Pricing Model or committed in a PJM Fixed Resource Requirement Plan shall be subject to operational testing initiated by PJM up to two times in each of the summer and winter seasons during the relevant delivery year. (Seasons are defined as: summer (May–October) and winter (November–April). Generation operational tests will be unannounced tests. The tests are being conducted to verify that generating resources can reliably operate when needed.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy DOE national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

There is approximately 162 GWs of solar, wind, battery and hybrid in the PJM interconnection queue requesting capacity injection rights. Hybrid resources make up approximately 20 GWs and standalone storage makes up approximately 40 GWs.

To address the limited-duration issue, some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or is hybrid (in which the storage facility and generator share a common connection to the grid).

Currently new storage is dispatched similar to other generators in economic order. No more specific operation has been considered due to the small penetration. Many older batteries are used for regulation.

Capacity Transfers

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

Transmission

Beginning in 2023, PJM began to identify trends encompassing large load increases in specific areas, driven primarily by the construction of new data centers, and these were incorporated in PJM’s 2024 RTEP cycle analyses for five-year (2029) and eight-year (2032) study year models. The large load increases are driving heavier, increased regional transfers and the consequent need for significant system reinforcement. PJM’s load forecasting process incorporates methods by which it solicits and applies large load adjustments by transmission zone. Electrification itself is the process of converting conventional end-use load that uses fossil fuels (e.g., gas stoves and oil-burning furnaces) to use electricity instead, as well as the increased use of EVs. This is having a significant impact on the magnitude of the load forecast and load shape. Notably, additional electric heating will narrow the gap between summer and winter peaks.

Most transmission additions are related to local load deliverability problems and not new generation enhancement in Tier 2. Each generator is responsible for transmission enhancements associated with its interconnection and network enhancements if necessary. PJM does not use Tier 3 resources.

PJM’s analysis of 2029 and 2032 summer, winter and light load conditions identified 8,520 thermal and voltage criteria flowgate violations across PJM, of which 1,609 were ineligible from competitive windows. The 6,911 remaining violations were addressed in 2024 RTEP Proposal Window No. 1

The large number of violations observed in the 2024 RTEP were driven by heavy west-to-east transmission interface flows caused by large load increases in the Dominion zone and in eastern PJM: 10 GW and 15 GW load increase for 2029 and 2032 between the load forecasts used for the 2022 and 2024 RTEP study cycles, respectively. The significant load growth is attributed primarily to data centers, electrification, and electric vehicle developments.

From PJM’s 2024 RTEP Proposal Window No. 1 (July–September 2024), 94 competitive proposals to solve the 6,911 NERC reliability criteria violations identified in the RTEP 2029 model year analysis as well as those identified in the 2032 model year requiring long-lead-time transmission solutions. The PJM board approved \$5.9 billion worth of regional and local projects to address the reliability criteria violations.

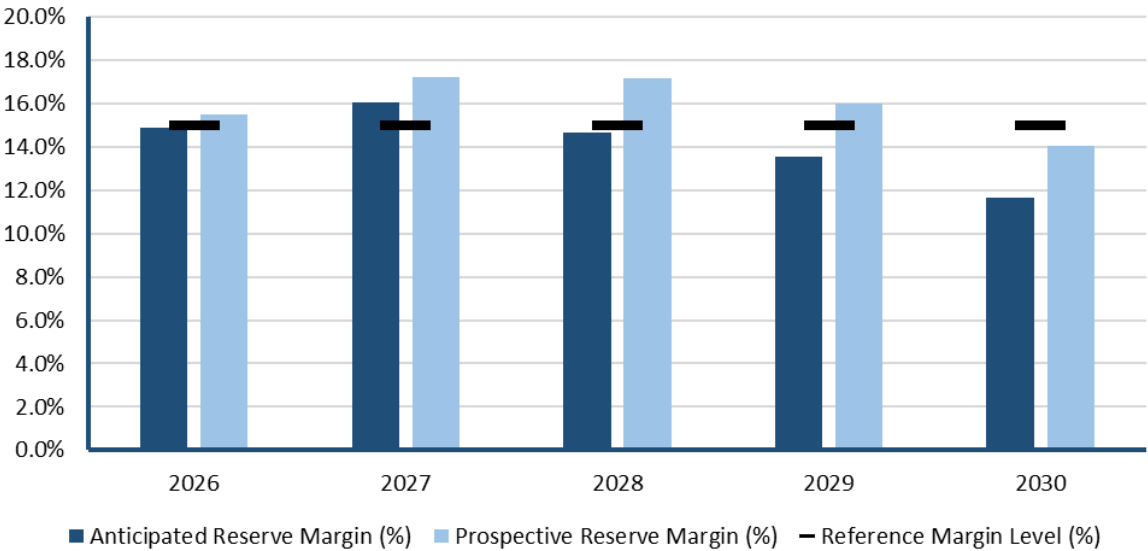


SERC-Central

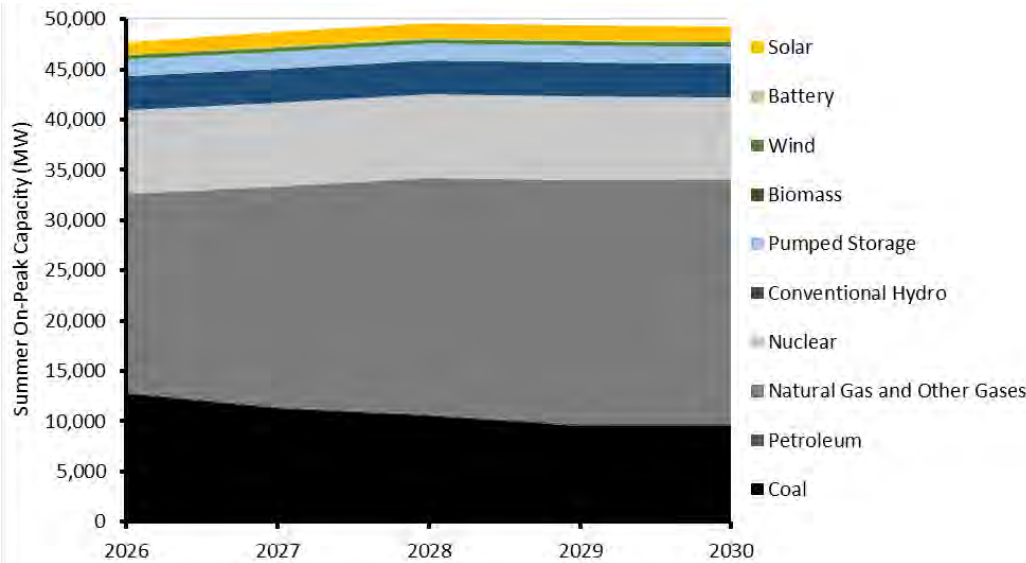
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of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

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	43,066	43,512	44,298	44,616	45,280	45,975	46,034	46,168	46,412	46,619
Demand Response	2,818	3,047	3,287	3,356	3,364	3,377	3,392	3,367	3,323	3,301
Net Internal Demand	40,248	40,465	41,011	41,260	41,916	42,598	42,642	42,801	43,089	43,317
Additions: Tier 1	518	492	4,567	5,435	5,435	5,435	5,435	5,435	5,435	5,735
Additions: Tier 2	20	245	837	837	837	837	837	837	837	837
Additions: Tier 3	178	234	300	362	743	795	2,107	3,293	5,539	5,591
Net Firm Capacity Transfers	460	391	-288	-287	-287	-221	-221	-220	-220	-157
Existing-Certain and Net Firm Transfers	47,859	47,438	45,895	44,503	43,474	43,382	43,448	42,484	42,485	41,414
Anticipated Reserve Margin (%)	19.1%	20.8%	19.7%	18.5%	16.5%	14.8%	12.4%	12.0%	8.7%	9.0%
Prospective Reserve Margin (%)	19.7%	22.0%	22.3%	21.1%	19.0%	17.3%	14.9%	14.5%	11.2%	11.5%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Central Highlights

- SERC-Central is projected to remain above its RML through 2030. The ProbA shows no loss of load over the 2027 and 2029 study years.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	12,782	11,308	10,595	9,565	9,565
Coal*	12,782	11,308	9,944	8,914	8,914
Petroleum	128	128	128	128	128
Natural Gas	19,706	21,956	23,483	24,341	24,249
Natural Gas*	19,279	21,529	22,585	23,443	23,443
Biomass	37	37	37	37	37
Solar	1,181	1,408	1,445	1,455	1,455
Wind	370	370	370	370	370
Conventional Hydro	3,405	3,405	3,405	3,405	3,405
Pumped Storage	1,247	1,247	1,247	1,247	1,247
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	100	135	135	135	135
Total MW	47,236	48,274	49,124	48,963	48,871
Total MW*	47,256	48,267	47,996	47,835	47,835
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Central Assessment

Planning Reserve Margins

PRMs are crucial for ensuring the reliability and adequacy of electric transmission systems in the Central assessment area, with various entities employing different methodologies and targets. The concept of LOLE, often aiming for a standard of one day in 10 years (0.1 LOLE annually), is a critical metric used to establish these targets.

Several entities establish reserve margin levels based on resource adequacy study results. For instance, one entity sets target reserve margins at 29% in winter and 23% in summer, determined using a 1-in-10 LOLE study, a change from its previous economic reserve margin approach, which resulted in lower targets. Another entity performs a reserve margin study using the Astrapé Strategic Energy and Risk Valuation Model (SERVM) to establish summer (18%) and winter (25%) planning targets, balancing seasonal risk and cost, which also aligns with a 1-in-10-year expected probability of a loss-of-load event. Another entity uses the NERC/SERC-accepted 15% reserve margin for predominantly thermal systems, which is generally consistent with a one-day-in-10-year loss of load. Methodologies for determining these margins often involve probabilistic modeling using extensive weather data (e.g., 40 years of weather data with Astrapé SERVM) and simulations of hourly forced outages, load, market availability, and renewable resources. Key drivers of risk often include extreme weather, low renewable generation, forced outages, and limited import capability.

Since the 2024 LTRA, some significant changes have occurred or are underway. One entity recently updated its minimum reserve margin constraints from economic reserve margin targets to a resource adequacy standard of one day in 10 years LOLE. This entity also conducted a LOLE study that incorporated improvements such as enhanced peak demand modeling and additional sensitivities, including temperature-dependent outage probabilities. Load forecasting is also updated annually to meet NERC MOD-32 requirements, aiming to maintain reserve margins at minimal cost while balancing risk, reliability, environmental responsibility, and flexibility.

Currently, most entities’ ARMs are not expected to fall below their RMLs. However, challenges stemming from load growth and increased load sensitivity to weather, particularly in winter, have led to a reduction in reserve margin levels over the next 10 years for some. To address potential shortfalls and future needs, resource additions are being planned, including solar facilities, natural gas combined-cycle units, and battery storage. Utilities also account for uncertainty and variability in assumptions through quantitative scenario modeling and probabilistic weighting of key assumptions. The results of energy risk assessments are used to establish or confirm PRM targets based on simulations and scenario analyses, which account for variability in load, weather, and unit outages to ensure system reliability.

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

Energy risk assessments are an evolving aspect of grid reliability planning, moving beyond traditional peak-demand analyses to encompass all potential hours of the year, including non-peak periods in the Central subregion. These comprehensive assessments are vital due to the increasing variability and uncertainty in system demand and resource mix. Utilities employ a range of methods for these assessments, often including detailed LOLE studies that simulate hourly conditions over a 10-year horizon, incorporating extensive historical weather data and system flexibility. Some entities adopt a holistic, year-round planning approach that integrates scenario-based reserve margin analysis and robust fuel inventory management to handle supply and demand uncertainties. Probabilistic modeling is commonly used, leveraging extensive weather data (e.g., 40 years of weather data), and simulating hourly forced outages, load, market availability, and renewable resources to identify risks across a wide range of conditions.

Key drivers of risk examined in these assessments include extreme weather (both highly unexpected demand impacts and unseasonable conditions), low renewable generation, forced outages, and limited import capability. Other factors considered are low water conditions, fuel availability (such as natural gas pipelines and their interdependencies), resource outages, transmission constraints, common mode failures, correlated and dependent outages (derations), ramping limitations, and flexibility requirements. The results of these energy risk assessments are directly used to establish or confirm PRM targets, which are designed to account for variability in load, weather, and unit outages to ensure overall system reliability. These assessments also emphasize the importance of a balanced and diversified generation portfolio to reduce dependency on single sources and to hedge against supply disruptions. Furthermore, they support detailed operational planning, such as maintaining higher reserve margins during shoulder months to mitigate risks from maintenance outages and unpredictable weather, and implementing fuel security measures like firm transportation contracts and fuel inventory targets. Ultimately, the outcomes of energy assessments inform and guide a broad spectrum of strategic, operational, and planning decisions, ensuring that utilities can build robust, adaptive plans to provide consistent and reliable service despite external uncertainties and the evolving conditions of the electricity system.

ProbA Results

In the SERC model, based on data and assumptions, SERC-Central does not show any loss of load risk for 2027 nor 2029 for any of the 5375 cases. The annual metrics are shown below.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0.10	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
*Provides the 2024 ProbA Results for Comparison			

However, the study shows overall reliance on imports from neighboring areas with the potential of insufficient local generation to meet the demand. The month of April in particular shows the risk of low hydro generation, which can coincide with planned maintenance outages. The summer load forecast is expected to grow by 1,005 MW and winter load forecast is expected to grow by 781 MW from 2027 to 2029. At the same time, there is an expected retirement of approximately coal generation in 2028, leading to tighter margins. Close to 2,600 MW of gas generation is expected to be added in the same period. Based on the ProbA, overall margins get tighter in 2029.

Demand growth, planned generator retirements, fuel diversity and reliance on imports contribute to growing energy risks. SERC and the SERC Central entities will need to continue to monitor the resource adequacy studies.

Demand

Utilities in the Central assessment area employ comprehensive and evolving methodologies to project future energy and demand needs, crucial for accurate system planning. Load forecasts are regularly updated, typically every one to two years, drawing heavily on historical data including hourly load profiles, economic indicators, demographic trends, and weather patterns. Many entities utilize econometric or regression-based models to capture the relationship between energy usage and variables like temperature, population, and housing. To account for uncertainty and variability, some utilities develop multiple forecast scenarios, employing historical weather extremes or probabilistic modeling to capture a range of potential outcomes. Forecasts also integrate emerging factors such as DERs, EVs, and end-use efficiency trends. Advanced modeling techniques include shaping system forecasts with hourly load profiles by customer class and DER type, with adjustments for anticipated industrial or commercial growth. Load forecast uncertainty (LFU) is managed through both quantitative scenario modeling and probabilistic weighting of key assumptions. Forecasts beyond a 10-year horizon, while highly uncertain, provide insights into potential long-term drivers such as the addition of data centers and large commercial/industrial loads, which can substantially increase demand and are often modeled as sensitivities in reliability studies. Electrification trends, particularly in home heating, contribute to increased winter peak sensitivity, and transportation electrification is expected to become a more significant driver beyond the 10-year horizon. While climate change and extreme weather impacts often are not pronounced in probabilistic load models, some models are

refined to reflect more frequent cold weather patterns, and load impacts are often addressed through scenario planning rather than directly embedded in long-range forecasts.

Demand-Side Management

DR and other DSM programs vary significantly across utilities in the Central assessment area, playing a role in managing demand and enhancing system flexibility. Some entities model their DR programs as dispatchable supply-side resources, meaning their contribution is not reflected as load reductions in forecasts, with available capacity often estimated based on historical performance and being highly weather-dependent. Plans are in place for significant expansion of DR capacity over the next five years by some entities. Specific programs include legacy Interruptible Power, the newer PowerFlex offering greater flexibility in response times, and the relaunched dispatchable voltage regulation (DVR) program, which provides enhanced credits for both emergency and capacity events. Conservation voltage reduction (CVR) is employed as a 24/7 energy-efficiency tool, and Peak Rewards is an aggregator-based DR program for large commercial and industrial customers. Capacity from these programs is estimated based on historical reactivity to voltage changes and forecasted load, with some having specific use limitations, such as 400 event hours per year for DVR. While some smaller entities in Central report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, other entities are actively growing this resource class, particularly for DR and peak load management. These aggregator-based programs are included in IRP inputs and modeled through semi-annually updated Power Supply Plan processes. The development and refinement of these programs help utilities ensure consistent and reliable service by balancing supply and demand, especially during critical periods.

Distributed Energy Resources

DERs, primarily solar PV, are generally incorporated into net load forecasts by most entities within the Central assessment area, though the specific methodologies and extent of integration vary. Some entities utilize historical data and national laboratory research to integrate distributed generation and EVs into their peak demand and energy forecasts. For example, one entity projects solar PV to reach approximately 1% of summer peak demand by 2028, with total DER capacity anticipated to be 153 MW by 2032. Another entity, which incorporates both BTM and front-of-meter DERs, forecasts solar PV penetration to grow from 250 MW by 2029 to 350 MW by 2034. They model BTM resources using irradiance-based hourly shapes and treat program-based solar as a fixed energy supply with simulated profiles. Future DER growth is projected using adoption curves based on economic payback periods and market trends, also accounting for local self-generation programs that allow up to 5% of annual energy needs.

However, some entities in the region either do not currently utilize or separately account for DERs due to minimal penetration or a lack of utility-sponsored programs. One entity has implemented a

cap on DER penetration at 10% of peak demand, expecting to reach this limit within five years, and models DERs at 80% of capacity during system peaks. IBRs, which include many DERs, are subject to rigorous modeling and verification processes, including fault ride-through testing, oscillation monitoring, and the enforcement of a minimum short-circuit ratio (SCR) to maintain system reliability.

The contribution of DER aggregators is currently limited but is actively expanding in the assessment area, with select entities integrating them into planning and demand-side management strategies. These aggregator-based programs are included in the entity’s Integrated Resource Plan (IRP) inputs and are modeled through its semi-annually updated Power Supply Plan process. While some smaller entities report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, others with minimal DER participation do not account for them separately in resource planning. The capacity from DER aggregators, where applicable, is generally reflected as part of DR resources and modeled as dispatchable or embedded in the net load forecast, depending on the entity. Overall, the assessment area sees a proactive effort by leading entities to grow this resource class for DR and peak load management as the energy landscape evolves.

Generation

Utilities in the Central assessment area are actively engaged in managing their generation portfolios, which are undergoing significant transformation, primarily driven by the integration of IBRs and a focus on flexible, dispatchable capacity. Planning entities have mechanisms to prevent the retirement of reliability-critical units, such as state laws mandating replacement with dispatchable capacity or ensuring replacement generation is established before retirement. Reliability and reserve margin studies are used to assess the impacts of retirements. One entity maintains its plan to retire a 297 MW coal-fired unit in 2027 due to economic and environmental factors, though the timing is under reassessment. There have been no changes to confirmed or unconfirmed retirements since the 2024 LTRA, with entities projecting no new retirements.

Changing Resource Mix and Operational Considerations: Entities are addressing potential operational issues stemming from this evolving resource mix, particularly due to the increased penetration of solar, BESS, natural gas, and hydro resources. For instance, one entity is retiring a 297 MW coal-fired unit and adding approximately 240 MW of utility-owned solar, a 645 MW natural gas combined-cycle (NGCC) unit, and a 125 MW battery storage facility to enhance system ramping flexibility and absorb more intermittent generation. While annual stability assessments generally show no transmission stability issues, some entities have observed operational challenges related to IBR controls, tuning, and power oscillations. To mitigate these, advanced testing and commissioning processes for new IBRs are being implemented, including a “burn-in” period, and utilities require utility-scale solar resources to operate on automatic generation control (AGC) and allow for

automated, proportional output reductions during surplus conditions. Planning activities regularly assess system inertia with IBRs, finding no critical issues related to low system inertia so far.

Addressing Net Demand Ramping Needs: Planners are proactively ensuring sufficient flexible resources are available for long-term net demand ramping needs. Some entities maintain a diverse mix of flexible, dispatchable resources with no planned thermal asset retirements, ensuring adequate inertia and system stability. One larger entity is preparing for the potential integration of up to 11,000 MW of solar over the next 15 years. Proactive measures include replacing 1,400 MW of aging combustion turbines (CTs) with 1,500 MW of modern Frame-type CTs, refurbishing older peakers, and planning for at least 500 MW of new aeroderivative CTs to support flexibility. Exploration of **long-duration energy storage technologies**, such as pumped hydro, gravity-based systems, and flow batteries, is also underway to provide future flexibility. A contractual ability to curtail solar output during times of low demand and high solar output, particularly in spring, serves as a backup measure.

Capacity Contribution Values for Various Resources: Capacity contribution values for different generation types vary based on resource characteristics and available data:

- **Thermal resources** typically use historical performance data, with planned additions relying on vendor guarantees. Forced outage rates for thermal units are generally not reflected in the reported values.
- **VERs** like wind and solar utilize seasonal or monthly net dependable capacity (NDC) values based on historical performance or modeled solar irradiance at peak times. For example, one entity uses 84% of nameplate capacity for solar in summer and 0% in winter, while another uses a 50% confidence level for monthly wind and solar contributions, accounting for inverter risk.
- **Energy storage** contributions vary by duration and reliability benefit; one entity assigns 93% for 8-hour storage and 85% for 4-hour storage, considering 4-hour duration sufficient for reliability.
- **Hydroelectric resources** are evaluated using historical seasonal performance. Most methodologies have remained consistent since the previous LTRA, with updates primarily to assumptions for loads, outages, and transmission imports. Probabilistic modeling, such as ELCC, is used to ensure resource adequacy.

IBR Performance and Reliability: Entities are actively addressing reliability risks from IBRs through various study requirements and operational protocols. Some require EMT models as part of the interconnection study process. Rigorous modeling and validation practices are implemented, including mandating PSSE and PSCAD models for interconnection, enforcing quality control, and evaluating harmonic distortion. A key focus is on inverter control systems that prevent momentary cessation and ensure inverters remain on-line during voltage and frequency excursions. While no

protection schemes or ancillary service needs have explicitly emerged, increased regulation demand has been observed with growing IBR penetration. AGC capability is being mandated for all new utility-scale solar facilities, and legacy plants are being retrofitted to allow system-wide output reductions for flexibility during surplus generation events. The primary challenges with IBRs relate to system stability and control rather than resource adequacy.

Generator Retirements

Natural Gas Fuel Supply Risk: Natural gas fuel supply risk is mitigated through various strategies, including **on-site fuel oil backup** at key generation sites and contingency-based studies simulating pipeline disruptions. One entity estimates that approximately **87% of its gas-fired winter peak capacity will have firm gas transportation or fuel oil backup** within the next five years. Following a 2022 winter event, reliability improvements were implemented by an affected pipeline operator. Strategies also include 100% storage-backed firm transportation for combined cycle units, diverse procurement and scheduling, and embedding fuels personnel in system operations for real-time communication with pipeline operators during contingency events. Long-term planning considers natural gas infrastructure limitations when evaluating new generation resource locations, ensuring fuel supply adequacy and construction timelines.

Energy Storage

Energy storage, primarily BESS, is being added to the system and is expected to contribute to reliability and flexibility. Expected uses include economic operation, reliability enhancements, peak shaving, and frequency response. The capacity contribution of energy storage is factored in based on its supply duration, with entities considering different minimum durations (e.g., 4-hour or 8-hour discharge capability). One entity is adding a 125 MW battery storage facility. These resources are incorporated into long-term planning through IRPs and power supply processes.

Capacity Transfers

The Central assessment area is proactively managing capacity transfers and ensuring transmission adequacy through a variety of studies, strategic investments, and coordinated efforts to maintain system reliability amidst an evolving resource mix and load growth.

The assessment area's ability to transfer capacity is continuously evaluated and is evolving:

- **Evaluation Methods:** Transfer capabilities are assessed through biennial resource adequacy studies that account for firm contracts and probabilistic delivery expectations, showing a positive contribution from increased firm contractual capacity to overall reliability. Seasonal assessments are also conducted to identify surplus transfer capacity across different times of the year, allowing for more accurate planning of bidirectional flows and optimizing the scheduling and delivery of transfers.

- **Observed Impacts and Trends:** One entity has seen an increased reliance on external generation resources, with over 6% of its firm capacity sourced from outside its immediate footprint, driven by fossil unit retirements, load growth, and shifts in its generation portfolio. While no significant changes in power flow patterns have been identified overall, the ongoing transition in the resource mix, along with planned retirements and new additions, is anticipated to influence future transfer scheduling, surplus availability, and bi-directional flow characteristics.
- **Coordinated Efforts:** Entities are implementing various coordination efforts to ensure reliable capacity transfers:
- **Seasonal Capacity Transfer Studies** analyze how different system conditions (e.g., summer and winter peaks, shoulder months) impact import/export capabilities.
 - A transfer monitoring process tracks firm capacity from external generators, ensuring their reliable availability during peak conditions.
 - Coordination with neighboring balancing authorities is undertaken to secure contractual commitments and physical transfer capability.
 - Some entities embed transfer analysis into their long-term planning documents (e.g., IRPs) to evaluate how future firm transfers impact transmission constraints and local reliability.

Transmission

Entities in Central are maintaining transmission adequacy, with significant projects and planning processes in place to address limitations and ensure reliability.

- **Major Transmission Projects:** The assessment area is undertaking numerous projects to support reliability and accommodate changing load and generation patterns. These include the following:
 - **New Line Construction:** Approximately 158 miles of new 345 kV lines and 18 miles of 161 kV lines, along with new 56 MVA 161/69 kV stations
 - **Substation Construction and Expansion:** Three new 345/161 kV stations and one new 161 kV switching station
 - **Transformer Additions/Upgrades:** Various upgrades to 345/161 kV and 161/69 kV transformers to increase capacity
 - **Line Rebuilds and Voltage Conversions:** Over 227 miles of 161 kV lines are being rebuilt, and nearly 20 miles of 69 kV lines are being converted to 161 kV

- **Voltage and Stability Projects:** Installation of a 60 MVAR capacitor bank (by 2025) and planned Statcoms to address voltage reliability
- **Regional Reinforcements:** Projects like a new 161 kV Line and Apalachia Area Improvements are critical to mitigate thermal overload, voltage collapse, and support native load reliability
- **Identified Transmission Limitations:** Planning studies have identified constraints often associated with transformer overloads, line loading issues, or high-voltage conditions.
- **Mitigation Planning and Actions:** To address identified limitations, utilities employ the following:
 - **Operating Guides and Real-Time Controls:** Providing generation dispatch limits or specific switching actions for constrained locations
 - **Infrastructure Expansion:** Planning multiple long-term system reinforcements
 - **Congestion Management Processes:** Using system operator tools and protocols to re-dispatch generation or adjust flows
 - **Annual Transmission Assessments:** Identifying and addressing long-term transmission constraints, including new service requests and interconnections
- **Changes to Transmission Planning Processes:** Since the 2024 LTRA, several enhancements are being implemented or considered:
 - Expanding the biennial Long-Range Plan to incorporate power transfers and extreme weather events
 - Updating generator interconnection and affected system procedures to comply with FERC Order No. 2023, with one entity transitioning to a cluster study approach (transitional cluster in 2025, full cluster in January 2026) to streamline interconnection requests and reduce backlogs
 - Evaluating multi-value projects through resource and capacity assessments to proactively address long-term transmission needs

Reliability Issues

The Central assessment area is actively managing and addressing a range of reliability issues stemming from evolving system conditions, including changes in resource mix, load growth, and extreme weather.

- **Reduced Reserve Margins and Challenges from Load Growth:** Entities in the SERC-Central region are confronting challenges due to load growth and an increased sensitivity of load to weather, especially in winter, which has resulted in a reduction in reserve margin levels over the next 10 years. While some entities anticipate their ARMs will not fall below their RMLs, one entity projects that without replacement resources, its reserve margin would fall below its target range due to a unit retirement in 2027, necessitating further resource additions for increasing economic development load beyond 2027. Underlying reliability issues include increasing winter peak demand sensitivity to weather and the potential for new large commercial loads. To address this, resource additions are being planned, and some entities are shifting their minimum reserve margin constraints to a resource adequacy standard of one day in 10 years LOLE, moving away from prior economic reserve margin targets that resulted in lower targets. Large industrial or commercial load additions, such as data centers and manufacturing centers, are actively monitored as they can introduce reliability risks due to short lead times and uncertain scalability, potentially challenging load forecasting and transmission development.
- **Operational Issues and System Stability with the Changing Resource Mix, Particularly IBRs:** The assessment area is actively addressing potential operational issues stemming from the increasing integration of IBRs like solar and BESS. Some entities have experienced operational challenges related to IBR controls, tuning, and power oscillations, including instances where solar generation contributed to over-generation events. While annual stability assessments have not yet identified transmission stability issues or critical issues related to low system inertia, increased regulation demand has been observed with growing IBR penetration. To manage these risks, entities are implementing proactive measures such as advanced testing and commissioning processes for new IBRs, requiring them to demonstrate stable performance. New utility-scale solar facilities are being mandated to operate on AGC, and legacy plants are being retrofitted for system-wide output reductions to provide flexibility during surplus generation events. The primary challenges related to inverter risks in the assessment area are system stability and control, rather than resource adequacy.
- **Natural Gas Fuel Supply Risk:** The reliability of the BPS faces risks from natural gas generator fuel supply issues, including production or transportation curtailments and limitations during both normal and extreme weather conditions. To mitigate these risks, various strategies have been developed.

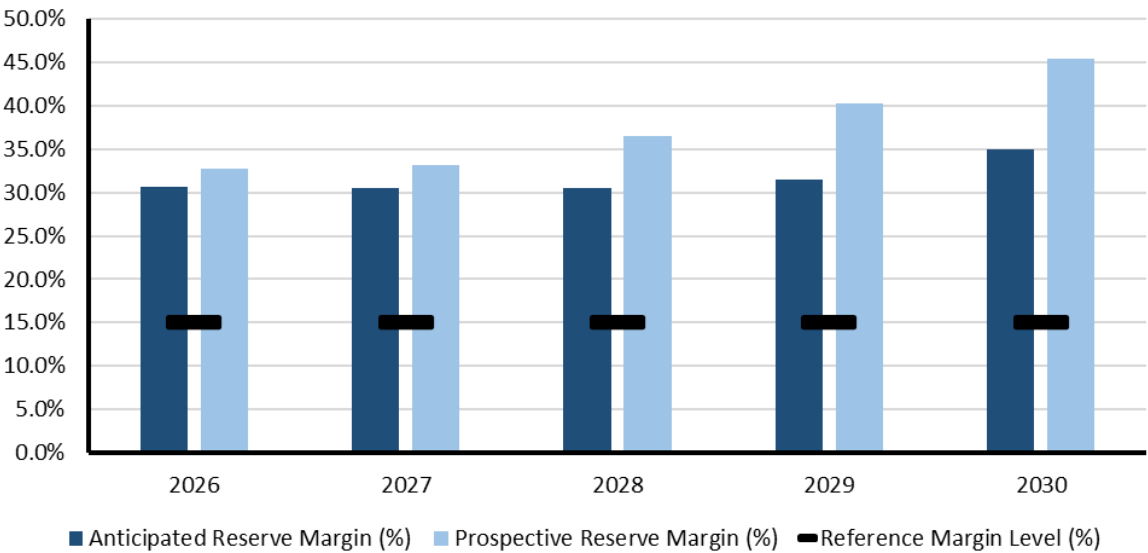


SERC-East

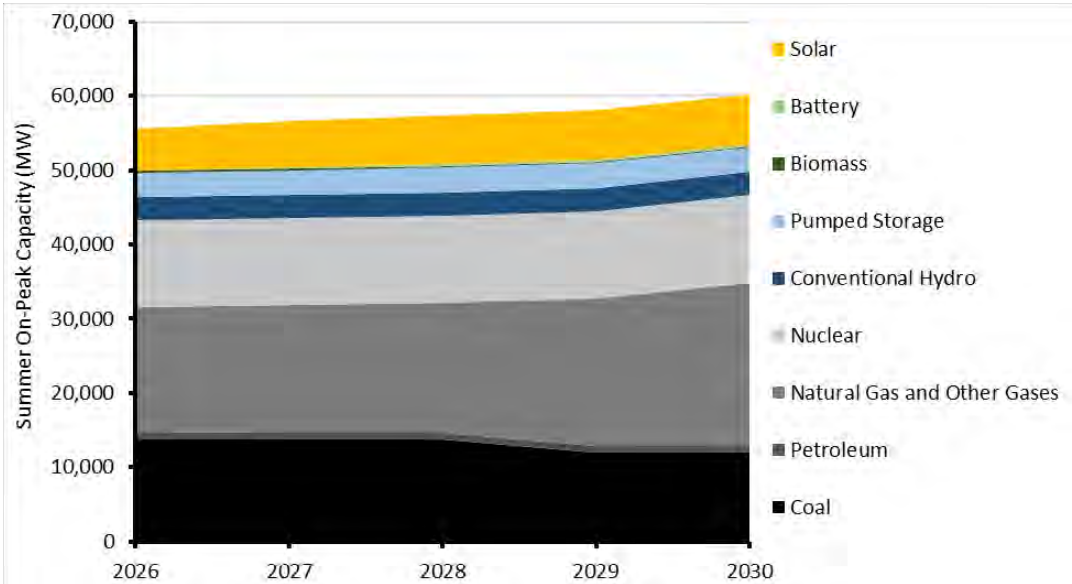
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible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

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	44,414	45,289	45,893	46,128	46,646	47,256	47,776	48,445	48,870	49,313
Demand Response	1,608	1,620	1,621	1,652	1,679	1,702	1,726	1,751	1,773	1,795
Net Internal Demand	42,806	43,669	44,272	44,476	44,967	45,554	46,050	46,694	47,097	47,518
Additions: Tier 1	959	2,109	2,817	5,282	7,348	8,656	9,921	11,186	11,186	11,186
Additions: Tier 2	215	484	2,009	3,231	4,045	4,551	5,114	6,232	9,022	9,022
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	150	150	150	236	236	236	236	236	236	236
Existing-Certain and Net Firm Transfers	54,964	54,880	54,953	53,222	53,316	52,237	50,919	50,919	49,557	49,557
Anticipated Reserve Margin (%)	30.6%	30.5%	30.5%	31.5%	34.9%	33.7%	32.1%	33.0%	29.0%	27.8%
Prospective Reserve Margin (%)	32.7%	33.1%	36.5%	40.3%	45.4%	45.1%	44.7%	47.8%	49.5%	48.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-East Highlights

- The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years.
- To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	13,715	13,715	13,715	11,898	11,898
Petroleum	1,044	992	992	992	992
Petroleum*	1,044	868	868	868	868
Natural Gas	16,737	17,081	17,396	19,816	21,851
Biomass	176	176	176	176	176
Solar	5,649	6,223	6,626	6,671	6,702
Conventional Hydro	3,094	3,094	3,094	3,094	3,094
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,808	11,808	11,902
Battery	8	208	258	258	258
Total MW	55,540	56,606	57,388	58,035	60,196
Total MW*	55,540	56,482	57,264	57,911	60,072
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-East Assessment

Planning Reserve Margins

PRMs in the assessment area are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. However, there are variations among entities. For instance, one generation-only BA with an all-hydro portfolio finds reserve margin requirements inapplicable, while another entity reports sufficient margins. A third entity anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and its targeted 18% winter reserve margin. To address this, it has issued requests for proposals for new capacity resources, including battery energy storage, and is evaluating longer-term options.

Other entities expect their reserve margins to remain above the 15% reference level for both near-term (0–5 years) and longer-term (6–10 years) outlooks, despite significant projected winter load growth of approximately 2% annually, which is expected to increase winter peak demand by about 6,500 MW by 2035. Their IRPs identify substantial new resources through 2035, including thousands of megawatts of solar, battery storage, wind, combustion turbines, combined-cycle units, and small modular nuclear reactors. They also plan to implement uprates to existing units. These entities aim to achieve a 22% winter PRM by 2031. Approximately 5,800 MW of coal generation is slated for retirement over the next decade, but these retirements are contingent on securing sufficient replacement capacity to maintain reliability and meet the 22% winter reserve margin target. Without firm replacement resources, coal retirements would be deferred to preserve system reliability.

Since the 2024 LTRA, most entities have not significantly changed their resource adequacy planning or procurement processes. One entity, operating hydro-only resources, has not made any changes, nor has another entity that is replacing coal-fired generation with natural gas combined-cycle units, though this shift indirectly enhances reliability. However, a third entity, based on its 2022 LOLE study, increased its winter reference PRM from 12% to 18% by 2026, while maintaining the summer reserve margin at 15%. This adjustment reflects heightened concern over winter reliability risks due to electrification trends and potential load increases. Other companies continue to refine strategies for load growth, resource additions, unit uprates, and retirements, maintaining an “all-of-the-above” strategy.

The RML is typically determined by each entity using probabilistic reliability metrics, commonly targeting a LOLE of no more than 1 day in 10 years, or to comply with state requirements. Entities establish separate summer and winter RMLs, considering factors such as load forecast uncertainty, generator availability, and extreme weather impacts. Planning relies on detailed statistical modeling and ELCC studies to assess resource contributions, particularly for variable energy resources like solar,

batteries, and wind. The capacity contribution values for variable energy resources and energy storage are determined by ELCC analyses, which discount nameplate capacity to firm, dependable capacity to meet LOLE standards, while non-variable resources like thermal units are counted at their nameplate capacity. Uncertainty and variability in assumptions are accounted for through “High” and “Low” load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, which in turn drive planning reserve and resource-adequacy sensitivity cases. Although no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources. A reliability verification step within the IRP process ensures that any developed portfolio meets reliability criteria, regardless of its stated installed capacity (ICAP) margin.

Energy Risk, Probabilistic-Based Assessments

Entities within the assessment area exhibit varying approaches to assessing energy risk, with some currently in the early stages of implementation or lacking formal processes. For instance, one generation-only BA with an all-hydro portfolio has not identified any energy risks to date. Another entity has yet to establish a formal energy risk assessment process but is preparing for the forthcoming implementation of NERC’s BAL-007-1 standard, which will mandate the development of such procedures and assessments. A third entity also acknowledges the importance of developing these capabilities but currently has no established process or results to report.

Despite the current limitations in formal assessments, the sources indicate that key drivers of energy risk expected to be considered in future evaluations include the following:

- Fuel availability constraints, particularly concerning natural gas supply and delivery
- Impacts from unseasonable extreme weather
- Limitations of variable energy resources
- Transmission or interchange constraints
- Correlated outages
- Other factors such as low water conditions, resource outages, and ramping limitations

Entities within the assessment area extensively employ probabilistic reliability metrics and studies as fundamental tools in their transmission and resource planning processes. These assessments are primarily centered on determining resource adequacy and PRMs, with a common objective of achieving a LOLE of no more than 1 day in 10 years. This probabilistic standard is a cornerstone for establishing the reliability needed to meet anticipated demand.

Key probabilistic assessments and their applications include the following:

- **LOLE Studies:** These studies are crucial for setting PRMs. For example, one entity increased its winter reference PRM from 12% to 18% by 2026 following a 2022 LOLE study, reflecting heightened concern over winter reliability risks due to electrification trends. The results from LOLE models are also used in a reliability verification step within IRPs to ensure that proposed resource portfolios can meet reliability thresholds year-round, including accounting for net demand ramping and energy adequacy needs.
- **ELCC Studies:** These are a specific type of probabilistic assessment used to determine the capacity contributions of VERs such as solar, wind, and battery storage. Unlike non-variable resources like thermal units, which are typically counted at their nameplate capacity, VERs and energy storage undergo ELCC analyses to discount their nameplate capacity to firm, dependable capacity that effectively contributes to meeting LOLE reliability standards. ELCC studies account for factors such as the intermittent, diurnal nature of solar output, especially noting that solar output is minimal during typical winter peak loads (early morning and late evening).
- **Statistical Modeling:** Entities use detailed statistical modeling to establish separate summer and winter RMLs, considering factors like load forecast uncertainty, generator availability, and extreme weather impacts. While no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources.
- **Stochastic Analysis in Load Forecasting:** To account for the inherent uncertainties in demand, especially with the addition of large industrial customers like data centers, entities employ stochastic analyses. For instance, one entity uses a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects.
- **Load Forecast Uncertainty (LFU) Scenarios:** Planning processes integrate “High” and “Low” load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake. These scenarios directly drive planning reserve and resource-adequacy sensitivity cases, allowing planners to assess system resilience under different conditions.

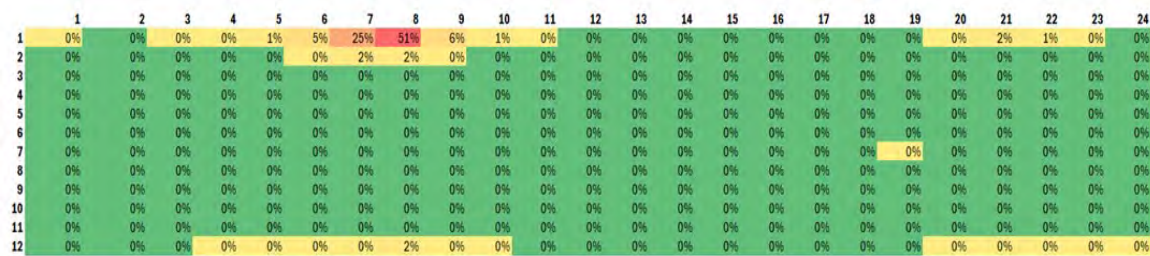
Regarding non-peak hour risk and energy assessments, entities are in varied stages of implementing formal processes. While some currently lack established procedures, they acknowledge the forthcoming implementation of NERC’s BAL-007-1 standard, which will mandate the development of such assessments. As these formal energy risk assessments are initiated, future reports are expected to include risk quantification tied to specific drivers (e.g., fuel supply constraints, weather-driven demand volatility, system flexibility limitations) using probabilistic metrics across operational time

frames, beyond just peak demand hours. These formal energy risk assessments, once fully implemented, are intended to be essential tools for informing strategic planning and operational decisions to ensure resource capacity is available across a broad range of conditions.

ProbA Results

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	143	231	538
NEUE (ppm)	0.60	0.98	2.27
LOLH (hours per Year)	0.09	0.16	0.33
*Provides the 2024 ProbA Results for Comparison			

The ProbA results for the year 2027 indicate some risk for SERC-East in the winter months of January and February. This is in line with the risk findings of previous ProbA studies. The annual EUE is 231.75 MWh but for a very short, expected duration of 0.15 hours. As shown in the 2027 EUE Heat Map below, the risk occurs during winter morning hours around 7:00-8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. The risk is seen mainly in January but on a smaller scale in the other winter months of February and December. The major contributing weather-years to the EUE in the model are 1982 and 1985, which experienced one of the worst winters throughout the SERC Region, limiting the amount of imports from neighboring subregions.



2027 EUE Heat Map

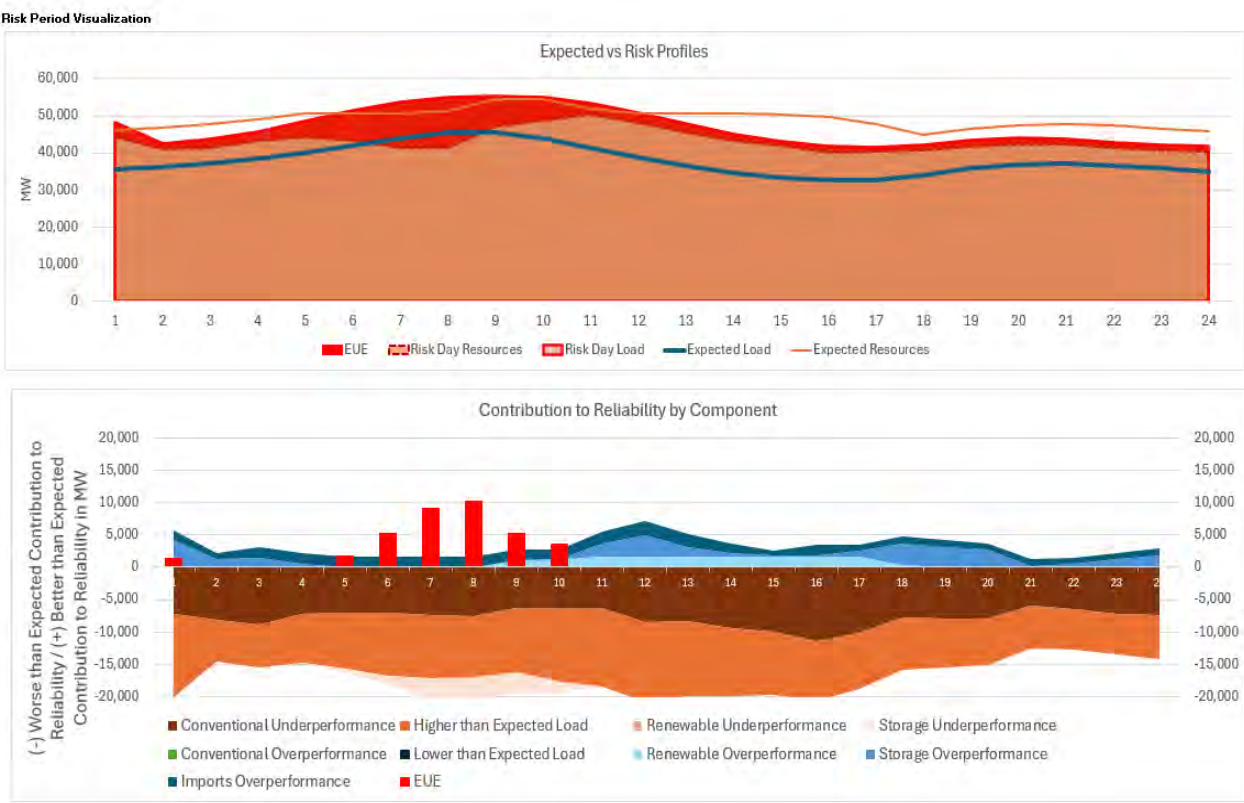
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	1%	7%	23%	41%	9%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	1%	3%	5%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	1%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2029 EUE Heat Map

For the year 2029, SERC-East risk continues to grow with 538.48 MWh of EUE and 0.33 hours of LOLH. As is shown in the 2029 EUE Heat Map above, the trends of risk are similar to the findings of 2027, with risk is expected to occur primarily in January, but other winter months of February and December as well. The expected duration of risk is still very short, occurs around 7:00-8:00 a.m. Load is expected to grow in SERC-East. In 2028, more than 1800 MW of coal is expected to retire. While there are some replacements with battery, solar generation, and DR, they are limited in the winter morning risk hours as seen in the study and contribute to the increase in EUE in 2029.

Between 2027 and 2029, there is an expected addition of 683 MW summer load and 985 MW winter load. In the last stages of the ProBA, SERC worked with its entities to identify an error in winter load forecast reporting. We are unable to rerun the model in time for the submission however, we are working with the entities to make the correction to the LTRA. For SERC-East, the overall 2029 winter load forecast should be 1932 MW than is currently reported. The expected risk would be higher along the same trends as is seen in the present study for the year 2029

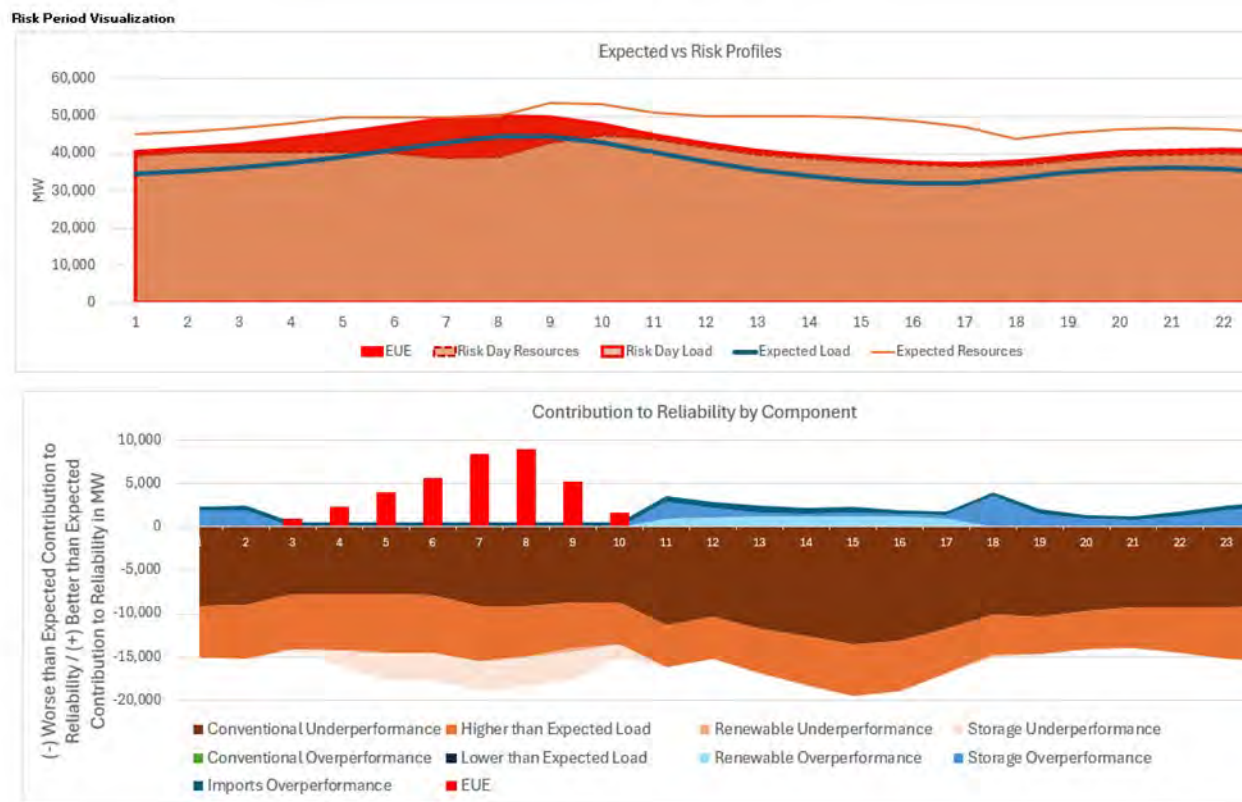
In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2027.



Expected vs. Risk Profiles and Contribution to Reliability by Component

The event day with the worst case EUE hour was chosen for reference (load forecast error +4%, weather year 1985, winter). The chart shows risk during winter morning hours from 4:00-10:00 a.m. and 12:00-1:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. Some imports from neighboring areas are available.

The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029. The event day with the worst case EUE hour was chosen for reference (load forecast error +2%, weather year 1985, winter).



Similar to the 2027 event, there is risk during winter morning hours from 3:00-11:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. While there are some imports from neighboring areas available, it is much lower in this event.

Demand growth and planned generator retirements contribute to growing energy risks. SERC and the SERC East entities will need to continue to monitor the resource adequacy studies.

Demand

The assessment area develops its load forecasts using a combination of short-run and long-run econometric techniques, which are then aggregated into a coincident system peak outlook. One entity uses statistically adjusted end-use (SAE) models for customer classes, supplemented by adjustments for energy-efficiency programs, rooftop solar, and EV forecasts from external consultants. Another entity applies SAE regression for residential and commercial classes, a consultation-based approach

for large industrial customers, and a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects. Municipal and wholesale sub-area forecasts are integrated to form the coincident peak, with contracts having defined end dates removed to prevent overstatement of future demand. Load forecast uncertainty (LFU) is addressed through “High” and “Low” scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, driving planning reserve and resource-adequacy sensitivity cases. Since the 2024 LTRA, key refinements include the explicit addition of an EV demand component starting in 2025, more frequent updates for large industrial prospects, and expanded stochastic modeling to capture rising volatility from electrification and BTM generation.

Changes in the 10-year forecasted demand and energy growth rates since the 2024 LTRA are primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These loads are accounted for via a post-modeling stochastic adjustment from active projects and are a significant driver, contributing approximately 1,100 MW by 2034. Electrification trends, particularly EV adoption, are also included, projected to increase residential and commercial summer peak demand by 33 MW and winter demand by 3 MW by 2034. Rooftop solar is forecast to offset summer demand by 3 MW, with no winter peak impact. Other potential drivers like geographic/demographic shifts, economic outlook, EE (beyond standard modeling), flexible loads, extreme weather, and climate change are currently not considered significant contributors to forecast changes. Beyond the 10-year window, electrification and industrial expansion are expected to continue influencing demand, though uncertainty increases.

Demand-Side Management

DR programs are actively monitored and managed through contractual agreements, control technologies, and performance metrics. DR capacity primarily supports the grid during peak periods, with one entity’s capacity mainly from interruptible loads and customer standby generation based on contracted firm demand. Programs focus on winter peak capacity support with some summer use but do not currently address ancillary services. Recent initiatives include a residential DR program (smart thermostat rewards, peak time rebates, time-of-use education) and a residential DR program with load control switches on HVAC units and water heaters, contributing about 2.3 MW based on industry benchmarks. However, efforts to develop more precise baselines for measuring performance have yielded inconsistent results, especially in winter, leading to continued reliance on industry averages. Plans include piloting a “Bring Your Own Thermostat” initiative and transitioning to smart thermostat and other grid-edge technologies due to limitations of current switch-based programs.

Since the 2024 LTRA, regulatory approvals have expanded incentives for most residential controllable programs (heat strip control, thermostats, water heaters, batteries, except the newer battery program) and increased program coverage. This includes a statewide water heater switch program

launching in 2025, adding November as a winter control month, and enabling year-round water heater control. Emerging technologies like EV batteries, smart panels, home automation, and smart inverters are being monitored for future inclusion. A multi-year initiative has been approved to quantify broader value streams from DR, potentially including energy, regulation, and ancillary services. For non-residential customers, a “Bring Your Own kW” winter load curtailment program is expanding, and two new 2025 programs offer an economic curtailment option and a shorter emergency curtailment program. A planned retirement of one large customer DR program aims to streamline offerings into a unified portfolio called PowerShare.

No major changes have been reported for EE and conservation since the 2024 LTRA, but refinements are being considered. EE impacts are integrated into load forecast models as post-modeling adjustments, reflecting incremental improvements and new program designs. EE is embedded within customer class forecasts and refined through stakeholder input and ongoing evaluation. Looking ahead, increased focus is expected on load-modifying technologies, smart home integration, and more dynamic EE measurement approaches, potentially through real-time metering data or integration with distributed energy resource management systems (DERMS).

Distributed Energy Resources

DERs, particularly BTM solar PV, are anticipated to experience gradual growth within the assessment area over the next 5 and 10 years, although their current penetration levels remain low. Forecasts project residential solar installations to grow by approximately 8% in 2025, tapering slightly to 7% in 2026 and 2027, and then stabilizing around 6% annually thereafter. These projections are informed by local adoption trends, national market dynamics, and regression models that consider economic payback factors such as installation costs, incentives, and bill savings. Historical metering data also shows a recent decline in new BTM installations due to the expiration of DER incentive programs, which influences future projections.

In terms of integration into planning, BTM solar generation is primarily treated as a load modifier, effectively reducing net load through hourly profiles consistent with prior methodologies. Transmission planning similarly incorporates DER generation as a load reduction rather than a supply resource. For generation planning, the capacity value of solar is assessed through ELCC studies due to its intermittent and diurnal nature. Unlike fully dispatchable thermal resources, which are counted at their full nameplate capacity, solar output varies and typically yields minimal output during early morning and late evening winter peak loads. Summer peak loads align better with solar generation, but its capacity contribution still requires careful assessment through ELCC to discount nameplate capacity to firm, dependable capacity to meet LOLE reliability standards.

The system-level impact of current BTM solar on peak demand and load shapes has been minimal, with no significant operational issues identified from existing penetration levels. BTM solar output is projected to represent only 1% to 1.5% of system load over the planning horizons. While no DER-related reliability risks are anticipated for summer 2025, entities are monitoring for potential localized impacts on midday load in areas with higher solar density. Aside from solar PV, no other types of BTM DERs are currently known to materially affect demand-side profiles.

Regarding DER aggregators, there are currently no active or projected aggregators contributing to electricity demand management within the assessment area, and no such capacity is included in forecasts for the next 5 or 10 years. No formal programs are in place to involve DER aggregators in wholesale electricity markets or Integrated Resource Plans, and no virtual power plants operate within the system. While broader grid reliability studies, particularly concerning IBRs, have been conducted through collaborations like the Eastern Interconnection Planning Collaborative, these efforts have not yet extended to DER aggregation. However, if DER aggregator participation increases in the future, planning practices will be adjusted accordingly.

Since the 2024 LTRA, there have been no major modifications to DER monitoring or modeling methods. However, future updates aim to distinguish between solar-only and solar-plus-storage DERs. Load forecast uncertainty (LFU) scenarios do account for rooftop solar penetration and BTM generation, reflecting the rising volatility introduced by electrification.

Generation

Generation planning and management within the assessment area involve a comprehensive set of studies and strategies to ensure reliability amidst an evolving resource mix and increasing load growth.

Overall Planning and Resource Mix Evolution

Entities in the assessment area conduct extensive reliability studies as part of their resource planning, including resource adequacy and LOLE studies, typically targeting a reliability standard of no more than 1 day in 10 years. These studies inform integrated resource planning (IRP) processes, which evaluate new generation scenarios and resource transitions.

The resource mix is undergoing significant changes, driven by the following:

- **Retirements:** Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are contingent on securing sufficient replacement capacity to maintain reliability and a target winter reserve margin. For instance, Roxboro units are expected to retire 1,156 MW by 2028 and 1,402 MW by 2033, and Mayo 763 MW by 2030, all dependent on replacement capacity being online. Planning entities proactively manage

these risks through transmission impact studies and will delay retirements if replacement resources are not operational.

- **New Additions:** To meet growing demand and replace retiring capacity, IRPs identify substantial new resources through 2035. These include thousands of megawatts of solar, battery storage, wind, combustion turbines (CT), combined cycle (CC) units, and small modular nuclear reactors (SMR). Some entities are also replacing coal-fired generation with natural gas combined-cycle (NGCC) units to introduce more flexible, dual-fuel generation that supports VER integration.
- **Load Growth:** Significant winter load growth of around 2% annually is projected between 2025/2026 and 2034/2035, increasing winter peak demand by approximately 6,500 MW. This growth is primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These high-load, high-duty-factor customers require resource portfolios capable of sustaining elevated energy demand beyond typical seasonal peaks.

Capacity Valuation and Reliability

For resource adequacy, entities determine PRMs to meet reliability standards.

Capacity Contribution Values: Capacity contributions for different generation types are assigned using a mix of historical performance data and model-based simulations:

- **Variable Energy Resources (VER):** For intermittent resources like solar, onshore wind, offshore wind, and storage, ELCC studies are essential. ELCC studies discount the nameplate capacity of VERs to determine their firm, dependable capacity to meet LOLE reliability standards. Solar output varies and often yields minimal output during early morning and late evening winter peak loads, though summer peak loads align better with solar generation. ELCC values for solar and battery storage are typically updated every three years.
- **Thermal Resources:** Non-solar, wind, and storage resources, such as thermal units, are generally counted at their full nameplate capacity.
- **Hydro Resources:** For hydro-only entities, capacity contributions are based on hydro capacity and remain stable.

Reserve Margins: Reserve margins are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. One entity, however, anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and has increased its winter reference PRM from 12% to 18%. Another entity plans to adopt a 22% winter reserve margin by 2031.

Operational Considerations

Planning activities are actively underway to address potential operational issues from the evolving resource mix:

- **Ramping Needs:** Planning entities estimate ancillary service needs, such as regulation, balancing, and contingency reserves, to ensure operational reliability amid high penetrations of VERs. While some entities with hydro-based or dispatchable, fast-ramping units have no immediate ramping concerns, and others conduct triennial integration studies aligned with their IRPs to assess the system's ability to integrate intermittent generation.
- **Inertia and Stability:** Stability assessments are conducted as part of TPL-001 compliance and interconnection cluster studies. These studies account for new generators and evaluate the growing share of VERs. Results thus far have not revealed significant stability concerns. If a weaker area with lower inertia is identified, further analysis like EMT modeling may be conducted, and adjustments to IBR performance settings or transmission system upgrades are considered.
- **IBRs:** As solar PV integration grows, interconnection studies now mandate the use of EMT models to evaluate IBR performance during disturbances, addressing issues like momentary cessation and fault ride-through. These studies ensure inverter settings comply with NERC standards (e.g., PRC-024) and FERC Order 827. Efforts focus on maintaining network reliability and system stability. While no new ancillary service needs have emerged in the near five-year horizon, entities are considering adopting IEEE 2800 standards.
- **Natural Gas Fuel Supply Risk:** Planning entities have implemented measures to mitigate risks from natural gas fuel supply disruptions, especially during extreme weather. All natural-gas-fired combined cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Future resource planning assumes on-site backup fuel or dual-fuel capability. Long-term studies factor in fuel supply constraints and infrastructure bottlenecks.

Energy Storage

Energy storage (ES) systems, particularly BESS, are anticipated to see significant capacity installations over the coming decade.

Purpose: Much of the planned BESS will be paired with solar facilities to store excess solar generation and enhance system flexibility. The region also operates substantial pumped hydro storage, used to meet load economically and manage generation ramping requirements.

Integration: Energy storage projects are evaluated through generator interconnection studies, modeling both charging and discharging behaviors. Both standalone and hybrid (paired with renewable generation) storage systems are planned for deployment.

Modeling: BESS are modeled assuming a four-hour discharge duration, with capacity contributions varying based on system conditions and resource mix. Hybrid and standalone battery systems are evaluated using ELCC to capture their effective capacity contribution during peak demand periods.

Capacity Transfers

Energy transfer needs and capabilities are undergoing changes, primarily driven by anticipated load growth and the potential retirement of generation resources.

While one generation-only BA does not foresee any changes to its transfer capabilities, other entities acknowledge that the potential retirement of coal plants could constrain transfer capability. To address these potential constraints, new transmission projects are being evaluated and planned. In response to increasing load demands, particularly within specific BAs, multiple active transmission projects are underway to enhance near-term transfer capabilities. Firm transmission service contracts have been secured to support future transfer needs tied to generator retirements, indicating a reliance on these transfers to maintain reliability. Long-term transmission and resource adequacy planning efforts, including IRPs and coordination with neighboring utilities, are ongoing to ensure the region maintains sufficient capacity and transfer reliability. Planning entities model projected resource additions and retirements and incorporate these into transmission models to identify and address any negative impacts through reliability assessments. Long-term firm imports have been requested from neighboring regions to assess whether external capacity transfers might be more cost-effective than developing new local resources, highlighting a consideration for reliance on external capacity for reliability and economic reasons. Potential organizational changes, such as merging BAs, are also being modeled and assessed to ensure system reliability is maintained.

Transmission

Major transmission projects are identified through annual planning assessments to support and maintain system reliability. These projects include new transmission lines (including HVdc), reconductor projects, and power electronic devices like static var compensators (SVC). For instance, a new 230 kV line and synchronous condensers are planned to improve reliability and reduce congestion in coastal areas, and an additional circuit in South Carolina will address low-country congestion. Transmission limitations and constrained areas are identified through annual assessments, but no widespread transmission-constrained areas have been identified in recent planning studies. However, an operating guide exists to manage potential overloads on a specific transmission line. Interconnection study processes are crucial for detecting and resolving potential

constraints before new generation is brought online, which helps prevent congestion during real-time operations. Since the 2024 LTRA, there have not been major changes to transmission planning processes, but entities are actively responding to evolving regulatory requirements, such as FERC Order No. 2023. This includes developing new processes for interconnection heat maps, implementing updated interconnection and affected system processes (including cluster studies), and evaluating grid-enhancing technologies (GET). A business practice is being developed to formalize how GETs will be assessed in both transmission planning and interconnection analyses.

In summary, capacity transfers are important for reliability in this assessment area. System adequacy is maintained through proactive planning for new transmission projects, securing firm transfer contracts, evaluating external imports, and continually refining planning processes to accommodate evolving load and resource dynamics.

Reliability Issues

Entities in East have identified several key reliability issues primarily stemming from projected load growth, an evolving resource mix, and critical infrastructure interdependencies. These challenges necessitate proactive planning and operational adjustments to maintain BPS reliability.

Firstly, large, new load additions, particularly data centers and other industrial facilities, are the primary drivers of significant changes in the 10-year forecasted demand and energy growth rates. These high-load, high-duty-factor customers could strain both generation and transmission resources if not adequately planned for. One entity anticipates potential reserve margin challenges starting in Winter 2027 due to these significant new load additions and is proactively issuing requests for proposals for new capacity resources. All substantial new loads are subjected to interconnection studies to assess their reliability impacts and determine necessary transmission upgrades.

Secondly, the management of generator retirements and the assurance of sufficient replacement capacity pose a significant reliability concern. Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are strictly contingent on securing firm replacement capacity to maintain reliability and meet a target winter reserve margin (e.g., 22%). If firm replacement resources are not in place, coal retirements would be deferred to preserve system reliability. Planning entities actively manage these risks by conducting thorough transmission impact studies to evaluate the effects of retirements on system reliability and to determine required transmission upgrades and replacement generation before allowing retirements to proceed.

Thirdly, the evolving interdependencies with other critical infrastructure sectors, especially natural gas fuel supply, are a major reliability issue, particularly during extreme weather conditions. The risk to BPS reliability from natural gas generator fuel supply issues, such as production or transportation

curtailments, is a recognized concern. Mitigation measures include ensuring that natural-gas-fired combined-cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Coordination protocols exist between electric and natural gas operators for both routine operations and emergency response, including maintaining electric service to critical gas infrastructure like compressor stations. Long-term studies also factor in fuel supply constraints and infrastructure bottlenecks, drawing insights from past events.

Fourthly, the operational impacts of the changing resource mix, particularly the increasing penetration of VERs and IBRs, are actively being addressed. Stability assessments are routinely conducted as part of TPL-001 compliance and interconnection cluster studies to evaluate inertia and transmission stability. While results so far have not revealed significant stability concerns, further analysis, such as EMT modeling, may be conducted in identified weaker areas with lower inertia. Interconnection studies for IBRs now mandate the use of EMT models to evaluate their performance during disturbances (e.g., momentary cessation, fault ride-through) and ensure compliance with NERC standards and FERC Order 827. Additionally, ensuring sufficient flexible resources are available to meet expected system ramping needs is a key planning consideration, with triennial integration studies assessing the system's ability to integrate intermittent generation.

Finally, one entity highlighted that its southern system, which is closely interconnected with neighboring utilities, may face import constraints during the spring and fall shoulder seasons when generation outages are common. To mitigate this, the entity proactively coordinates major generation outages with neighboring utilities and prioritizes reliance on internal generation rather than market purchases during these vulnerable periods. For extreme cold weather, a specific temperature threshold triggers the inclusion of additional operational reserves in its planning process, supported by enhanced forecasting tools. While no widespread transmission-constrained areas have been identified in recent planning studies, new transmission projects are being evaluated and planned to enhance transfer capabilities in response to increasing load demands and potential coal plant retirements, indicating ongoing efforts to prevent future transmission-related reliability issues.

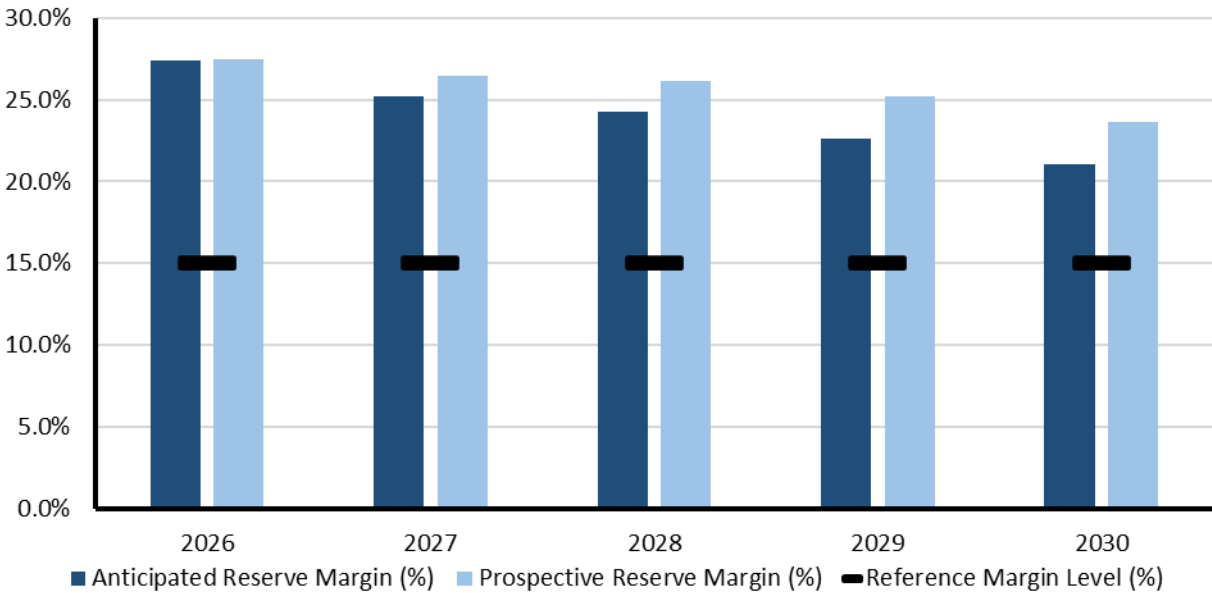


SERC-Florida Peninsula

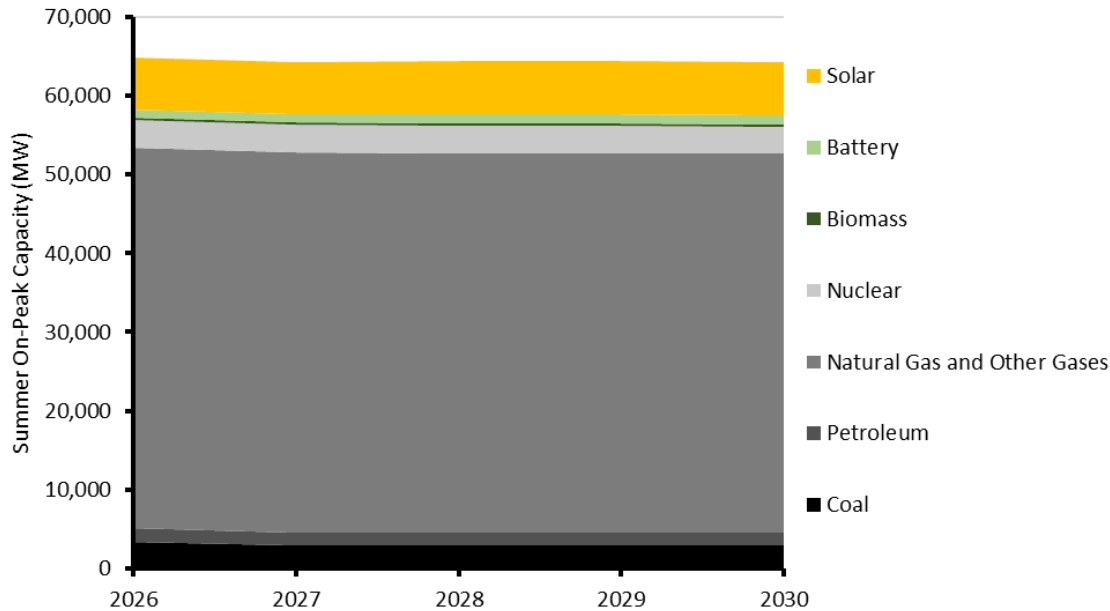
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across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

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	54,477	54,933	55,377	56,099	56,666	57,414	58,267	58,972	59,724	60,415
Demand Response	3,345	3,345	3,357	3,360	3,368	3,379	3,388	3,400	3,412	3,418
Net Internal Demand	51,132	51,588	52,020	52,739	53,298	54,035	54,879	55,572	56,312	56,997
Additions: Tier 1	754	800	997	1,000	1,001	1,801	1,801	1,802	1,803	1,803
Additions: Tier 2	32	620	962	1,375	1,375	1,375	1,375	1,375	1,375	1,375
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	293	293	200	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	64,393	63,795	63,659	63,659	63,525	63,001	62,966	62,966	62,966	62,966
Anticipated Reserve Margin (%)	27.4%	25.2%	24.3%	22.6%	21.1%	19.9%	18.0%	16.5%	15.0%	13.6%
Prospective Reserve Margin (%)	27.5%	26.4%	26.2%	25.2%	23.7%	22.5%	20.5%	19.0%	17.5%	16.1%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Florida Peninsula Highlights

- SERC-Florida Peninsula’s ARM falls below the RML during the 2035 time frame.
- SERC-Florida Peninsula’s ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	3,361	2,902	2,902	2,902	2,902
Coal*	3,346	2,418	2,418	2,418	2,418
Petroleum	1,795	1,667	1,667	1,667	1,667
Petroleum*	1,768	1,459	1,459	1,459	1,459
Natural Gas	48,214	48,202	48,159	48,159	48,025
Biomass	310	310	310	310	310
Solar	6,666	6,712	6,814	6,817	6,818
Nuclear	3,502	3,502	3,502	3,502	3,502
Battery	1,000	1,000	1,095	1,095	1,095
Total MW	64,849	64,297	64,450	64,453	64,321
Total MW*	64,806	63,604	63,757	63,760	63,628
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The Florida Peninsula subregion annually assesses its PRMs to ensure the regional total reserve margin (TRM) requirement is met over a 10-year projected period, considering summer and winter peak loads, generating resources, and firm DSM resources. The State of Florida’s Public Service Commission (FPSC) reliability criterion of a 15% reserve margin serves as the general TRM for entities in the subregion. Notably, investor-owned utilities (IOU) in the subregion voluntarily maintain a higher 20% reserve margin, which also functions as their RML based on firm load. These subregional TRM calculations incorporate merchant plant capacity that is under firm contract to load-serving entities.

Currently, the ARM for the Florida Peninsula subregion is projected to remain above the RML throughout the entire assessment period, indicating no present concerns regarding resource adequacy due to reserve margin deficiencies. Specifically, the projected Regional TRM is above the NERC RML of 15%, and Florida Peninsula subregion reserve margins are anticipated to stay at or above 20% for all summer and winter seasons during the assessment period. This healthy reserve level, coupled with excess import capability, means that the subregion does not foresee changes to its energy transfer needs or capabilities.

Probabilistic analyses confirm that the Florida Peninsula subregion continues to operate below this 0.1 loss of load probability (LOLP) standard. The methods used to calculate the Florida Peninsula RML have remained consistent since the prior LTRA. While individual planners account for uncertainty and variability before submitting their data, which is then aggregated, energy adequacy concerns are not directly addressed within the immediate calculation of ARM/RML. Instead, energy adequacy is reviewed through a biennial Loss of Load Probability Study, which assesses all hours of the year, as well as through transmission and fuel reliability study work. Although no formal changes have been made to existing resource adequacy planning or procurement processes since the 2024 LTRA, the Florida Reliability Coordinating Council (FRCC) and individual entities are actively considering enhancements, particularly focusing on the increasing penetration of IBRs to ensure sufficient dispatchable generation for potential energy assurance concerns. The FRCC is also continuing to develop its analysis of the 24-hour load and resource outlook around peak days to better understand the impact of increased solar penetration and energy storage charging/discharging on ARM/RML.

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

The Florida Peninsula Subregion undertakes energy risk assessments to understand its ability to meet uncertain forecasted system demand, particularly as traditional resource adequacy approaches face shortcomings with increasing variability. These assessments are primarily conducted through biennial loss-of-load probabilistic (LOLP) assessments, which are distinct from NERC’s ProbA and are designed to assess energy adequacy across every hour of a five-year study period, rather than solely focusing on seasonal peaks. Inputs for these studies include projected generating unit information (current and future capacity), seasonal demand values, projected DR availability, generation maintenance schedules, and Forced Outage Rates (FOR). The FRCC utilizes Astrapé’s SERVVM Software for multiple base case and sensitivity LOLP studies, with scenarios often examining conditions like no firm import availability, no DR availability, or a 90/10 load case.

These assessments review a 24-hour load and resource outlook centered around the peak day for both the summer and winter seasons. This effort helps entities fully comprehend the impact of increasing solar penetration levels and energy storage charging/discharging across all hours on the ARM and RML. The analysis has indicated no expected hours of shortfall in adequacy through 2034, though it has observed that increasing solar levels tend to shift the hours of thinnest reserve margins in the summer to later in the day (specifically, HE 18–19).

The FL-Peninsula subregion assesses system adequacy against the industry standard metric of 0.1 LOLP, which equates to approximately one event every 10 years, and currently remains under this standard. Although no significant adequacy impacts have been identified for off-peak hours and shoulder periods, the subregion entities are continuously working to improve their probabilistic analysis methodologies and enhance the robustness of their assessments for these periods. The results of these energy risk assessments are foundational for proactive planning, risk mitigation, and regulatory compliance, guiding long-term strategic decisions like infrastructure development and resource procurement, as well as short-term operational preparedness. The FRCC and its members are also actively considering enhancements to these processes, particularly focusing on the increasing penetration of inverter-based resources (IBR) to ensure sufficient dispatchable generation for potential energy assurance concerns.

ProbA Results

Based on the data and assumptions of SERC’s ProbA model, SERC-Florida Peninsula does not show any loss of load in 2027. For 2029, the annual, probability weighted risk is 0.094 MWh and the LOLH is 0.0001 hours. This is summarized in the table below.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	2	0	0.094
NEUE (ppm)	0.01	0.00	0.00
LOLH (hours per Year)	0.01	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

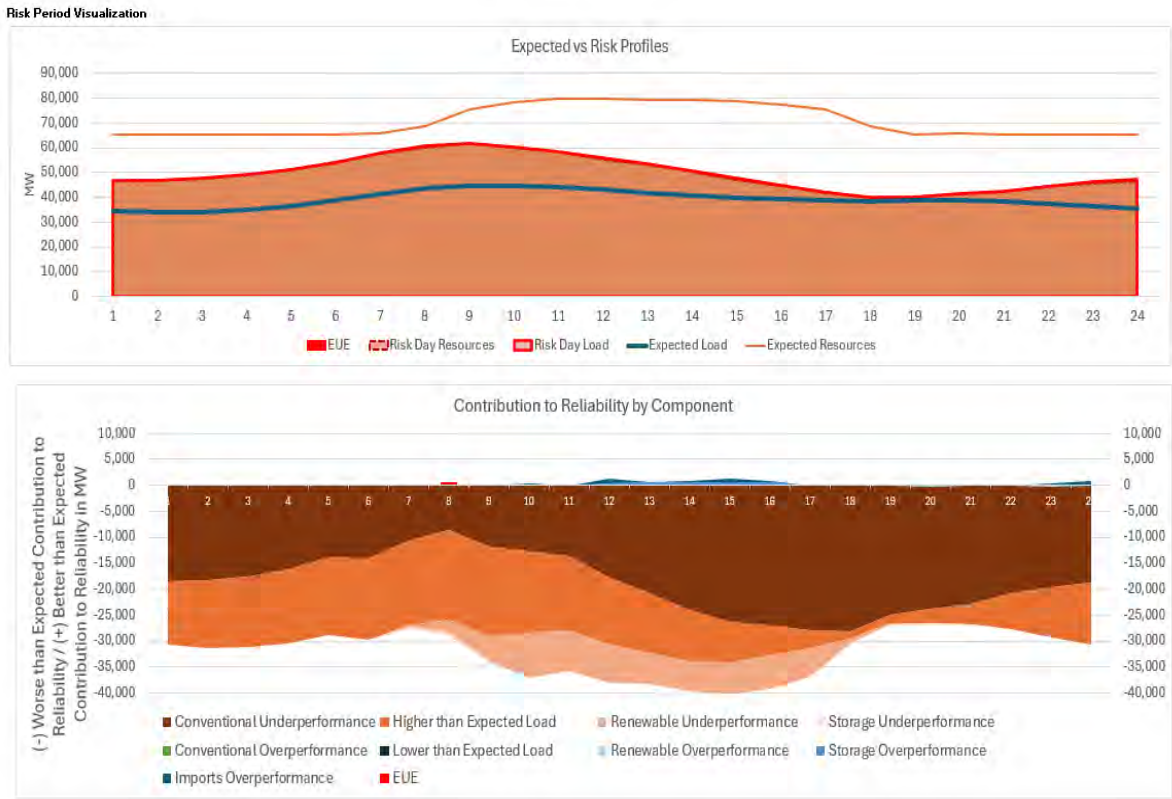
2027 EUE Heat Map

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2029 EUE Heat Map

As seen above, the 2027 EUE heat map does not show any risk hours. For study year 2029, there is only one out of 5,375 cases that show risk, which is for a load forecast error of +4%, and weather years 1985 which was an extreme winter year. For that one case, SERC-Florida Peninsula shows an EUE of 720 MWh, with all the risk in December at 7:00-8:00 a.m.

In the SERC SERVVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. Figures below show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029 show event details for one risk event for 2029.



Expected vs. Risk Profiles and Contribution to Reliability by Component

Above, the event day as higher than expected load (extreme winter 1985, 4% load forecast error) and resources available are less than expected. The above shows the risk hour to be between 7:00-8:00 a.m. when solar generation is limited, storage and imports are limited. There is some conventional generation on outage.

SERC-Florida Peninsula is also seeing load growth, with an addition of 1,551 MW winter load and 1,146 MW summer load between 2027 and 2029. While the subregion continues to add solar generation, this study indicates that it would not help alleviate risk in cases of extreme winter mornings when solar generation would be very limited.

With the heavy dependence on natural gas in the SERC-Florida Peninsula subregion, fuel diversity could become an area of future concern. Entities in FL-Peninsula have reported a high number of dual-fuel units to mitigate potential disruptions in the natural gas pipelines. Additionally, a new gas pipeline and connection hubs were constructed in the past few years to provide additional gas to the SERC-Florida Peninsula units. The growing penetration of renewable energy means that SERC and the SERC-Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.

Demand

The Florida Peninsula subregion’s approach to demand forecasting involves individual entities developing their own load forecasts, which are then aggregated by the FRCC to calculate a non-coincident seasonal peak for the subregion. These individual entities annually adjust their forecasts to account for factors such as actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and EE efforts, and electric appliance usage patterns.

The net energy for load (NEL) as well as summer and winter peak demands are forecasted to grow, with the current average annual growth rate for NEL at 1.1% per year, and firm summer and winter peak demand growth expected to increase to 1.34% and 1.45%, respectively, implying a declining trend for the regional load factor. While some larger utilities account for load profile modifiers like DERs and EVs, smaller utilities either lack sufficient data or deem their current impacts as minimal. The penetration of dependable ac solar capacity and EVs is currently low but expected to grow steadily. LFU is assessed at the individual entity level but is incorporated in FRCC and SERC probabilistic analyses for determining potential Loss-of-Load metrics, though not at the subregional level for Total Demand calculation.

Overall, demand and energy growth rates are projected to increase slightly (between 0.15% and 0.3%) compared to the previous LTRA, driven by population growth, economic performance, electricity prices, changing technology and consumption patterns, and more-efficient building codes. Higher-than-normal temperatures have played a noticeable role in higher average consumption per customer. The impact of data centers or similar large loads is currently minimal and not anticipated to create reliability concerns within the planning horizon, and insights beyond the 10-year forecast are not provided.

Demand-Side Management

DSM programs, controllable and dispatchable DR programs within the Florida Peninsula subregion are treated as a load modifier, projected to remain constant at approximately 6% of the summer and winter total peak demands throughout the assessment period. Each reporting entity independently

develops its forecast of firm controllable and dispatchable DR values based on their specific methodologies and program policies, with the FRCC aggregating these impacts for regional analytical purposes. In addition to utility-sponsored EE programs, many utilities also include forecasts of EE associated with the impact from governmental codes and standards. Trends in both utility-sponsored EE and EE from governmental codes and standards remain consistent with prior years, and no modifications have been made to these methods or assumptions since the previous LTRA. Looking forward over the next 10 years, while no changes to how EE and conservation are measured or accounted for have been implemented since the 2024 LTRA, enhancements are actively being considered. These considerations include improved hourly granularity, standardized methodologies, advanced measurement and verification techniques, and better integration of EE into long-term resource planning to support system reliability amidst growing energy demands and increasing renewable integration.

Distributed Energy Resources

The Florida Peninsula subregion systematically monitors and integrates DERs into its planning processes, primarily focusing on BTM solar PV as the most significant type of DER currently identified.

Penetration and Trends: The FRCC conducts an annual collection of DER data across its membership, as reflected in the Load and Resource Plan. While DER penetration levels, particularly for private dependable ac solar capacity and EVs, are currently relatively low, they are forecast to increase steadily over the planning horizon. This includes observed and anticipated year-over-year increases in BTM PV penetration, though these levels remain low compared to the total demand of the Florida Peninsula subregion.

Accounting and Integration in Planning: Entities within the subregion utilize NERC-published definitions for DERs. In general, DERs are modeled as being netted out with the actual customer demand, as their impacts are implicitly accounted for within the load forecasts developed by individual entities. Some larger utilities specifically account for DERs and EVs as load profile modifiers in their forecasts.

Monitoring and Studies: The FRCC’s Load Forecast Working Group (LFWG) meets annually to monitor trends in demand sensitivities related to DERs and coordinates on best practices. Additionally, resource planning, transmission planning, and stability analysis subcommittees annually review DER penetration levels to assess whether further study work or sensitivities are required.

Challenges and Reliability Impacts: No additional challenges or significant operational issues have been identified by PCs and Transmission Planners in the assessment area stemming from increased

DER penetration levels at this time. The subregion has not identified any significant BTM resources other than solar PV.

DER Aggregators: Currently, the FRCC and its members do not collect additional data from third-party DER aggregators beyond what is already included in the members’ integrated resource plans via their annual data collection process.

Generation

The Florida Peninsula subregion is actively managing its generation fleet to maintain reliability amidst an evolving resource mix, with a particular focus on the increasing integration of IBRs like solar and battery installations, and its continued reliance on natural gas.

Here are the key details regarding generation in the subregion:

- Changing Resource Mix and Operational Considerations:
 - While no significant operational issues have been identified at this time due to the changing resource mix, FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels (solar and battery installations).
 - The FRCC Operating Committee (OC) monitors actual output of solar units and tracks how much additional solar capacity will be online within the next 18 months, discussing any operational issues at monthly meetings.
 - Transmission planning studies, including short-circuit ratios and transient stability analyses, have been conducted to assess the performance of existing and planned IBR installations. These studies indicate that the FRCC system is anticipated to maintain reliable stability performance under expected IBR penetration levels in the five-year planning horizon, with no TPL performance issues identified.
 - Additional study sensitivities include light load conditions with solar modeled at projected output and system strength evaluations.
 - IBR performance issue risks are not considered significant in the near term for the assessment area relative to synchronous capacity.
 - The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.
- Natural Gas Reliance and Fuel Supply Risk

- The Florida Peninsula subregion is not expecting any long-term reliability impacts resulting from an increased reliance on natural gas-fired generation.
- The Fuel Reliability Working Group (FRWG) and Resource Subcommittee (RS) periodically study current and projected natural-gas-fired generation levels, including analyses of long-term infrastructure requirements, potential loss of compressor stations, availability of alternate fuel, and extreme weather analyses.
- Entities in the subregion do not anticipate natural gas supply issues to create reliability risk.
- Members are projected to hold the vast majority (approximately 90%) of firm pipeline capacity delivering into Florida, supporting increasing gas generation requirements.
- In the event of a short-term failure of gas delivery infrastructure, there is sufficient back-up fuel capability to meet projected demand. Approximately 55–57% of natural gas generation has alternate fuel capability.
- Communication protocols include fuel data status reporting by Operating Entities (OE) to the FRCC State Capacity Emergency Coordinator (SCEC) and FRCC RC during threats to fuel availability, integrating this data into enhanced daily capacity assessments.

Net Demand Ramping

No entity has identified any potential issues with net demand ramping within the 10-year planning horizon, as sufficient flexible resources are available. Potential ramping changes are not seen as emerging given current IBR penetration levels and the availability of dispatchable resources. FRCC planning and operating subcommittees plan to further evaluate aggregate system ramping needs over the next few years.

Capacity Contribution Values

Estimates for VERs, including wind, solar, and hydro, and energy storage, are determined by individual members based on actual performance of existing resources and projected performance using industry standard modeling tools (e.g., PVsyst).

Generator Retirements

Confirmed retirements are incorporated into the *Load and Resource Reliability Assessment Report*, while unconfirmed retirements are not tracked. Retirement decisions are made by each entity based on factors such as unit end of lifespan, operating costs vs. new alternatives, environmental regulations, and local sustainability targets. The subregion is not anticipating any negative impacts on reliability from retirements. Confirmed retirements projected have decreased from approximately 3,400 MW in the prior LTRA to 2,150 MW in the current analysis. Entities analyze projected resource

needs in their annual 10-year site plans (TYSP), which include planned retirements and new generation facilities.

Energy Storage

ES is increasingly being integrated into the planning processes within the Florida Peninsula subregion, with methodologies continuously evolving as entities gain more experience in their planning and operation. While entities are modifying their planning processes based on this accumulating experience, no significant modifications have been made to the core VER methods or assumptions, which include ES, since the previous LTRA.

For deterministic analyses, energy storage units are anticipated to be available to provide energy at the time of peak at their full capacity, effectively contributing to peak capacity. However, for probabilistic analyses and energy adequacy assessments, entities are continuing to discuss methodologies to incorporate supply duration and charging time to better reflect the resource's characteristics over time. The FRCC's biennial loss-of-load probabilistic assessments, which review every hour of a five-year study period, help assess energy adequacy and can include considerations for ES.

The impact of energy storage on system adequacy is also evaluated through the FRCC's "2x24 Hour Analysis." This analysis reviews the 24-hour load and resource outlook, helping entities understand more completely the impact of increased solar penetration levels and energy storage charging and discharging across all hours of the peak days on the ARM and RML. This detailed hourly assessment helps observe how ES operations influence system adequacy throughout the day and has indicated no expected hours of shortfall through 2034.

The capacity contribution values for energy storage are determined by individual members, generally based on a combination of actual performance of existing resources and projected performance using industry standard modeling tools. The basis for the percentage capacity contribution considers the nameplate rating of each facility.

Energy storage installations, particularly battery installations, are considered alongside other IBRs. FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels, including these battery installations. The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.

Currently, PCs and Transmission Planners in the assessment area have not identified any additional challenges or significant operational issues specifically stemming from increased DER penetration levels, including ES.

Capacity Transfers

In the Florida Peninsula subregion, capacity transfers primarily refer to anticipated firm import and export values with neighboring assessment areas, particularly the Southern Balancing Authority. While these transfers are an integral part of regional planning, Florida is generally not reliant on external capacity transfers for its core reliability, due to its robust internal generation and healthy reserve margins.

The FRCC Load and Resource Plan (LRP) annually incorporates anticipated firm import and export values reported by member utilities. Recent projections indicate a decline in firm imports for the region over the past few years.

To ensure effective capacity transfers and assess their sufficiency, the Florida–Southern Interface owners conduct an annual transfer capability assessment. This assessment determines the available transfer capability between Peninsular Florida and the Southern Balancing Authority and between the Southern Balancing Authority and FPL Northwest. The results of the most recent analysis project that the interface capability is sufficient to meet anticipated firm import needs.

Transmission

The Florida Peninsula subregion has not identified any specific major transmission projects that impact or are needed to maintain reliability during the planning horizon that are not already identified in the Annual Regional Plan. The individual entities have planned projects that are primarily related to system expansion in order to serve their forecasted growing demand and resource integration and to ensure long-term reliability (beyond the planning horizon). At this time, there have been no changes made to the transmission planning process since last year’s reporting.

Reliability Issues

The Florida Peninsula subregion generally maintains a strong reliability outlook, with no other significant emerging reliability issues identified at this time. The ARM is expected to remain above the RML throughout the entire assessment period, meaning there are no current concerns regarding resource adequacy related to reserve margin deficiencies and thus no reliance on Tier 2 resources or supplemental options. Similarly, no potential issues with net demand ramping have been identified within the 10-year planning horizon, and no additional challenges from increased penetration levels of DERs have been identified by PCs and Transmission Planners. Large industrial or commercial load additions, such as data centers, are not anticipated to create reliability risk in the subregion, nor have

any transmission-constrained areas been identified in planning studies. The subregion is also not reliant on external capacity transfers for its core reliability due to robust internal generation and healthy reserve margins.

Even though the Florida Peninsula subregion is not projecting any significant emerging reliability issues, there are areas that the assessment area continues to monitor closely and actively consider for future enhancements or reassessments, indicating underlying risks or concerns that could impact long-term reliability:

- **Increasing Penetration of IBRs and Associated Energy Assurance/Operational Flexibility Concerns:** Although IBR performance issues are “not considered significant in the near-term” for the Florida assessment area at current penetration levels, the increasing integration of IBRs (such as solar and battery installations) is a “key area of focus.”

- **Risks of Extreme Weather:** While the Florida-specific energy risk assessments note “no expected hours of shortfall,” scenario cases are run that include altered projected load to reflect extreme conditions (e.g., a 90/10 case), demonstrating an awareness of these potential risks.
- **Dependency on Natural Gas as a Fuel Resource:** Despite that Florida does not anticipate any natural gas supply issues that may create risk to reliability and has developed robust mitigation strategies (such as holding approximately 90% of firm pipeline capacity and having 55%–57% of natural gas generation with alternate fuel capability), the area’s “dependency on natural gas as a fuel resource” is still factor where possible impacts on the long-term reliability of the BES are continuously monitored.

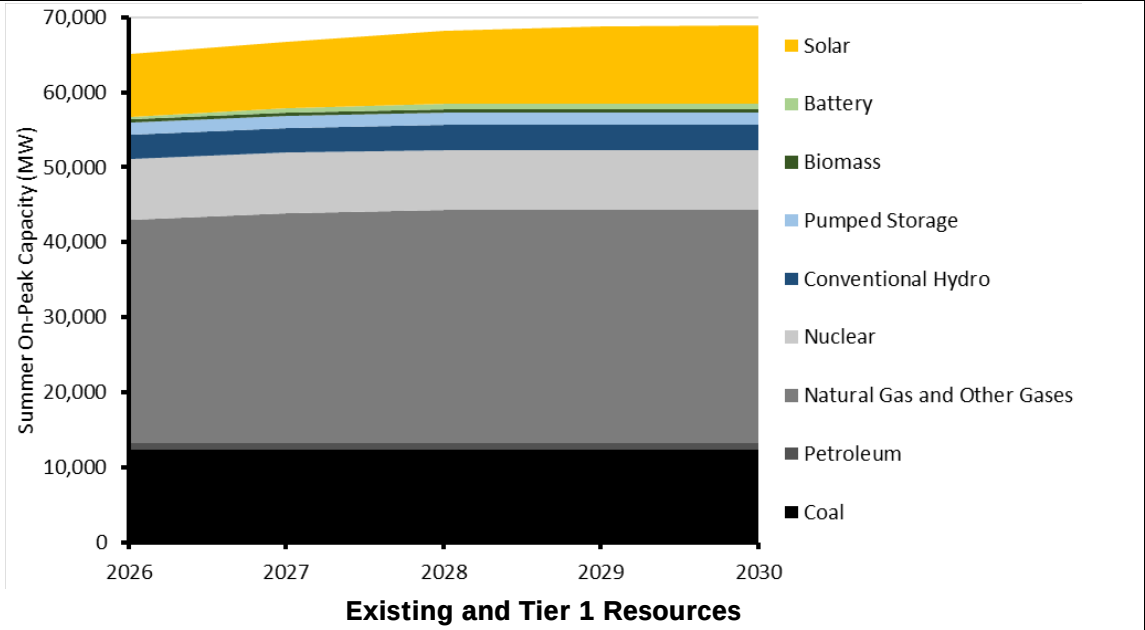
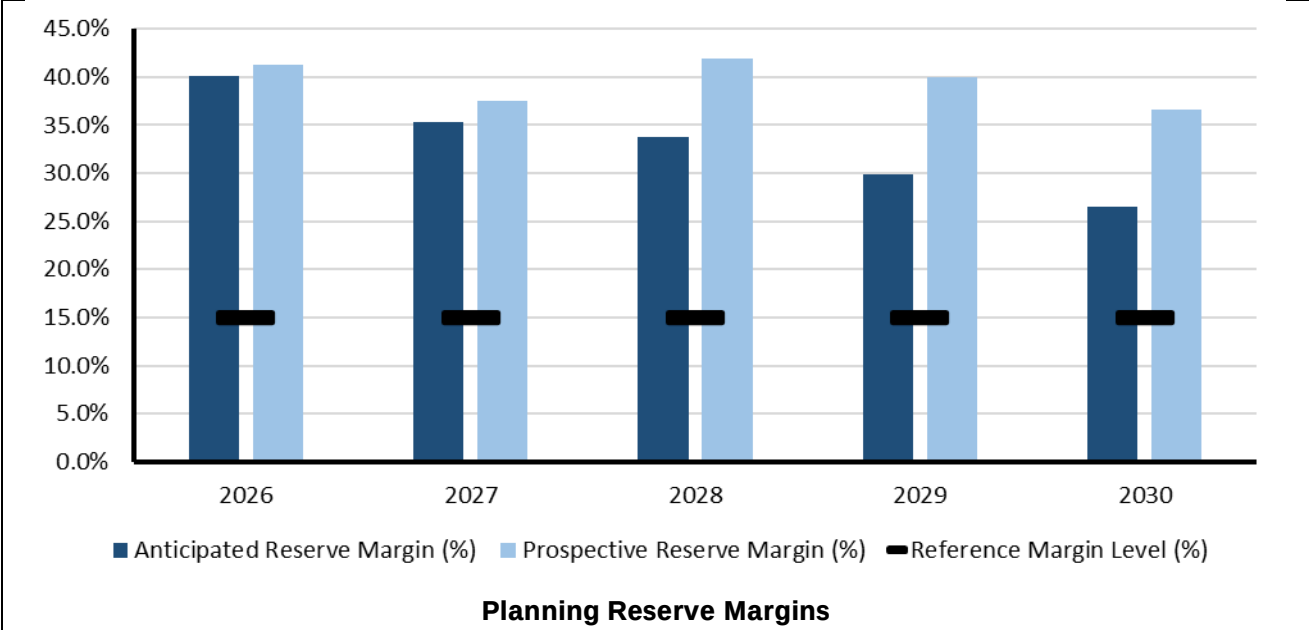


SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	48,386	50,648	52,900	55,127	56,624	57,544	57,978	58,552	59,004	59,166
Demand Response	1,358	1,391	1,623	1,634	1,640	1,650	1,656	1,664	1,671	1,677
Net Internal Demand	47,028	49,257	51,277	53,493	54,984	55,894	56,322	56,888	57,333	57,489
Additions: Tier 1	684	2,262	3,704	4,395	4,474	4,474	4,474	4,474	4,474	4,474
Additions: Tier 2	0	516	3,687	4,889	4,989	4,989	4,989	4,989	4,989	4,989
Additions: Tier 3	0	150	250	500	500	500	500	500	500	500
Net Firm Capacity Transfers	814	-53	414	619	619	619	619	619	619	619
Existing-Certain and Net Firm Transfers	65,201	64,393	64,860	65,065	65,065	65,065	65,065	65,065	65,065	65,065
Anticipated Reserve Margin (%)	40.1%	35.3%	33.7%	29.8%	26.5%	24.4%	23.5%	22.2%	21.3%	21.0%
Prospective Reserve Margin (%)	41.3%	37.5%	42.0%	40.0%	36.5%	34.3%	33.3%	32.0%	30.9%	30.6%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



SERC-Southeast Highlights

- SERC-Southeast’s ARM does not fall below the RML during the 2025–2035 time frame.
- SERC-Southeast’s ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	12,403	12,403	12,403	12,403	12,403
Coal*	12,403	12,403	11,145	11,145	11,145
Petroleum	866	866	866	866	866
Natural Gas	29,765	30,646	31,057	31,057	31,057
Natural Gas*	29,751	30,632	31,043	31,043	31,043
Biomass	428	428	428	428	428
Solar	8,358	8,836	9,667	10,358	10,358
Conventional Hydro	3,292	3,292	3,292	3,292	3,292
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	279	557	757	757	836
Total MW	65,042	66,678	68,120	68,811	68,890
Total MW*	65,042	66,678	66,862	67,553	67,632
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

PRMs in the Southeast assessment area highlight a proactive and stable approach to ensuring grid reliability, with ARMs projected to remain above reference or target levels throughout the long-term assessment period. Utilities in the region typically plan for a 15% reserve margin, a target that has remained unchanged from prior years. Capacity plans are specifically designed to maintain 15% reserve margins in summer and 25% in winter, consistent with previous long-term assessments. The annual IRP process is crucial, as it addresses resource adequacy well in advance, ensuring that reserve margins consistently stay above these required levels, considering both primary and secondary generation resources.

The methodologies for determining these RMLs are robust and comprehensive. A LOLP analysis is conducted to ascertain if adjustments are necessary to maintain a 1-in-10-year LOLE. This analysis relies on assumptions concerning system loads, potential outages, transfer capabilities, and resource plans, drawing from historical and forecasted data. To account for uncertainties, these assumptions are stress-tested through Monte Carlo simulations across a range of best- and worst-case scenarios, calculating EUE at current RMLs. One utility, which operates independently of state regulatory oversight, conducts its own triennial reserve margin study (RMS) to pinpoint an economically optimal reserve level. This RMS balances capacity costs, production costs, and the costs associated with unserved energy, utilizing a wide array of data including weather variability, unit reliability, fuel availability, and market conditions to model hourly system operations and assess the risk and cost of potential capacity shortfalls. Furthermore, resource adequacy assessments are evolving to include advanced capacity accreditation methods like perfect capacity (PCAP) and ELCC, which more accurately reflect the reliability contributions of VERs. For instance, one ELCC study increased solar peak credit from 50% to 89% for certain solar capacity. No significant changes have been made to reserve margin modeling or resource procurement processes since the previous LTRA, and none are planned for the next decade regarding resource adequacy planning, though input assumptions are regularly updated.

Despite maintaining adequate reserve margins, energy risk assessments highlight an important nuance: reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also crucial. Results from these assessments may prompt policy updates or recalibrated targets for PRM policies to better align with actual risk levels identified across the year, including non-peak hours. To address identified capacity needs or potential shortfalls, the IRP process leads to procurement actions approved by regulatory commissions. New resource technologies are selected based on their technical, economic, and capacity attributes. For example, one utility intends to maintain its 15% reserve margin by incorporating potential capacity purchases of up to 370 MW to

serve anticipated data mining loads over the next four years, alongside plans to add solar and battery resources in 2029. Overall, planning entities consistently update their capacity expansion plans annually to meet load requirements and adhere to these PRMs.

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

Energy risk assessments in the Southeast assessment area utilize a combination of deterministic and probabilistic methods to identify and address potential energy shortfalls across various planning horizons. These assessments incorporate crucial assumptions about fuel availability, generation outages, extreme weather events, and transmission capabilities. Winter peak hours have been identified as the highest-risk period for energy shortfalls, driven primarily by volatile peak demand during extreme cold weather events that exceeds forecasts, and sustained overnight load where demand remains high throughout the evening and early morning, eliminating traditional off-peak troughs. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours.

A significant finding from these assessments is that fuel availability, particularly for natural gas, presents a risk, especially in systems with limited renewable penetration. Entities are mitigating this by securing firm pipeline transportation contracts for baseload plants and ensuring onsite fuel storage (natural gas or fuel oil) for peaking units. Probabilistic modeling, including Monte Carlo simulations, evaluates the impact of these drivers, calculating metrics such as LOLE and EUE; these studies show increased risk in winter and significant EUE increases under fuel-constrained scenarios. Crucially, the results underscore that reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also vital.

Furthermore, scenarios modeling low hydro output and low solar generation during high-demand periods (especially in winter or prolonged cloudy conditions) indicate increased energy risks when variable energy resources (VERs) underperform. While annual production cost simulations performed in an “island” mode (excluding market purchases) have not identified energy deficiencies under base conditions, the RMS provides a comprehensive probabilistic analysis of hourly energy adequacy by simulating thousands of scenarios and considering historical weather, load, solar availability, fuel constraints, and generator outages. The RMS also assesses regional interdependency risks, finding that transmission constraints can hinder economic and emergency imports, exacerbating local energy shortages during widespread events. Energy risk assessments reflect a maturing focus on year-round, all-hour reliability, emphasizing risks from fuel supply chains, weather variability, and the increasing integration of variable renewable energy sources. These findings may lead to policy updates or recalibrated targets for PRM policies (e.g., 15% summer/25% winter) to better align with actual identified risk levels.

ProbA Results

SERC-Southeast does not show any loss of load risk for the year 2027, the EUE is 0.00 MWh and LOLH is also 0.00 hours. For the year 2029, there is a small ANNUAL risk of 0.39 MWh and 0.001 hours.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0.0	0.4
NEUE (ppm)	0.00	0.00	0.001
LOLH (hours per Year)	0.00	0.00	0.001
* Provides the 2024 ProbA Results for Comparison			

The figure below shows the EUE as a Heat Map for the year 2027.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

2027 EUE Heat Map

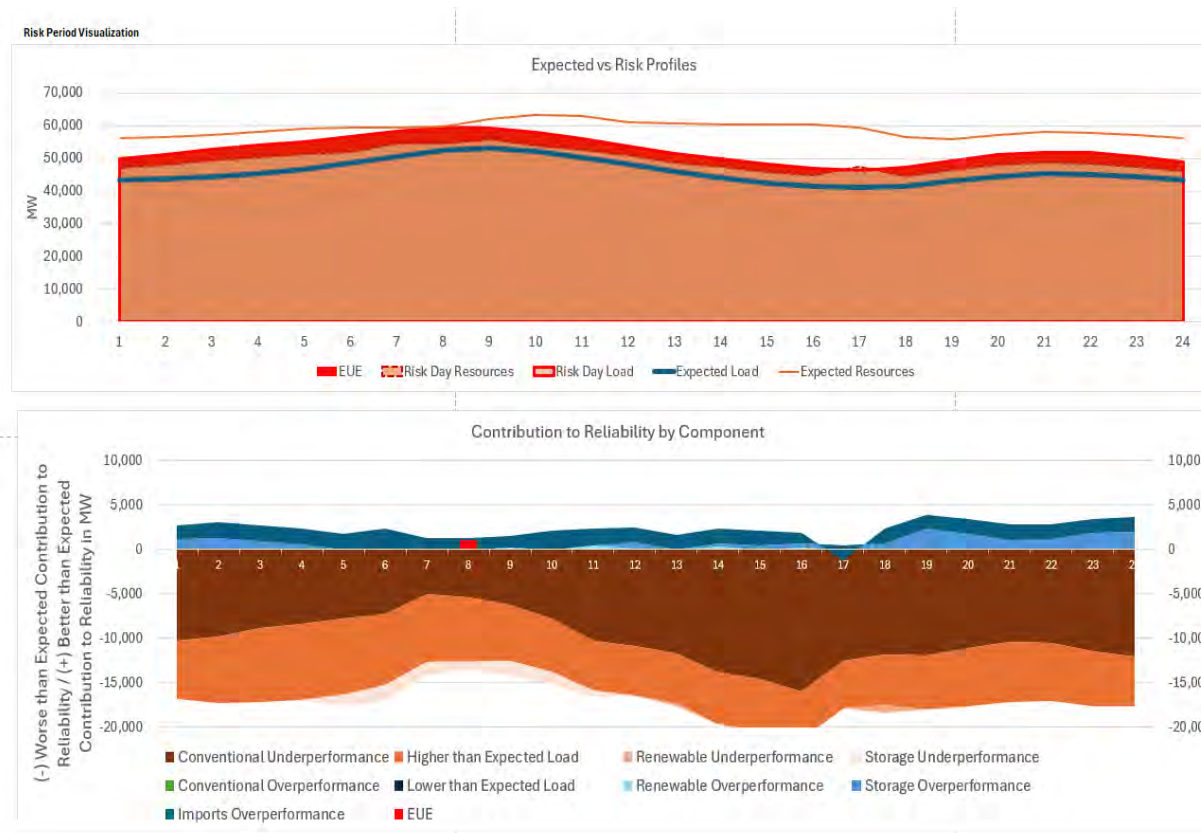
For the year 2029, there is a small annual risk of 0.39 MWh and 0.001 hours. There are some iterations of cases in the 2029 case, for load forecast error +2% and +4%, there is an EUE of up to 1,006 MWh. As shown in the figure below, higher load forecasts, particularly during extreme cold weather events such as weather years 1982, 1985, and 2022, contribute to risk in winter mornings (7:00-8:00 a.m.) and nights (10:00 p.m.-12:00 a.m.). December shows the most risk, followed by January.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	13%	29%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	1%	35%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	22%	0%	0%

2029 EUE Heat Map

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1000 event or higher probability, so the event day with the highest EUE in an hour was selected. Figures below

show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029.



The top figure compares the event day to a typical day in December, with weather year 1985, which was an extreme cold event. The lower figure shows the loss of load between 7:00-8:00 a.m. when the load is higher than projected, solar generation is unavailable, energy storage and imports are available during the risk hour.

Between 2027 and 2029, SERC-Southeast is expected to add battery and solar generation Tier 1 resources. The addition of solar generation, however, would not help alleviate risk that occurs in winter morning or winter night hours when solar irradiation is unavailable. Georgia Power Company has publicly filed their intent to build company owned combined cycle, battery energy storage systems, hybrid solar and battery energy storage systems, coming online between 2029 and 2031. However, the commission has yet to vote on approval, expected to do so in December and are not included in the model. SERC-Southeast is not expected to retire additional generation during this time.

SERC-Southeast is seeing high load growth. Between summer 2027 and 2029, there is expected to be an addition of 4,468 MW of summer load and 2,134 MW of winter load.

With the growing dependence on natural gas as the predominant energy source in the SERC Southeast subregion, fuel diversity could become an area of future concern.

Demand

The entities in the Southeast assessment area employ a robust approach to developing their load forecast for the LTRA. This methodology combines econometric modeling, statistically adjusted end-use (SAE) analysis, and hourly bottom-up aggregation across members. Forecasts are annually updated based on historical data and the latest S&P Global economic outlook, using regression models that account for weather, economic indicators, population, appliance efficiency, and load shapes. Both coincident and non-coincident peak demand forecasts are included and refined using specialized tools. LFU is addressed by testing load levels ranging from 80% to 104% of projected peak demand, with weather identified as the primary driver of variability. While DERs like rooftop solar currently have minimal impact, their potential effects are considered in sensitivity scenarios. No major changes have been made to the core forecasting methodology since the prior LTRA, though input assumptions are regularly updated.

Several factors contribute to the 10-year forecasted demand and energy growth rates. Data centers are a significant and highly uncertain consideration, capable of substantially increasing demand when included as a sensitivity in reliability studies, with nearly 400 MW of data mining load expected by 2025. These loads often exhibit unpredictable behavior, with some shifting to 24/7 operation, flattening the overnight load curve and extending peak periods, which complicates traditional peak-centric planning. Large commercial and industrial loads are expected to contribute to energy growth in specific economic development areas. Electrification trends are emerging slowly, with limited current impact on forecasts, though home heating electrification is notably contributing to increased winter peak sensitivity. Beyond the 10-year horizon, transportation electrification is anticipated to become a more significant driver of load growth. The influence of climate change and extreme weather on load forecasting is modest in most cases, with some utilities refining models to reflect more frequent cold weather patterns. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours. EE improvements are occurring but are not yet deemed a significant overall impact, and flexible or price-sensitive loads are typically modeled on the supply side, thus excluded from direct demand forecasts.

Demand-Side Management

Depending on the entity, DSM could be a voluntary DSM water heater program, which allows for limited control of appliance usage during peak demand periods, with the number of installed control switches tracked monthly to forecast future participation. Load research data is used to estimate the diversified load contribution from these devices. While the entity is monitoring how new EE regulations may impact program effectiveness and developing a DSM measurement and verification (M&V) framework, its analysis currently relies on historical load research data. DR resources under contract are monitored and dispatched, and annual ELCC simulations determine the capacity value of each active DR program. BTM DERs are accounted for within annual load forecasts, while front-of-the-meter (FTM) DERs are treated as generation assets. The entity is also exploring new DR and flexibility programs, including pilot efforts in commercial and industrial automated DR and solar-plus-storage, and implementing a DERMS to enable broader coordination. No modifications to DR methodologies or assumptions have been made since the 2024 LTRA, but new pilot programs and system capabilities are actively being developed. For EE and conservation, no significant changes have occurred in measurement or accounting since the prior LTRA. EE impacts are generally incorporated through adjustments to load forecasts based on federal and state efficiency standards, appliance saturation trends, and building code updates, reflected in econometric models or end-use forecasts that estimate reduced energy consumption over time.

Distributed Energy Resources

The estimated penetration of DERs in the Southeast assessment area remains modest, with forecasts projecting 1–1.5% of peak load over the next five years and staying below 2% over a 10-year horizon. Specifically, BTM solar PV is expected to grow from 57 MW by 2030 to 120 MW by 2035. Currently, DERs and rooftop solar are considered to have minimal impact on overall reliability, with no emerging transmission or resource adequacy issues directly attributed to them anticipated for Summer 2025.

In terms of planning, BTM DERs are accounted for within annual load forecasts and are not explicitly modeled as discrete capacity resources. Instead, they are represented using hourly generation profiles to account for operational factors like ramping, and estimated generation is placed back onto load buses when installations reach or exceed 2 MW. Conversely, FTM DERs are treated as generation assets. While BTM solar is contributing to energy availability and reducing fossil fuel consumption, their limited capacity value and variability are creating challenges, particularly during the sunrise and sunset hours, requiring greater flexibility from non-solar resources. Solar-related ramping concerns and energy adequacy under evolving weather conditions are considered emerging reliability challenges, which are actively being studied through triennial renewable integration studies. Load forecast uncertainty related to DERs is addressed by considering their potential effects in sensitivity scenarios, such as assuming zero DER contribution under stress conditions.

Generation

The Southeast assessment area actively manages its generation portfolio to ensure reliability amid a changing resource mix, with particular focus on the increasing integration of utility-scale solar and other VERs. While current renewable penetration is modest, leading to no significant stability or inertia issues observed to date, future challenges like intra-hour volatility and ramping needs are being proactively evaluated. The Renewable Cost and Benefit (RCB) Framework is utilized to assess integration costs and identify mitigation strategies such as flexible backup resources.

Regarding net demand ramping, the assessment area does not currently identify any emerging issues due to the limited penetration of VERs and a robust, flexible generation portfolio primarily composed of natural gas units. Annual analysis of five-minute ramping data is conducted to inform regulating reserve requirements, and existing natural-gas-fired units, supported by firm fuel supply and fuel-switching capabilities, are deemed sufficient to meet current and projected ramping needs.

Capacity contribution values for VERs like solar and wind are determined using a combination of historical performance data and ELCC analyses via the SERVIM reliability and production cost model. For solar, contributions are initially set at 50% of nameplate capacity during May–September, with annual re-evaluation based on actual performance, though no contribution is assigned in winter due to the assessment area’s winter peak planning season. An ELCC study in 2024 notably increased solar peak credit for up to 340 MW of solar capacity. While energy storage resources are evaluated through ELCC, with a preferred minimum duration of two hours, no operational storage resources are currently on the system. Hydro resources are credited at 100% due to firm delivery contracts.

Efforts to address IBR performance issues include enhanced interconnection studies that assess various factors like thermal loading, voltage stability, and short circuit performance. EMT models are now required from Generator Owners to better simulate and understand IBR behavior during disturbances, and mitigations include adjusting ramp rates and enforcing ride-through requirements. Additional phasor measurement units (PMU) are being deployed to enhance real-time situational awareness, particularly at IBR interconnection points. While current IBR penetration is low, network impacts and protection coordination are identified as the primary reliability concerns being addressed.

Generator retirements have seen no changes to confirmed or unconfirmed projections since the *2024 LTRA*, with no unit retirements currently projected over the 10-year planning horizon. All native generation, including coal, natural gas, and nuclear resources, is expected to remain available to meet peak demands. Planning entities have established processes involving detailed studies over a 10- to 20-year horizon to assess potential reliability impacts of retirements, considering mitigations such as transmission infrastructure capital improvements or dynamic VAR support. The IRP process

coordinates retirement schedules with the addition of replacement capacity to prevent reliability gaps.

Natural gas fuel supply risk is actively managed, with approximately 78% of winter on-peak natural gas generation capacity having either firm fuel supply arrangements or backup fuel options like oil or dual-fuel capability. Annual gas pipeline failure studies are conducted ahead of each summer and winter season to assess impacts under various curtailment scenarios. Communication protocols between electric system operators and natural gas operators are maintained for coordinated responses. Long-term planning processes incorporate fuel risk through load capability analysis and production cost modeling over a 20-year horizon, ensuring capacity plans meet PRMs.

Energy Storage

While there are currently no operational energy storage resources on the system in the Southeast assessment area, future plans do include the addition of solar and battery resources by 2029. BESS are recognized as IBRs that, like solar, require different modeling and analysis techniques compared to traditional synchronous generation. The uncertainty surrounding the future locations and generation outputs of new BESS is noted as a factor that complicates proactive planning.

For planning purposes, energy storage resources are primarily evaluated for their capacity contribution through ELCC analyses. A preferred minimum duration of two hours is considered for operational reliability when evaluating energy storage resources, although there is no formal duration requirement currently enforced. Pilot programs are also being explored, specifically solar-plus-storage initiatives, as new DR and flexibility programs. These programs aim to provide flexible capacity and fast-start capabilities to the system.

No major methodology modifications have been made to the methods or assumptions for incorporating energy storage since the *2024 LTRA*.

Capacity Transfers

Capacity transfers are important for reliability in the Southeast assessment area and the SERC Region. System adequacy is maintained through planning studies and coordination with neighbors to manage evolving energy needs and maintain regional reliability.

Currently, surplus capacity for transfer and delivery is anticipated to remain available to meet reliability margins and support marketing opportunities. Transmission flow patterns are becoming more dynamic due to shifts in internal and external resource portfolios, retirements, additions, and system topology adjustments, but no significant impacts to firm transmission contracts have been

identified to date. Furthermore, recent reserve margin studies suggest that current transmission capabilities do not pose a constraint on resource adequacy within the assessment area.

To facilitate and ensure reliable capacity transfers, the assessment area engages in extensive coordinated efforts, studies, and protocols with neighboring assessment areas for both peak and non-peak hours. These coordinated efforts include:

- **Joint Transmission Planning Studies**, such as the Southeast Regional Transmission Planning (SERTP) process, which evaluate the BPS’s ability to support transfers under various seasonal and system conditions, accounting for projected load growth, generation changes, and transmission upgrades.
- **Firm Transfer Agreements and Modeling**, which are integrated into seasonal and long-range planning studies to ensure deliverability under normal and contingency conditions. These agreements are regularly reviewed and updated.
- **Seasonal Coordination Studies**, including power flow, stability, and transfer capability analyses, conducted prior to each summer and winter season to assess the ability to maintain reliability and meet transfer obligations under expected and extreme conditions.
- **Contingency and Emergency Protocols** with neighboring BA and Reliability Coordinators to support emergency situations and real-time transfers. These protocols are exercised through reliability drills and supported by tools like dynamic line ratings and real-time data sharing.
- **Reserve Sharing and Balancing Arrangements** that enable entities within the assessment area to share generation reserves during system events or peak demand periods, supporting both operational reliability and economic efficiency.
- **Real-Time Operational Coordination** where neighboring areas monitor real-time flows and manage congestion through dynamic scheduling, redispatch strategies, and curtailment procedures as necessary.
- **Coordinated use of the Open Access Same-Time Information System (OASIS)** to ensure transparency and proper scheduling of transfers, preventing violations of reliability standards or operational issues.

Despite these robust coordination mechanisms, energy risk assessments have highlighted certain limitations regarding external reliance, particularly during extreme conditions. Studies, including the RMS, have modeled interactions with 13 neighboring systems to understand the limits of market support during high risk periods. These assessments indicate that regional transmission constraints can hinder economic and emergency imports, potentially exacerbating local energy shortages during widespread events. Furthermore, studies suggest limited excess market generation availability during

extreme weather events in the Southeast, underscoring the critical importance of internal resource adequacy planning.

In terms of future reliance, while the overall trend suggests sufficient internal capacity, one utility expects to potentially make capacity purchases of up to 370 MW to serve possible data mining loads over the next four years. This indicates a willingness to utilize external purchases to meet specific, potentially high-density and unpredictable, new loads. The results of energy risk assessments are used to inform capacity expansion plans and determine the need for additional capacity purchases.

Transmission

Entities within the assessment area have numerous transmission projects planned or underway over the next 10 years to support system reliability and address evolving load and generation needs. These projects include approximately 1,308 miles of new transmission lines above 100 kV, 1,322 miles of line rebuilds, around 20 reactive compensation installations, 50 new transmission stations, and various upgrades to increase the capacity of existing infrastructure. One entity plans to retire a 46 kV transmission path and convert affected delivery points to 115 kV service, constructing a new network line to address localized thermal constraints and improve contingency performance. Power electronic devices such as reactive compensation systems are being installed to enhance voltage stability and system performance. While no major transmission adequacy issues have been identified, there are risks of project delays due to supply chain disruptions and contractor availability. Mitigation measures include staggered project timelines, strategic inventory management, and evaluation of interim technologies like variable line impedance devices. Overall, the assessment area maintains a coordinated and proactive transmission planning approach to ensure continued reliability across the region. Since the *2024 LTRA*, planning entities across the assessment area have begun implementing or exploring several enhancements to their transmission planning processes in response to evolving reliability, resource mix, and regulatory conditions. One key area of focus is the growing presence of IBRs, such as solar and battery storage, which require different modeling and analysis techniques compared to traditional synchronous generation. Entities are now incorporating additional scenarios into their long-term planning to assess the adequacy of the transmission system under various levels of IBR penetration, particularly in areas experiencing rapid deployment of utility-scale renewables.

Another significant development involves planning for large data center loads, which present unique challenges due to their high energy consumption and sensitivity to power quality. Entities are preparing to implement new technical studies—such as dynamic modeling and harmonic analysis—to ensure that these loads can be reliably served without compromising grid stability. These studies are expected to become increasingly important over the next 10 years as data centers proliferate across the region. While there have been no wholesale changes to core transmission planning methodologies, adjustments are being made to better reflect recent operating experiences. For

example, entities have refined the load levels used in extreme case scenarios to align more closely with observed peak events. There is also growing interest in performing comprehensive gas-electric interdependency studies to assess the risks posed by natural gas supply disruptions to gas-fired generation resources.

For non-FERC-jurisdictional entities, FERC Order No. 2023 is being monitored, and although compliance is not mandatory, potential alignment with its principles—such as improved generator interconnection procedures and enhanced transparency in queue management—is being considered.

Regional coordination remains a critical component of transmission planning. Entities continue to work closely with first-tier neighbors through long-term, quarterly, and weekly coordination protocols. Interface transfer capabilities are calculated regularly on monthly and two-day-out bases, with requests managed through the OASIS system. Coordination of transfer capability assessments and planning assumptions is also carried out through interregional forums, such as the SERC Long-Term and Near-Term Working Groups and the Southeastern Regional Transmission Planning process. These efforts ensure that planned projects and operational practices are aligned across the region, helping to maintain reliability as system conditions evolve.

Reliability Issues

The Southeast assessment area actively manages its generation portfolio to ensure reliability amidst a changing resource mix. While no significant stability or inertia issues have been observed to date due to the current modest renewable penetration, several evolving reliability concerns are being proactively addressed:

- **Elevated Winter Energy Risk and Sustained Overnight Loads:** Energy risk assessments consistently identify winter peak hours as the highest-risk period for energy shortfalls. This

increased risk is driven by two primary factors: volatile peak demand due to extreme cold weather events exceeding forecasts, and sustained overnight load where demand remains high throughout the evening and early morning. Recent winter events, such as Winter Storm Elliott, have led to updated load shapes that reflect higher and more sustained loads, underscoring the importance of energy adequacy beyond just peak periods. This indicates a shift requiring more continuous energy coverage rather than just peak-hour capacity.

- **Natural Gas Fuel Supply Vulnerability:** Fuel availability, particularly for natural gas, has emerged as a significant energy risk. To mitigate this, entities in the assessment area actively manage natural gas fuel supply risk through firm fuel arrangements, backup capabilities like onsite fuel storage or dual-fuel options (e.g., oil), and annual gas pipeline failure studies conducted before each summer and winter season. Communication protocols are also maintained between electric and natural gas system operators for routine and contingency operations. Long-term planning studies also incorporate considerations for gas production limitations and transportation bottlenecks.
- **Challenges Posed by Large Industrial and Commercial Load Additions:** The assessment area is experiencing an increasing demand of large industrial and commercial load additions, such as data centers and crypto mining facilities, which require enhanced coordination, especially with local distribution cooperatives. These loads can “substantially increase demand” and exhibit unpredictable behavior, with some shifting to 24/7 operation and relying on short-term capacity purchases. Entities are proactively developing updated technical interconnection requirements and pursuing regulatory approvals to procure additional generation to serve these new loads.

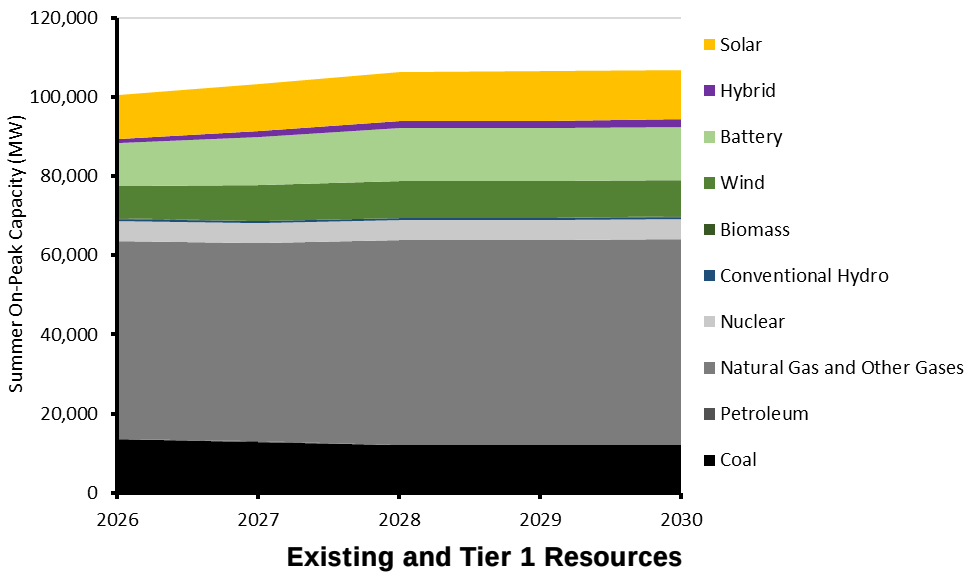
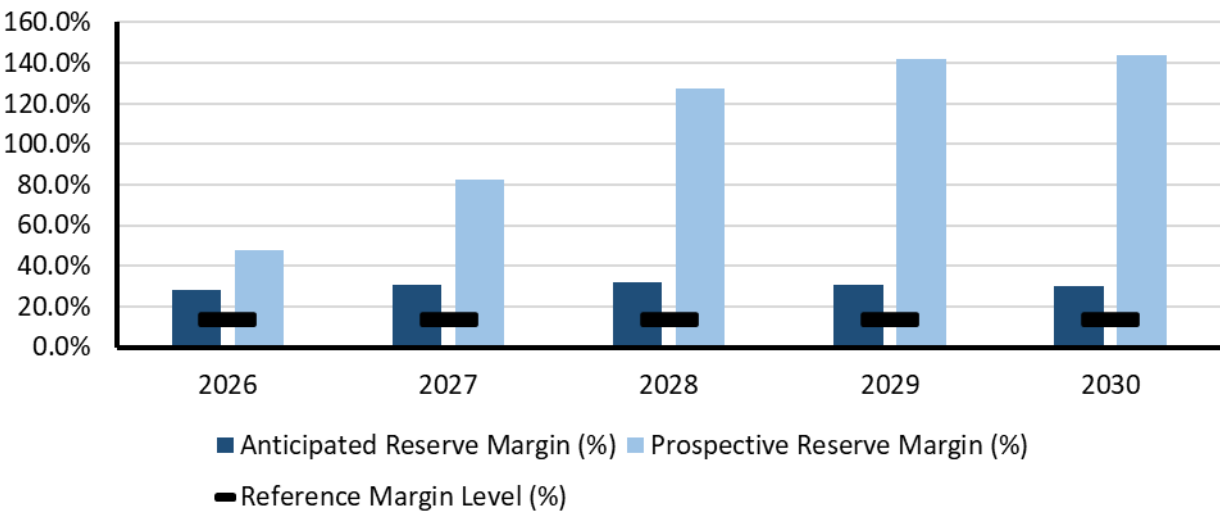


Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Reliability Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	94,650	104,295	121,543	128,851	138,944	144,522	148,567	149,846	152,230	154,077
Demand Response	13,346	22,127	37,672	43,888	53,131	57,720	60,942	61,846	62,644	63,321
Net Internal Demand	81,304	82,168	83,871	84,963	85,813	86,802	87,625	88,000	89,586	90,756
Additions: Tier 1	10,377	15,216	18,527	19,037	19,037	19,037	19,037	19,037	19,037	19,037
Additions: Tier 2	15,391	42,413	79,923	95,374	98,707	99,018	99,018	99,018	99,018	99,018
Additions: Tier 3	5,022	17,546	36,405	51,080	58,217	58,217	58,463	58,463	58,463	58,463
Net Firm Capacity Transfers	508	659	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122
Existing-Certain and Net Firm Transfers	93,870	92,008	92,046	92,113	92,401	92,401	92,401	92,401	92,401	92,401
Anticipated Reserve Margin (%)	28.2%	30.5%	31.8%	30.8%	29.9%	28.4%	27.2%	26.6%	24.4%	22.8%
Prospective Reserve Margin (%)	47.9%	82.3%	127.3%	142.1%	143.9%	141.5%	139.2%	138.2%	134.0%	131.0%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Texas RE-ERCOT Highlights

- The ARM is above the 13.75% RML for all years and seasons and reflects the inclusion of provisional forecast estimates of large-load curtailment potential, applicable before and during ERCOT emergency conditions.
- ERCOT forecasts total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%.
- Texas Senate Bill 6, signed into law in June 2025, provides ERCOT with new large-load curtailment management tools and the authority to direct large loads to curtail their load both prior to and during declared energy emergency situations.
 - Offsetting the positive ARM impact of these load management programs is the switch from using historical average on-peak capacity factors to average ELCC for IBRs.
- ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026, growing to 25.2 GW by 2029, which reflects the furthest future year for reported planned commercial operations dates.
- ERCOT's 2024 Regional Transmission Plan (RTP) includes a 345 kV plan and the Texas 765 kV Strategic Transmission Expansion Plan (TX 765-kV STEP), which addresses unprecedented load growth expected by 2030.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	13,596	12,941	12,156	12,156	12,156
Coal*	13,596	12,550	11,205	11,205	11,205
Petroleum	30	30	30	30	30
Natural Gas	50,032	50,122	51,689	51,689	51,977
Natural Gas*	50,032	49,764	51,331	51,331	51,619
Biomass	131	131	131	131	131
Solar	11,049	11,923	12,305	12,534	12,534
Wind	8,303	8,900	9,215	9,219	9,219
Conventional Hydro	570	570	570	570	570
Nuclear	4,973	4,973	4,973	4,973	4,973
Hybrid	1,127	1,497	1,813	1,909	1,909
Battery	10,734	12,285	13,375	13,374	13,374
Total MW	100,545	103,372	106,257	106,584	106,872
Total MW*	100,545	102,203	104,528	104,855	105,143
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					
**Wind, solar, and battery capacities are based on their projected effective load carrying capabilities during peak load conditions.					

Texas RE-ERCOT Assessment

Planning Reserve Margins

The ARM is above the 13.75% RML only for summers 2026 and 2027, and winters 2025–26 and 2026–27. The main contributing factor for lower ARMs relative to last year’s LTRA is the switch from using historical average on-peak capacity factors to average ELCC for IBRs. In the case of solar, ELCCs are significantly lower than on-peak capacity factors since ELCCs reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low. Partially offsetting the reduction in solar contribution was the shift from assigning 0% on-peak capacity contribution for battery energy storage to using average ELCCs based on design duration. For example, battery storage systems with a duration of one hour or less are assigned an ELCC of 36%, whereas the ELCC for systems greater than one hour and less than two hours is 69%.

Energy Risk, Including Non-Peak Hour Risk

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at HE 9:00 p.m.—based on probabilistic capacity reserve modeling for monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. However, the large growth in battery energy storage resources and associated changes in state of charge management have mitigated the capacity reserve scarcity risk relative to previous years. For winter, risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 to 9:00 a.m.) as well as the early evening hours.

Probabilistic Assessments (NERC ProbA and Other Studies)

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	11,090	5,864	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.94	3.64
* Provides the 2024 ProbA Results for Comparison			

Like the 2024 ProbA Study, most risk is in the winter, and this is mainly driven by the large demand variability modeled in the winter. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year.

12x24 EUE Heat maps (months for the vertical axis, hours for the horizontal axis) for 2027 and 2029 are provided below. Note that as the numbers are given in percentages, the lower winter values in 2029 relative to 2027 do not indicate a decrease in winter risk, just a smaller portion of the annual total.

2027

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	4%	3%	2%	2%	3%	5%	8%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	7%	5%	4%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	2%	2%	2%	2%	2%	3%	4%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	4%

2029

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	3%	2%	2%	2%	3%	4%	6%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	4%	4%	4%	3%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	4%	1%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%	5%	1%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	1%	1%	1%	1%	1%	2%	2%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%	2%	2%	2%

Demand

ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads, comprised mostly of data centers. The breakdown of new large loads added by 2030 by customer classification is as follows:

Load Additions in the Load Forecast (MW) (Cumulative)			
Load Type	End of Year 2 (2027)	End of Year 5 (2030)	End of Year 10 (2035)
Data Centers	6,700	23,000	25,000
Cryptocurrency Mining Facilities	4,500	7,500	8,500
Hydrogen Electrolysis	3,000	7,902	9,100
Industrial Manufacturing Load	2,800	7,100	7,600

For 2025, the ERCOT transmission service providers (TSP) had once again reported a significantly larger-than-normal amount of contracted large loads that they asked to be included in the *2025 Long-Term Load Forecast* and *Regional Transmission Planning Study*. Due to the large amount of large-load requests for 2025, ERCOT has applied adjustment factors to these requests. ERCOT has adjusted the large-load projections provided by the TSPs based on the patterns observed by recent projects. The first adjustment was based on the average project delay of 180 days from the original project requested energization date for projects with in-service dates in 2022 through 2024. The next adjustment was applied to Data Centers. ERCOT studied requested MWs versus the peak consumption by data center site for data centers with in-service dates in 2022 through 2024. The average peak consumption per site was 49.8% of the requested MW. This factor was applied to all non-crypto data center load additions. The final adjustment used the percentage of previously filed officer letter projects with in-service dates in 2024 that have energized (55.4%). This percentage is based on percentage of loads energized.

The PUCT is developing criteria for including large loads in ERCOT’s load forecasts along the lines of criteria applicable to generation projects (for example, the large-load customer has executed and securitized an interconnection agreement or meets other criteria demonstrating a firm commitment to interconnecting the load).

Demand-Side Management

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and ERCOT’s authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. The following table shows the total large loads and their curtailment amounts included in the “Controllable and Dispatchable Demand Response” line items.

Summer	Total LL (MW)	LL Curtailment (MW)	Winter	Total LL (MW)	LL Curtailment (MW)
2025 (S)	3864.4	1,313.9	2025-26 (W)	9112.9	8,227.7
2026 (S)	12355.4	8,853.5	2026-27 (W)	17289.8	15,909.3
2027 (S)	21665.7	17,171.5	2027-28 (W)	31590.8	29,408.9
2028 (S)	38583.3	32,716.5	2028-29 (W)	45249.3	42,298.1
2029 (S)	45681.1	38,932.6	2029-30 (W)	55533.1	51,981.4
2030 (S)	55964.9	48,175.5	2030-31 (W)	60917.9	57,010.6
2031 (S)	61349.7	52,764.3	2031-32 (W)	64863.6	60,672.7
2032 (S)	65295.4	55,985.9	2032-33 (W)	66370.5	62,017.8
2033 (S)	66802.3	56,890.6	2033-34 (W)	67764.7	63,256.0
2034 (S)	68196.5	57,688.4	2034-35 (W)	69032.1	64,373.6
2035 (S)	69463.9	58,365.6	2035-36 (W)	69805.1	65,043.3

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member Transmission and Distribution Service Providers (TDSPs) to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year time frame.

ERCOT has proposed rule changes mandated by the Texas Legislature to establish a process to collect comprehensive data from Distribution Service Providers for so called “Unregistered Distributed Generators” (primarily rooftop solar systems). The data will be collected on a substation level and will include information to be used for network modeling and analysis, including aggregate reactive power capability and status of PUCT voltage/frequency ride-through requirements.

Generation

In 2024, ERCOT received notices of suspension of operations for three gas-steam units in the San Antonio area. Reliability impact studies indicated that all three were needed to manage the South Texas Interconnection Reliability Operating Limit (IROL) established in 2024. As a result, ERCOT signed

a two-year “Reliability Must Run” (RMR) agreement with CPS energy for one of the three generators (Unit 3). This generator, as part of its RMR service obligation, would only operate when necessary to provide voltage support, stability, or management of localized transmission constraints when a market solution does not exist. ERCOT also signed a contract in June 2025 to use 15 mobile generators that are being relocated from Houston to the San Antonio area. The contract ends in March 2027 when transmission solutions are expected to be in place to offset the loss of the mothballed CPS generating units.

New rules became effective in October 2024 to improve IBR ride-through performance and monitoring and mitigation efforts. The rules were developed in response to NERC recommendations following IBR failures during system disturbances in West Texas. The new ride-through requirements align with the specifications of the updated IEEE 2800-2022 standard, which addresses the interconnection and interoperability of IBRs. As part of the new rules, IBR entities are required to maximize their IBR ride-through capabilities, which includes making software, firmware, and settings adjustments, and potentially physical modifications to ensure that they can remain connected to the grid during frequency and voltage disturbances. The rules also establish a process for investigating, reporting, and mitigating ride-through performance failures, requiring resource entities to develop mitigation plans within a defined timeline. IBR entities must meet the new requirements by December 31, 2025, or their synchronization date, subject to an extension/exemption process.

During 2024, units totaling 18.6 MW were retired, comprising a 9.6 MW biomass facility, a 7 MW wind site, and 2 MW battery storage system. So far in 2025, a 62 MW gas combined-cycle unit was retired.

Energy Storage

ERCOT expects battery energy storage capacity to reach 18.9 GW by summer 2026 (Existing and Tier 1 resource categories). The capacity grows to 25.2 GW by 2029, which reflects the furthest future year for planned commercial operations dates reported by project developers.

ERCOT is moving away from a dual to an integrated single model of an energy storage resource for operational and transmission planning studies. Under the dual approach, an energy storage resource is composed of a generator with a negative minimum power to represent consumption and a generator with a positive maximum power to represent injection. The single “integrated” generator model, along with other system enhancements for battery energy storage, is being implemented as part of ERCOT’s “Real Time Co-Optimization + Battery” project, expected to be implemented by December 2025. Since each resource receives independent dispatch instructions and ancillary service deployments in the dual model approach, moving to a single integrated resource model will eliminate current performance monitoring issues. The discharging behavior for all energy storage resources is considered for peak cases in transmission planning studies. The charging behavior for all energy

storage resources is considered for minimum load cases in transmission planning studies. Energy storage resources, if required to provide voltage support, need to have the reactive power capability be available at all MW levels when charging or discharging and meet the voltage ride-through requirements to remain connected to the system. To support larger penetration levels of energy storage resources, new rules have been implemented to improve state-of-charge monitoring in energy dispatch and Reliability Unit Commitment.

Capacity Transfers (Reliance on Assistance)

ERCOT has coordination plans in place with neighboring grids. These plans cover DC tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers. For its transmission planning studies, ERCOT tests the outage of each of the ERCOT-SPP DC ties, plus a contingency on top of that, to ensure no reliability issues post-contingency. There are no severe scenarios studied where multiple DC ties are assumed to be unavailable.

Transmission

ERCOT’s 2024 RTP includes a 345 kV plan and a 765 kV plan, called the Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP). The 765-kV plan tackles the unprecedented load growth expected by 2030 and associated regional planning challenges and addresses existing congestion issues. TX 765-kV STEP enhances transfer capability by an additional 600 to 3,000 MW across various scenarios evaluated in the analysis and would also increase the West Texas export stability constraints. The 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers. Overall, 274 reliability projects were identified in the 2024 RTP’s 345 kV plan to address all reliability violations compared with 173 projects in the 2023 RTP, 89 projects in the 2022 RTP, 67 projects in the 2021 RTP, and 50 projects in the 2020 RTP. This upward trend reflects grid infrastructure needed to support rapidly growing power demands and an evolving generation resource mix.

ERCOT is adopting changes to its planning processes to address the long-term transmission challenges. Examples of the major changes include establishment of a new congestion cost savings test for economic project evaluation, establishment of resiliency criteria for the ERCOT region, and development of new multi-value criteria to address the process for determining whether a project that addresses a resiliency issue provides sufficient benefit balanced with economic savings or reliability benefits.

Reliability Issues

There are several reliability concerns associated with the rapid growth in large loads:

Loss of Load: Due to the amount of large electronic-based load projected to energize in upcoming years (mainly from cryptocurrency mining facilities), ERCOT is concerned that potentially thousands of megawatts of load can instantly drop or switch to backup generation during normally cleared system faults, thereby posing significant risks to system reliability. To address this concern, ERCOT has proposed a change to its Reliability Performance Criteria to limit load loss for any single contingency and to specify how loss of load is calculated for this criterion. ERCOT recently completed a Load Loss Threshold Analysis that indicates that the load loss should be limited to 2,600 MW.

Load Forecasting Challenges: The flexible operation of large loads also presents challenges for accurate load forecasting and monitoring. ERCOT has observed increasing errors in its load forecasts, which is problematic during extreme or unusual operating days when having an accurate forecast is most critical for maintaining reliability. New approved rules include standards for the identification and classification of a site with an aggregate peak demand of 25 MW or more at a common substation in ERCOT’s Network Operations Model. Such information will provide ERCOT visibility of the locations of these loads for operational, modeling, and planning purposes.

Potential Subsynchronous Oscillation Vulnerabilities: Large loads, particularly those with high reactive power consumption, can cause subsynchronous oscillation (SSO) that can damage generation and other equipment and ultimately destabilize the grid. This vulnerability is highest in areas with a weak grid, such as West Texas. To address SSO issues, ERCOT is implementing new rules that require SSO vulnerability assessments for large-load customers seeking grid interconnection as well as for transmission projects.

Need for a Large Load Interconnection Study Process: ERCOT identified the need for a Large Load Interconnection Study (LLIS) process several years ago due to the emerging reliability impacts. An interim process was estimated in March 2022. A final interconnection process was approved by the PUCT in May 2025.

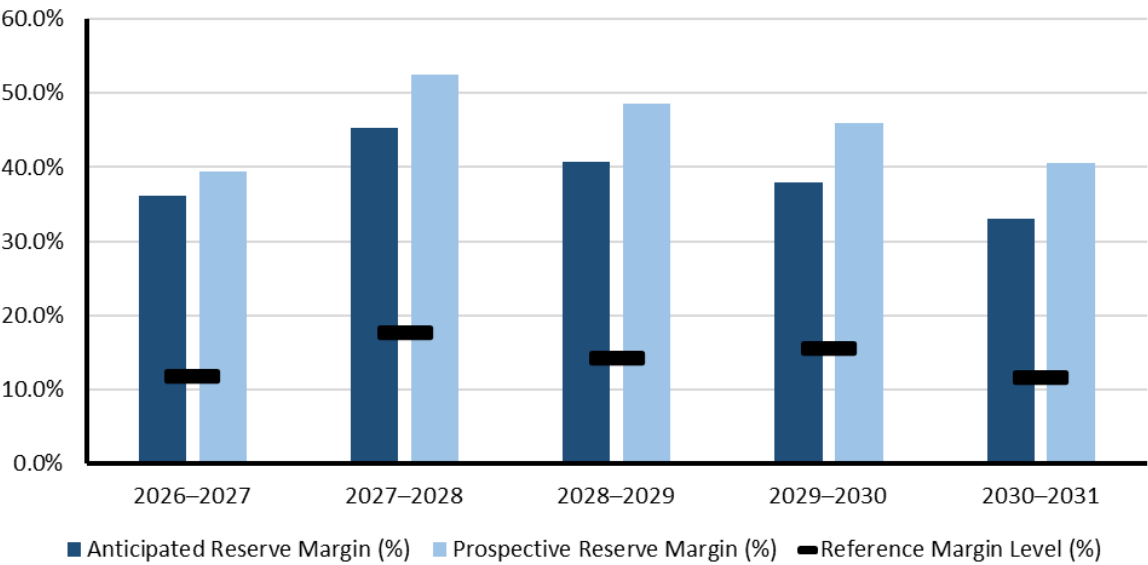


WECC-Alberta

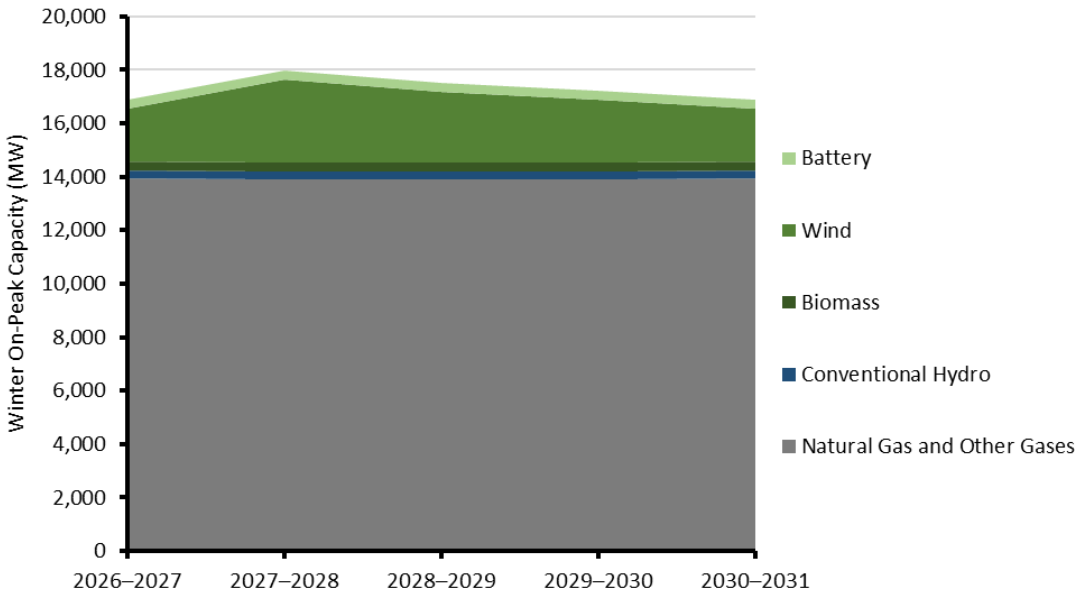
WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province’s Planning Entity and Reliability Coordinator 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.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Additions: Tier 1	209	209	209	209	209	209	209	209	209	209
Additions: Tier 2	393	889	983	1,009	959	1,009	921	971	971	971
Additions: Tier 3	392	658	917	1,297	1,334	1,631	1,635	1,751	1,751	1,751
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	16,764	17,856	17,394	17,074	16,764	17,074	16,502	16,820	16,820	16,820
Anticipated Reserve Margin (%)	36.2%	45.3%	40.7%	38.0%	33.0%	34.7%	29.0%	31.1%	30.2%	26.4%
Prospective Reserve Margin (%)	39.3%	52.4%	48.6%	46.0%	40.5%	42.6%	36.1%	38.5%	37.7%	33.6%
Reference Margin Level (%)	11.8%	17.6%	14.3%	15.6%	11.6%	15.2%	12.2%	14.3%	13.9%	13.5%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Alberta Highlights

- WECC-Alberta’s ARM does not fall below the RML during the 2025–2035 time frame.
- WECC-Alberta’s total electricity demand is projected to grow by 10% over the next 10 years. Summer peak hour demand is projected to grow by 7%, and winter peak hour demand is projected to grow by 11% over the same period.
- Alberta is anticipated to add 556 MW of Tier 1 gas, solar, and battery resources over the next 10 years. Alberta’s thermal power generation fleet is aging, and significant additions of Tier 2 and 3 variable renewable energy resources are being proposed to make up for forthcoming thermal retirements while meeting Alberta’s 30% renewable by 2030 policy requirement. On top of the 250 MW of existing storage, 88 MW are anticipated Tier 1 and 370 MW are Tier 2 additions over the next 10 years. Still, rapid declines in solar and wind output could cause ramping issues in the future and require the use of contingent reserves and assistance from the NWPP Reserve Sharing Group.
- AESO has recently added two transmission lines to its system to increase reliability and integrate fossil-fired generation additions.
- Under a different set of assumptions and with a different vintage of data from the LTRA, the NERC ITCS for Canada concluded that WECC-Alberta may have winter energy deficiencies that could be alleviated by increased transfer capabilities.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	13,932	13,908	13,890	13,900	13,932
Biomass	336	336	335	336	336
Wind	2,000	3,109	2,665	2,327	2,000
Conventional Hydro	293	301	301	310	293
Other	81	81	81	81	81
Battery	330	330	329	330	330
Total MW	16,973	18,065	17,602	17,283	16,973

WECC-Alberta Assessment

Planning Reserve Margins

WECC-Alberta’s ARM does not fall below the RML during the 2025-2035 time frame. WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1 day in 10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Canada Clean Electricity Regulations (CER) were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Alberta has recently entered into an agreement with the Canadian federal government to pursue alternative policies to achieve a net-zero power grid by 2050.

Energy Risk, Including Non-Peak Hour Risk

AESO uses an hourly probabilistic model to quantify uncertainties around unit availability, dispatch economics, load variability, and weather impact on load and generation in operational time frames.

ProbA Results

Alberta does not show any LOLH or EUE in 2027 or 2029 and therefore does not have any further reporting or visualizations.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

Demand

Alberta’s annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 7% and winter peak hour demand is projected to grow 11% over the same period. The primary driver for demand growth in Alberta is transportation electrification. Large-load additions in the forecast total 80 MW over the next five years and 105 MW through 2035. Additional large loads that may materialize and are not included in the forecast amount to 1,600 MW by 2030 and 2,100 by 2035.

Seasonally, the region is becoming more dual-peaking with summers almost matching winters.

Demand-Side Management

AESO factors in approximately 250 MW of DSM in its load forecast and this is projected to remain steady across the 10-year assessment period.

Generation

Alberta is anticipated to add 556 MW (nameplate capacity) of Tier 1 gas, solar, and battery resources over the next 10 years. Tier 2 additions include nearly 5 GW of gas, solar, wind and batteries and Tier 3 additions include just over 5 GW of gas, solar, wind, conventional hydro, and batteries. Operational and planning issues related to generation in WECC-Alberta include the following:

- Aging Thermal Resource Fleet: There is ongoing analysis of potentially mothballing aging coal-to-gas boilers. Alberta has five natural gas steam sites over 35 years old, which total 1,745 MW of capacity. Alberta shows significant additions of Tier 2 and Tier 3 solar and wind to make up the difference. Supply shortfalls are addressed using the protocols in AESO’s ISO Rules. These protocols include directives such as instructing available assets and long-lead-time assets to deliver energy up to their maximum capability, calling upon DR, and maximizing import capability.
- Solar and Wind Variability: Rapid decline in solar and wind output coupled with off-line thermal resources can create situations in which thermal resources cannot be ramped up in time to counter the loss of renewable generation. The use of contingency reserves coupled with a subsequent grid alert declaration to receive assistance from the NWPP Reserve Sharing Group (NWPPRSG) are options for addressing these situations.
- Electric-Gas Coordination: As a part of WECC’s load and resources data request, members were asked to provide a conservative estimate of the percentage of natural gas generating capacity that is likely to have firm supply for 2025 and 2030 for both the summer and winter season. Results indicated that all natural-gas-fired generators connected to AESO’s system are fueled through firm gas supply contracts during both the summer and winter seasons but do not report any dual-fuel capacity. To enhance operational reliability of natural gas fuel supplies for the province, Alberta’s natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events impact the gas supply and transportation system. There is frequent communication between system operators regarding gas resources

that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

- Resource Portfolio, Clean Electricity, and Development Policies: The Canadian province of Alberta is required to ensure its electricity supply is [30% renewable by 2030](#). Alberta has also issued a ban on renewable energy project development on prime agricultural land and a buffer zone around pristine views, both of which could limit siting for wind and solar. This followed a temporary moratorium from August 2023 to March 2024 on new renewable approvals, creating investment uncertainty. In January 2025, Alberta lifted a previous 2022 moratorium on coal exploration, reopening 190,000 hectares of land to new coal development.

Energy Storage

In addition to the 250 MW of existing energy storage in Alberta, 88 MW are anticipated Tier 1 additions, and 370 MW are projected Tier 2 additions of energy storage over the next 10 years. Storage in the west is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

Energy Transfers

According to the NERC's [ITCS Canadian Analysis](#), the total simultaneous transfer capability into the Alberta transmission planning region from all its neighbors, including dc-only interties, is 1,096 MW in 2024 Summer and 1,005 MW in 2024–25 Winter. These values translate to approximately 10% of peak summer load and 9% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Montana (see WECC-Northwest) and British Columbia (see WECC-British Columbia).

The ITCS for Canada further showed that WECC-Alberta may have winter energy deficiencies that can be alleviated with increased transfer capabilities.

Transmission

In 2024, Alberta added two transmission lines for fossil-fired integration. The reported primary driver for transmission expansion in Alberta is reliability.

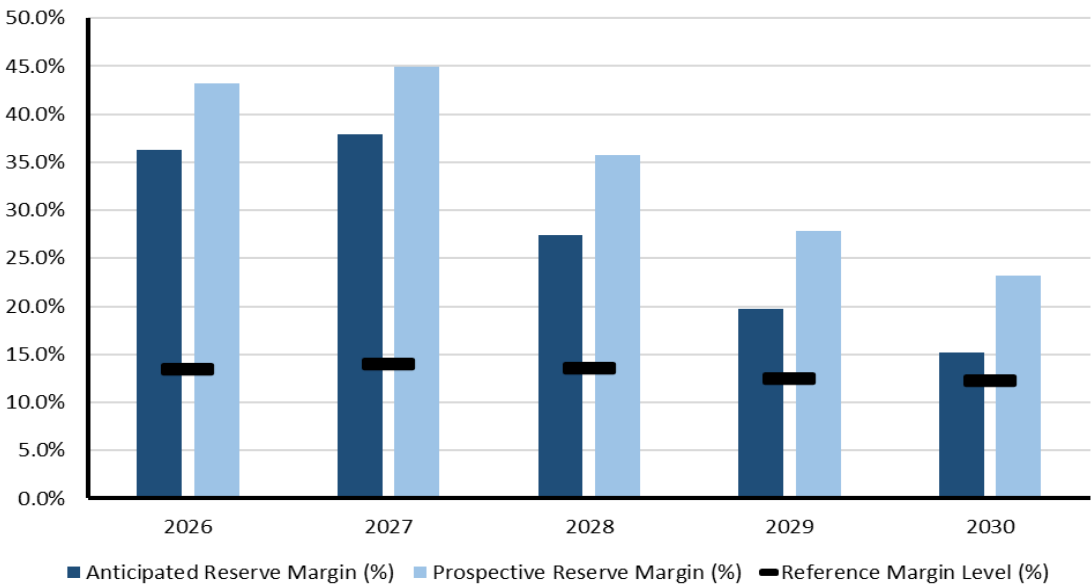


WECC-Basin

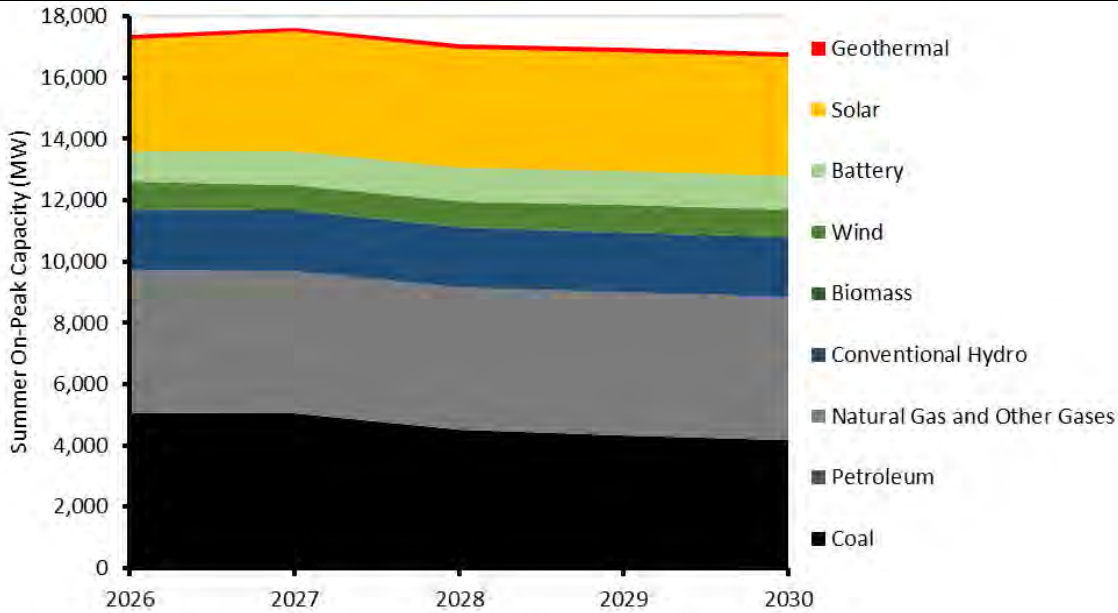
WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp’s eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is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

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	14,794	15,326	16,012	16,396	16,762	17,099	17,202	17,268	17,344	17,467
Demand Response	670	670	670	670	670	670	670	670	670	670
Net Internal Demand	14,124	14,656	15,342	15,726	16,092	16,429	16,532	16,598	16,674	16,797
Additions: Tier 1	2,125	2,453	2,453	2,466	2,466	2,466	2,466	2,453	2,466	2,466
Additions: Tier 2	973	1,018	1,270	1,279	1,279	1,279	1,279	1,270	1,279	1,279
Additions: Tier 3	127	1,162	2,024	2,616	4,209	4,726	5,665	6,203	6,332	6,332
Net Capacity Transfers (WECC Model)	1,822	2,545	2,420	1,820	1,698	1,400	1,400	1,400	1,400	1,400
Existing-Certain and Net Transfers	17,125	17,763	17,097	16,357	16,071	15,736	15,729	15,315	15,288	15,280
Anticipated Reserve Margin (%)	36.3%	37.9%	27.4%	19.7%	15.2%	10.8%	10.1%	7.1%	6.5%	5.7%
Prospective Reserve Margin (%)	43.2%	44.9%	35.7%	27.8%	23.1%	18.6%	17.8%	14.7%	14.2%	13.3%
Reference Margin Level (%)	13.5%	14.0%	13.6%	12.4%	12.3%	12.1%	12.1%	12.5%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Basin Highlights

- The ARM does not fall below the RML during the 2025–2035 time frame. IPCO and PACE participate in the Western Resource Adequacy Program (WRAP).
- The Basin subregion shows three LOLH in 2027 totaling approximately 3 MWh of EUE in June and July at hours beginning 18:00 and 19:00. In 2029, the subregion shows 310 LOLH totaling approximately 200,892 MWh of unserved energy. Over 90% of the EUE occurs between the hours of 17:00–22:00 from June to September.
- For 2027 and 2029, the peak hour is projected to occur in July at hour beginning 15:00.
- The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

WECC-Basin Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	5,068	5,041	4,508	4,326	4,177
Petroleum	5	5	5	5	5
Natural Gas	4,655	4,634	4,634	4,655	4,655
Biomass	31	31	31	31	31
Solar	3,668	3,899	3,899	3,884	3,884
Wind	900	826	826	897	882
Geothermal	139	139	139	139	139
Conventional Hydro	1,962	1,976	1,968	1,954	1,954
Other	31	31	31	19	19
Battery	967	1,090	1,090	1,092	1,092
Total MW	17,428	17,672	17,130	17,003	16,839

WECC-Basin Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2026–2035 time frame. The Idaho Power and PacificCorp East balancing areas both participate in WRAP, the first regional reliability planning and compliance program in the West.

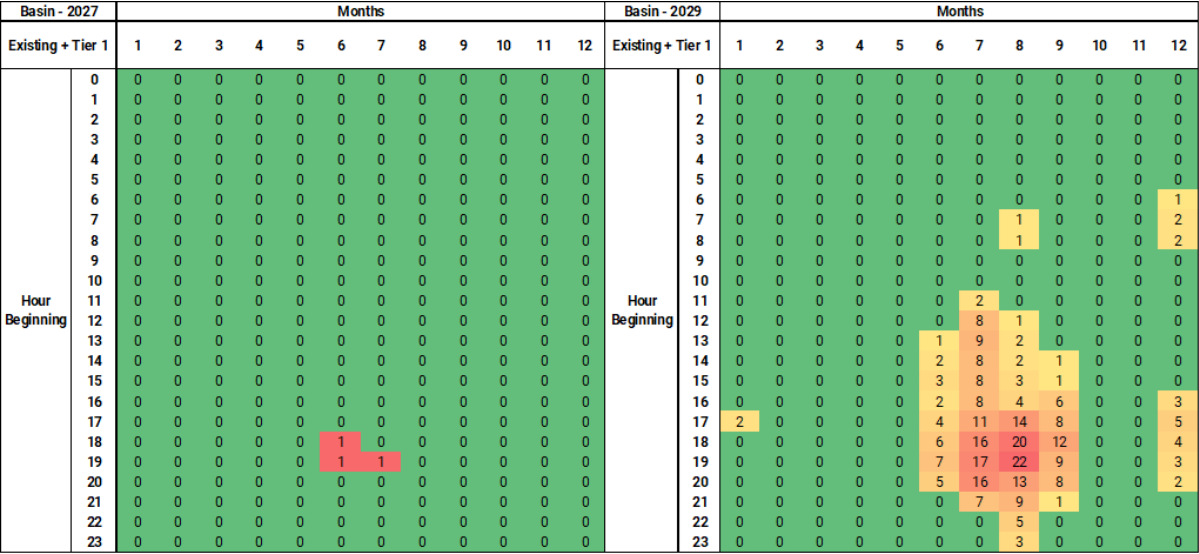
Energy Assessment, Including Non-Peak Hour Risk

WECC performs a probabilistic resource adequacy analysis using the Multiple Area Variable Resource Integration Convolution model (MAVRIC). MAVRIC is WECC’s internally developed modeling tool that performs energy based ProbAs that support NERC’s LTRA and seasonal assessments, as well as WECC’s Western Assessment of Resource Adequacy (WARA).

Although the WECC-Basin assessment area’s ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs after 2027, unserved energy and load-loss increase in the ProbA results. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

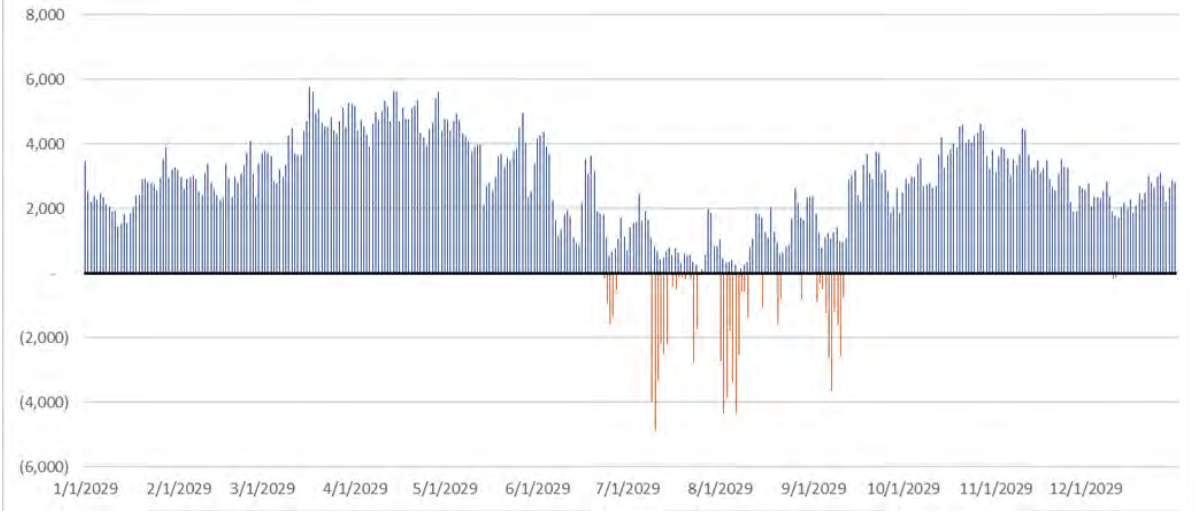
Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2250.70
LOLH (hours per Year)	N/A	3.00	310.00
* No prior results as the assessment area is new for the 2025 LTRA.			

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. In the ProbA results illustrated in the following heat map figure, risk is most concentrated to the month of peak demand (June) and the hours around sunset as solar output declines. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime.



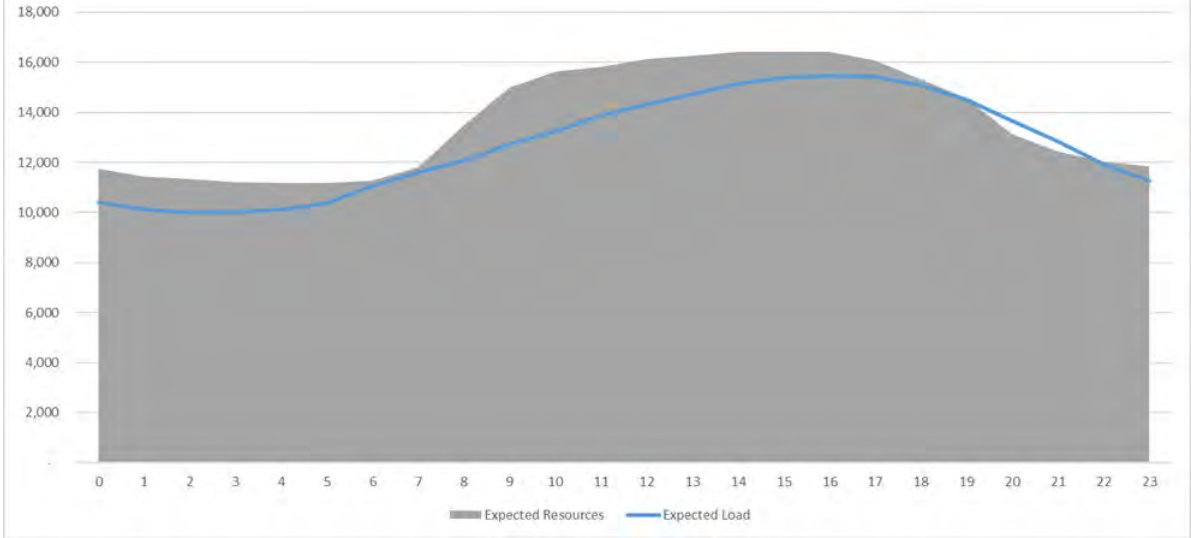
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Basin Assessment Area in 2027 and 2029

In WECC’s ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Basin has excess energy that can be transferred to neighboring areas. During peak summer months, however, more of WECC-Basin’s resources are needed for its own internal demand and, at times, energy deficits that must be met by importing energy from neighbors can exceed 4,000 MW.



Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. LOLH occurs at hour of 17:00 to 21:00 in 2029. This coincides with the evening solar down ramp and the persistence of elevated demand after the peak hour. The profile for the 2027 study year is similar but limited to the 18:00 to 19:00 hour. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Basin assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.



Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year

Demand

Average annual growth rate for Basin is 2.5%. The primary drivers are data centers and semiconductor manufacturing. Large-load additions in the forecast are 1,223 MW through 2035.

Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows the utility to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year-to-year based on factors such as the availability of water and program parameters. PacifiCorp states in its most recent IRP that it plans to reach more than 1,100 MW of dispatchable DR by 2042, a 21% increase from its previous plan. The company’s dispatchable DR programs include residential and small commercial air-conditioner load control programs, irrigation load management programs, and approximately 200 MW of evergreen interruptible contracts.

Distributed Energy Resources

BTM DER impacts are reflected in the demand forecasts (net of the DERs). BAs did not report a forecast for BTM resources.

Generation

Operational and planning issues related to generation in WECC-Basin include the following:

- **Aging Thermal Resource Fleet:** An aging thermal resource fleet is a year-round concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. Maintenance is planned years in advance and avoided during summer peak season as much as possible. Quarterly evaluations are done to adjust maintenance schedules as needed.
- **Gas Fleet Derates:** During the winter, gas resources may be derated during extreme cold and precipitation events for equipment issues such as snow-clogged inlet filters. This issue is remedied by monitoring filters and changing them out as needed.
- **Hydro Variability:** Hydro resources in this subregion are subject to seasonal and multi-year fluctuations in water supply. This is a year-round concern that requires persistent monitoring. Regular updates to near-term hydro forecasts ensure system operators can be ready for a range of potential hydro output.
- **Solar Variability:** As the solar capacity in this subregion grows, solar ramps are becoming a concern on summer evenings. Large declines in solar output require the dispatch of flexible resources to meet demand. In addition, during the winter solar generation tends to be significantly lower. BESS that typically charge from solar must charge from other resources. Wind and solar forecasts are used to estimate energy availability to serve load versus the amount available for BESS charging, and other resources are dispatched accordingly.
- **Wind Variability:** Particularly during the winter, the timing and volume of wind generation can vary significantly between forecasts and actuals. This is due to the unpredictable behavior of winter storms that may overspeed turbines, or cold temperatures mixed with moisture that may result in the icing of turbine blades.

Electric-Gas Coordination

Electric-gas coordination in long-term planning studies is considered for at least one Basin entity. For integrated resource planning assumptions, Resource Planners reach out to gas traders to confirm pipeline capability to serve existing and future generating asset needs. Gas supply constraints are not explicitly modeled but are inherently reflected in the GADs data used to develop long-term models.

Maintaining gas supplier diversity is one strategy implemented to reduce the risk of fuel shortages and delivery issues in this subregion. In addition, at least one entity in this subregion participates in the Northwest Mutual Assistance Agreement (NWMAA). This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving those resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

Idaho Power serves ~63% of the state's electricity load and is targeting [100% clean electricity by 2045](#); Idaho has no state Renewable Portfolio Standard (RPS) or other clean energy target. Utah has enacted a voluntary renewable portfolio goal of 20% renewable energy by 2025. As of 2023, 15.5% of electricity generated in the state was renewable, putting the state on a path to meet the goal.

Transmission

PacifiCorp's [Energy Gateway Transmission Plan](#) addresses future transmission requirements necessary to serve PacifiCorp's Network Load customer needs. In total, the Energy Gateway Transmission plan, initiated in May 2007, adds approximately 2,000 miles of new transmission lines. Segments A, B, C, F, G and parts of Segment D have been completed. Segment D.3 Bridger/Anticline to Populus has a planned in-service date of 2034; Segment E Populus to Hemingway is beyond the 10-year planning horizon.

The 500 kV Boardman to Hemingway transmission line was first proposed in 2007 and has faced multiple delays. Now, as a joint project between Idaho Power and PacifiCorp (represented as Segment H in PacifiCorp's Energy Gateway transmission plan), the companies intend to break ground this year, with a planned in-service date of 2027. This ~295-mile 500 kV transmission line provides ~1,000 MW of bidirectional capacity increase between the Northwest and Idaho.

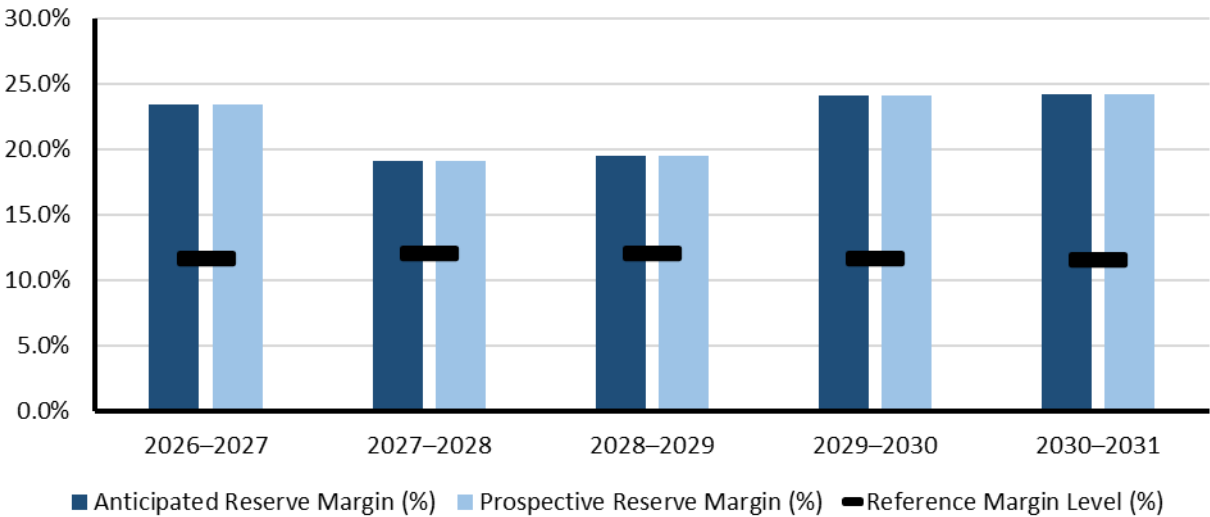


WECC-British Columbia

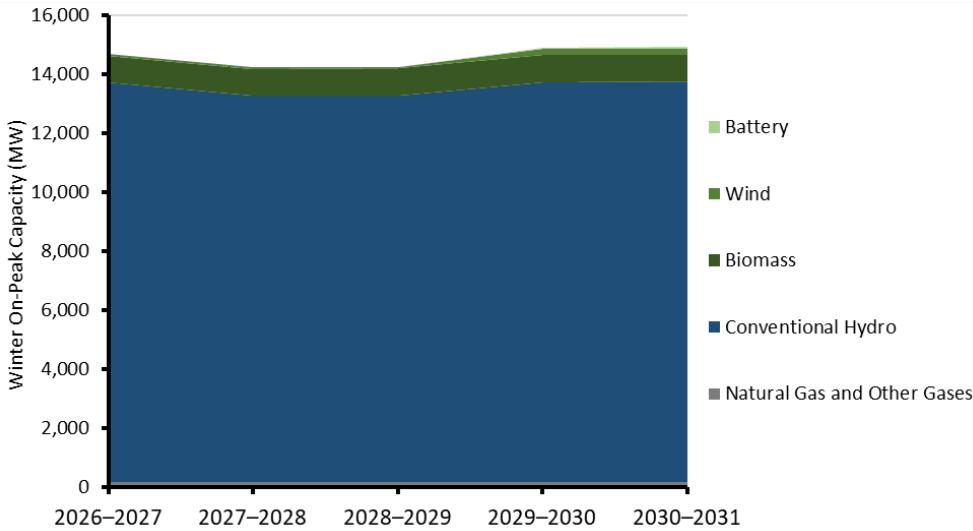
WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and Reliability Coordinator for the 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 Bulk Electric System and its interconnections. BC Hydro operates an integrated system supported by 30 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.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Additions: Tier 1	636	620	625	850	863	863	863	814	863	863
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	381	369	381	381
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	14,072	13,638	13,638	14,072	14,072	14,072	14,072	13,638	14,072	14,072
Anticipated Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Prospective Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Reference Margin Level (%)	11.7%	12.1%	12.1%	11.6%	11.6%	11.6%	11.5%	11.9%	11.5%	11.4%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-British Columbia Highlights

- WECC-British Columbia’s anticipated reserve margin does not fall below the RML during the 2025–2035 timeframe.
- British Columbia’s annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period.
- British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Hydro variability is the biggest operational issue related to generation in WECC-British Columbia.
- BC Hydro’s most recent 10-year capital plan allocates \$36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	170	170	170	170	170
Biomass	900	903	903	900	900
Wind	73	59	59	222	222
Conventional Hydro	13,544	13,104	13,109	13,560	13,573
Other	22	22	22	22	22
Battery	0	0	0	49	49
Total MW	14,708	14,258	14,263	14,922	14,935

WECC-British Columbia Assessment

Planning Reserve Margins

BC Hydro has used the one-day-in-10-years LOLE standard since 1975. Using a probabilistic model, BC Hydro concluded in its updated 2021 IRP that a 12% PRM of dependable generating capacity was required to ensure system resource adequacy. WECC-British Columbia’s ARM does not fall below the RML during the 2025–2035 time frame.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Clean Electricity Regulations were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Provincial policies in BC that might affect resource planning and procurement include the Renewable Energy Projects Act (May 2025), (which streamlines permitting and grants the BC Energy Regulator broader approval powers for wind, solar, and transmission projects) and the BC Clean Power Action Plan (which aims to double clean electricity supply by 2050 and includes a new biennial procurement cycle for renewable resources).

BC Hydro is included in the Powerex footprint in WRAP. The WRAP defines an adequate reserve margin for its footprint for an 18-month forward period based on a loss of load expectation reliability threshold of one event day in 10 years. WRAP uses an ELCC methodology to determine capacity contribution in its analysis. The WRAP is a non-binding program for Winter 2025–26 but is currently planned to transition to a fully binding program with deficiency charges sometime in 2027. For [2025–2026 Winter](#), monthly PRMs for the Northwest WRAP subregion (called Mid-Columbia) range between 11.7% and 27.2%. For [2026 Summer](#), a PRM range between 14.2% and 22.3% is reported.

Energy Assessment, including non-peak hour risk

ProbA Results

British Columbia does not show any LOLH or EUE in 2027 or 2029.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

British Columbia did not have LOLH in 2027 or 2029; therefore, no additional reporting or visualizations are provided.

Demand

British Columbia’s annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period. The primary driver for demand growth in British Columbia is natural gas processing. Significant, but uncertain, effects on demand are also expected because of commercial and residential electrification and simultaneous advances in EE in those two sectors.

Distributed Energy Resources

BC Hydro has a net metering program. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

With its abundant hydro, British Columbia is already approximately 95% carbon free. The [CleanBC Roadmap](#) states, “By 2030, BC will phase out BC Hydro’s last gas-powered facility so the electricity we make is 100% clean.”

British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Tier 3 additions include 500 MW of conventional hydro.

Hydro variability is the main operational and planning issue related to generation in WECC-British Columbia. Over 80% of British Columbia’s capacity is comprised of hydro resources, making hydro variability a concern year-round. While parts of British Columbia remain in drought classification as of the end of October 2025, many of the province’s basins have recovered and conditions are now better for this time of year than in the prior two years. Drought indices for 2026–2027 remain dependent on this year’s snowpack accumulation and subsequent seasonal rain. At this time, it is too soon to forecast whether drought conditions will persist or continue easing into next season for the BC Hydro integrated system. Power imports from the United States to British Columbia assist in maintaining water storage levels. More than a fifth of the power in the province was imported from the United States in 2024. Increasing electrification trends coupled with potential continued drought conditions may exacerbate the need for imports to the region in the future.

As BC is working to phase out its last natural-gas-fired power generation units over the next five years, electric-gas coordination issues are not anticipated for power supply. However, BC’s natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to each other when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

Energy Storage

BC Hydro is expected to add 50 MW of Tier 1 battery energy storage over the next 10 years. Battery storage in the West is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

Energy Transfers

According to NERC’s [*ITCS Canadian Analysis*](#), the total simultaneous transfer capability into the British Columbia transmission planning regions from all its neighbors is 2,897 MW in 2024 Summer and 3,078 MW in 2024/25 Winter. These values translate to approximately 31% of peak summer load and 27% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta).

Transmission

BC Hydro’s most recent 10-Year Capital Plan allocates \$36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets. These changes are expected to shorten development lead-times, boost renewable energy procurement, and enhance grid infrastructure planning.

Reliability Issues

Congestion of the transmission systems supplying high-growth areas of the Lower Mainland and Vancouver Island could be a potential future emerging reliability issue. Load growth due to electrification, expected population increases, and industrial expansion could couple with increased variability in load caused by extreme weather, wildfires, atmospheric rivers, and heat waves or cold snaps, to add stress to the transmission network. Lastly, aging infrastructure could add to higher forced outage risk if supply chain disruptions create project delays, as has been occurring across the Western Interconnection in recent years.

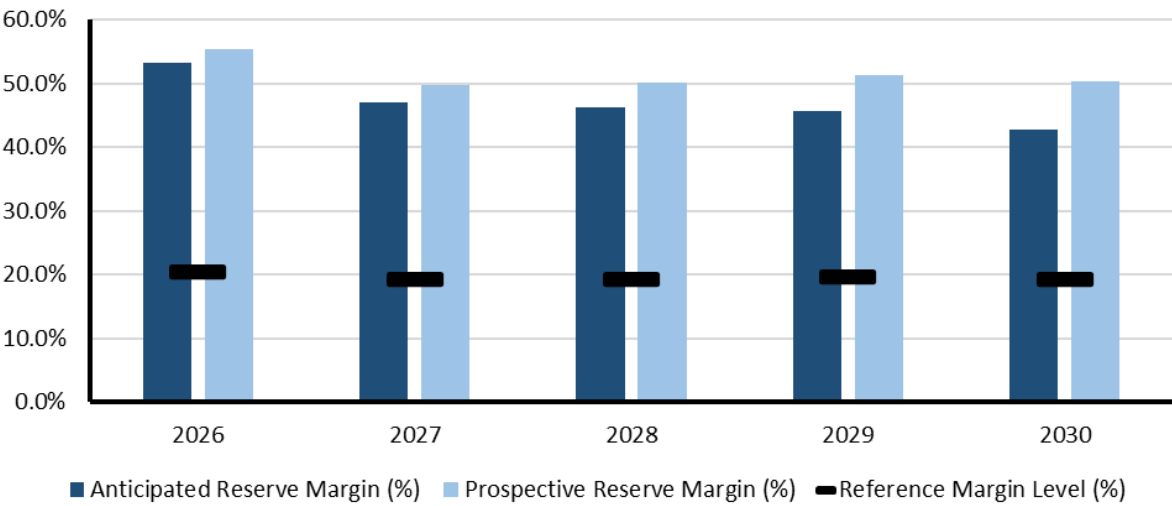


WECC-California

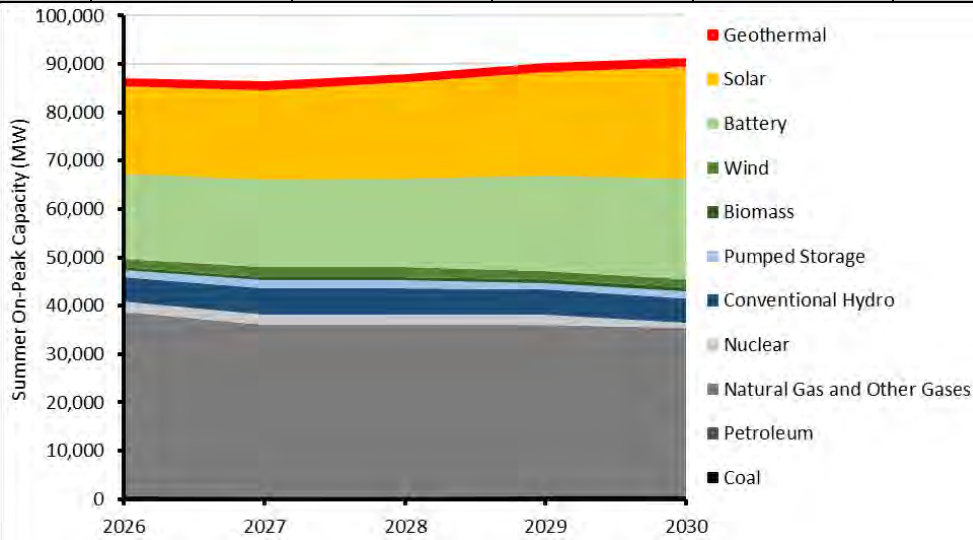
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock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

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	58,165	60,060	61,547	63,261	65,221	66,879	68,315	69,759	71,373	73,017
Demand Response	756	764	775	783	795	799	812	823	836	836
Net Internal Demand	57,409	59,296	60,772	62,478	64,426	66,079	67,504	68,936	70,537	72,182
Additions: Tier 1	11,558	13,202	14,765	17,206	19,945	19,945	21,532	22,541	23,771	25,622
Additions: Tier 2	1,288	1,552	2,388	3,489	4,974	4,974	6,509	8,475	9,208	9,244
Additions: Tier 3	10	10	10	10	557	557	557	562	557	557
Net Capacity Transfers (WECC Model)	561	583	651	639	541	234	310	314	298	287
Existing-Certain and Net Transfers	76,371	73,982	74,050	73,773	71,969	70,585	70,661	70,925	70,649	70,613
Anticipated Reserve Margin (%)	53.2%	47.0%	46.1%	45.6%	42.7%	37.0%	36.6%	35.6%	33.9%	33.3%
Prospective Reserve Margin (%)	55.4%	49.6%	50.1%	51.2%	50.4%	44.5%	46.2%	47.9%	46.9%	46.1%
Reference Margin Level (%)	20.3%	19.2%	19.3%	19.7%	19.3%	19.1%	18.9%	17.8%	18.3%	18.0%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-California Highlights

- The ARM does not fall below the RML. Further, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The California Public Utilities Commission (CPUC) recently increased the PRM requirement for 2026 and 2027 from 17% to 18%. [CPUC’s ruling](#) also maintains procurement targets that provide additional summer reliability resources by ordering IOUs to procure resources of 1,260 to 2,300 MW for the months of June through October in 2026 and 2027.

WECC-California Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	466	466	466	466	466
Coal*	16	16	16	16	16
Petroleum	103	103	103	103	103
Natural Gas	38,144	35,507	35,507	35,468	34,837
Natural Gas*	38,144	34,994	34,994	35,468	34,837
Biomass	734	745	749	749	749
Solar	18,126	18,574	19,936	21,506	23,065
Wind	1,643	1,991	2,000	1,650	1,650
Geothermal	1,809	1,808	1,808	1,809	1,809
Conventional Hydro	5,112	5,426	5,426	5,112	5,112
Pumped Storage	1,401	1,549	1,549	1,401	1,401
Nuclear	2,152	2,151	2,151	2,152	1,076
Other	194	194	194	194	194
Battery	17,486	18,088	18,275	19,731	20,911
Total MW	87,368	86,601	88,164	90,340	91,372
Total MW*	86,918	85,637	87,200	89,890	90,922
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-California Assessment

Planning Reserve Margins

The ARM does not fall below the RML. The California Public Utilities Commission (PUC) recently released a PRM increase for 2026 and 2027 from 17% to 18%. The ruling also increases the PRM procurement target from 1,260 to 2,300 MW for the months of June through October for 2026 and 2027 (divided across the IOUs). Note, the CPUC’s reserve margins are not used in WECC’s methodology for the LTRA.

Energy Assessment, including non-peak hour risk

WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC’s internally developed modeling tool that performs energy based probabilistic assessments that support NERC’s LTRA and seasonal assessments, as well as WECC’s WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

For 2027 and 2029, the peak hour is projected to occur in early September at hour beginning 16:00. California does not show any LOLH or EUE in either 2027 or 2029. No risk period visualizations are included for this subregion as there were no identified risk hours.

Demand

Average annual demand growth rate for WECC-CA is 2.4%. The primary drivers are transportation electrification and incremental load for extreme heat events. Large-load additions in the forecast are 4,993 MW through 2035.

Demand-Side Management

DR accounted for about 2.6% (1,400 MW) of total system resource adequacy capacity in the summer of 2024 compared to about 3 to 4% in the previous four summers. This drop is mainly due to a change in CPUC rules removing the PRM and transmission adders totaling over 11% previously applied to DR capacity.

DR was supplied by CPUC-regulated utility programs, non-utility third-party programs, and non-CPUC jurisdictional load-serving entities (municipal utilities, etc.). Utility DR accounts for about 76% of DR used to meet resource adequacy requirements. About 85% of this capacity was bid into the real-time market during the most critical hours of summer 2024. When dispatched, this category reported curtailing about 81% of scheduled load reductions.

Non-utility (third party) DR accounts for about 18% of DR used as resource adequacy capacity requirements, with actual load reductions of about 54% of scheduled. However, during some hours, this sector exceeded the scheduled level.

Non-CPUC jurisdictional load serving entities (municipal utilities, etc.) utilize an average of about 75 MW of DR—or about 6% of DR used to meet total ISO system resource adequacy requirements. Since this capacity is not bid or scheduled into the ISO market, its performance cannot be verified.

Distributed Energy Resources

A recent policy change in California significantly increased the payback period for residential BTM PV. As predicted, installations of residential rooftop solar systems have fallen to near three-year lows over the past year; existing systems were grandfathered in. Now, the California legislature is considering a bill to undo that grandfathering by reducing those existing net metering contracts with IOUs from 20 years to 10. AB 942 would impact the value of solar on the nearly 2 million homes that have installed panels years ago by shifting them to the “net billing tariff” that pays approximately 75% lower rates for energy sent back to the grid. Given California’s shifting policy environment, it is difficult to predict future adoption of BTM PV solar.

Generation

- **Aging Thermal Resource Fleet:** During the summer, aging thermal resources can become a concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. In addition, thermal plant and system operators are becoming increasingly hard to replace, as there appears to be difficulty in finding personnel with the necessary experience to fill these rolls. Succession planning is becoming an integral part of successful thermal plant operation.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round. BTM resource generation can be masked from the transmission operator and BA. For example, localized cloud coverage limiting BTM output has been seen to increase demand by 200 MW, requiring unplanned additional resources to be dispatched.

Flexible operating reserves remain on standby to address the uncertainty associated with BTM output.

- **BESS Fires:** BESS fires have occurred in California. These are isolated events that can render a BESS inoperable. Electrical faults, manufacturing defects, degradation due to aging, and gas buildup can all lead to fires. New technologies for passive fire suppression, such as immersion cooling, are being developed to reduce the occurrence of BESS fires.
- **Gas Fleet Derates:** Gas resources in this subregion can be derated during extremely hot weather in the summer due to ambient conditions. Quantifying gas fleet limitations and ensuring there are alternative resources available to meet demand is paramount.
- **Hydro Variability:** Primarily during the summer season, variations in annual precipitation can have a significant impact on water supply. Extended droughts can reduce head pressure, directly resulting in the reduction of hydro capacity. Improvements in hydro models for run off and precipitation are in progress to address these concerns. For resource adequacy models, a 1-in-5 dry-year planning scenario is used.
- **Inertia Decline on System:** Local and federal regulations have driven a reduction in traditional spinning mass generators, which has exacerbated frequency deviations in California. Operating plans are being updated with the necessary steps to mitigate this issue. This issue is observed year round.
- **Solar Variability:** Solar output variability is a concern year round. Spring, fall, and winter often have overcast cloud coverage in California, which can make solar output difficult to forecast. Summer evenings tend to be a time of day when demand is elevated but solar output declines. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.
- **Wind Variability:** Wind variability is an operational concern year round. Toward the end of summer, the beginning of winter, and the beginning of spring, Santa Ana Winds can create overspeed conditions for wind turbines, limiting their output. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.

Electric-Gas Coordination

Most entities in California consider electric-gas coordination in long-term planning studies. Resource Planners collaborate with gas supply teams to gather assumptions on forecasted gas deliveries and pricing. Constraints are not directly incorporated in resource planning studies.

Operating Procedure 4120 ensures that CAISO provides daily estimated gas usage reports to gas transmission operators (GTO). These are used as the basis for gas curtailment event planning. This procedure helps mitigate risks associated with gas supply limitations that may impact generation resources and applies to both real-time and day-ahead operations. In addition, participants of RC West have formed the Real-Time Working Group (RTWG). This group convenes prior to extreme weather events to prepare for potential gas supply interruptions. California entities that are part of RC West also participate in the Northwest Mutual Assistance Agreement (NWMMA). Communication protocols include following NERC Reliability Standard COM-002-4 which contains predefined communication procedures. In addition, plant operators work directly with power supply and gas schedulers to coordinate scheduling and dispatch of gas generating resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

California has a mandate for its electricity supply to be 60% carbon free by 2030 and is currently on track to meet that level. The requirement for 100% carbon free is set at 2045.

Transmission

The ITCS report showed that in a heat wave Northern California may be energy-deficient.

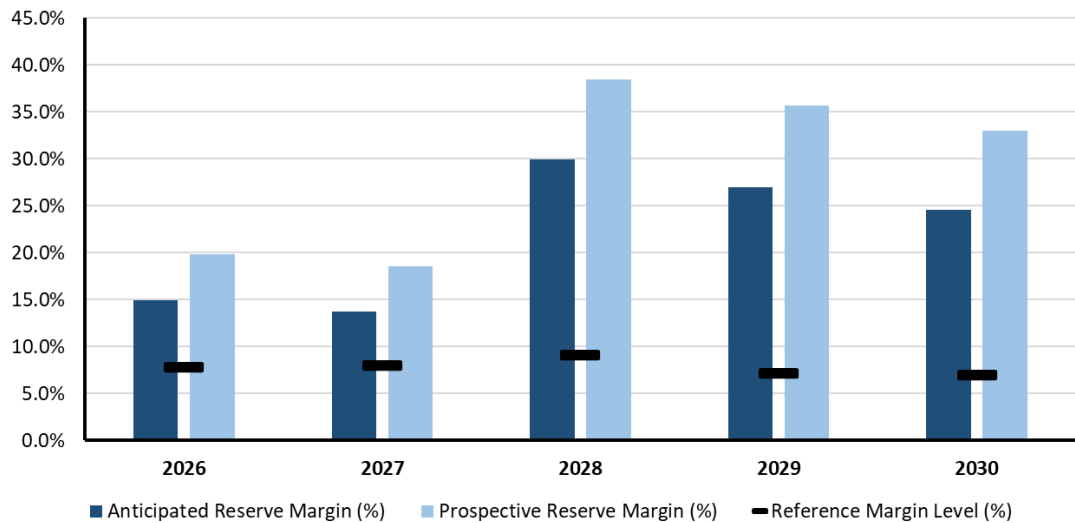


WECC-Mexico

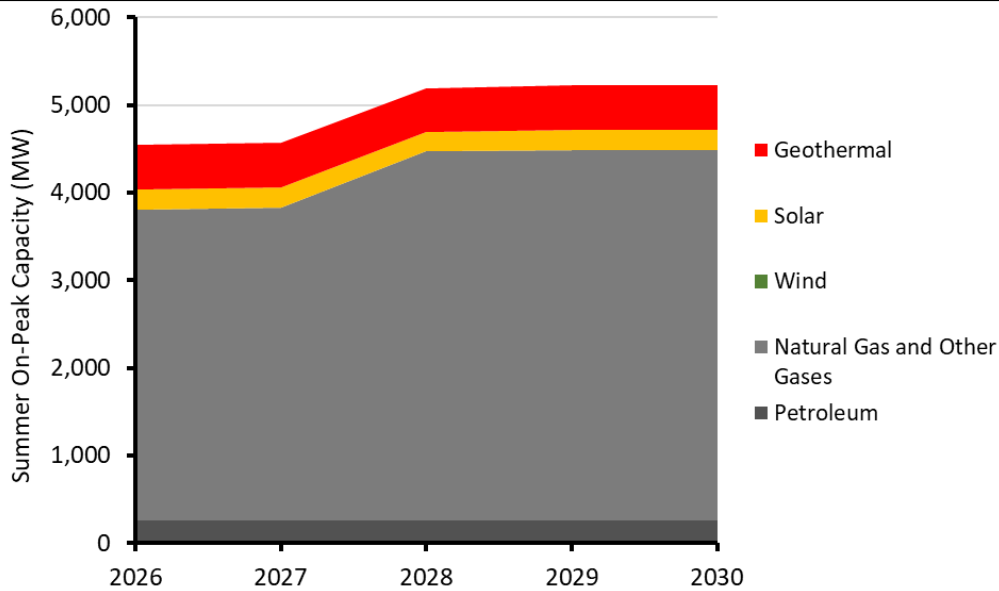
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting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

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Additions: Tier 1	717	722	1,396	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Additions: Tier 2	196	198	367	392	392	392	392	367	392	392
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Capacity Transfers (WECC Model)	0	131	410	482	600	600	600	600	600	600
Existing-Certain and Net Transfers	3,825	3,982	4,209	4,307	4,425	4,425	4,425	4,409	4,425	4,425
Anticipated Reserve Margin (%)	14.9%	13.8%	29.9%	27.0%	24.6%	20.0%	15.7%	11.4%	8.0%	4.5%
Prospective Reserve Margin (%)	19.9%	18.6%	38.4%	35.7%	33.0%	28.1%	23.5%	18.4%	15.2%	11.5%
Reference Margin Level (%)	7.8%	8.0%	9.1%	7.2%	7.0%	6.8%	6.7%	7.4%	6.4%	6.3%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Mexico Highlights

- Centro Nacional de Control de Energía (CENACE) is adding three natural-gas-fired combustion turbine generators (totaling 780 MW in summer capacity) by Summer 2026, increasing planned reserves to above RMLs. An additional 740 MW of natural-gas-fired capacity is in development between 2026 and 2027.

WECC-Mexico Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	0	0	0	0	0
Petroleum	259	261	258	259	259
Natural Gas	3,540	3,566	4,212	4,224	4,224
Biomass	0	0	0	0	0
Solar	229	231	214	229	229
Wind	7	5	6	7	7
Geothermal	506	510	505	506	506
Conventional Hydro	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	0	0	0	0	0
Battery	0	0	0	0	0
Total MW	4,542	4,573	5,195	5,225	5,225

WECC-Mexico Assessment

Planning Reserve Margins

The ARM is above the RML until 2035, the last year of the assessment period.

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

WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC’s internally developed modeling tool that performs energy based probabilistic assessments that support NERC’s LTRA and seasonal assessments, as well as WECC’s WARA.

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

Demand

Average annual demand growth rate for WECC-Mexico is 4.3%. Large-load additions in the forecast are 161 MW through 2035.

Generation

Operational and planning issues related to generation in WECC-Mexico include the following:

- Unplanned Outages of Thermal Sites: High loading on Path 45 (See: [WECC Path Rating Catalog](#)) coupled with outages or derates to large thermal assets in this assessment area can result in the declaration of an EAA and a request for assistance from RC West. This risk is amplified in the summer when demand is highest.
- Electric-Gas Coordination: Electric-gas coordination is considered in long-term planning studies for the WECC-Mexico area. Current and future gas projects and constraints that could compromise supply to generators are incorporated in planning studies. Constant gas supply monitoring is conducted to ensure generating assets remain reliable throughout the year. Multiple suppliers are also available to generators in WECC-Mexico. This allows for supply redundancy if one supplier is experiencing limitations. Communication between gas suppliers and system operators includes the sharing of gas infrastructure maintenance information and consumption forecasts which are provided on a weekly, monthly, and annual cadence.

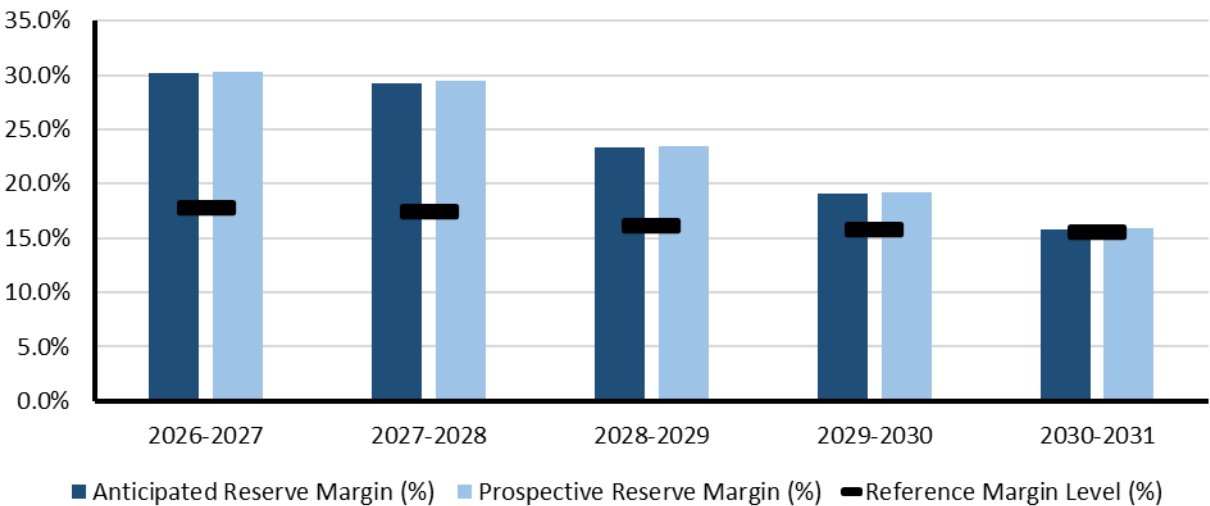


WECC-Northwest

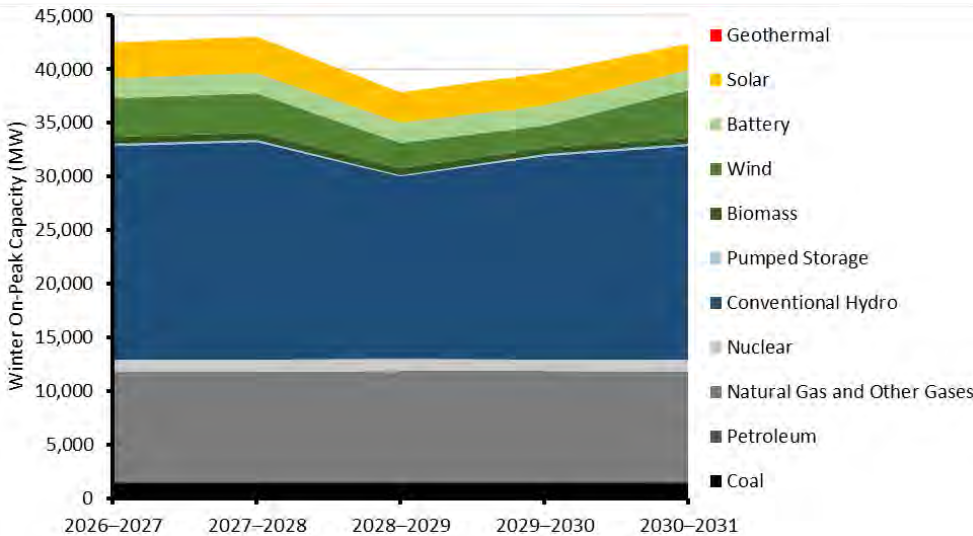
WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for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

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	34,426	34,930	36,038	37,017	37,939	38,821	39,455	40,083	40,563	41,064
Demand Response	30	30	30	30	30	30	30	30	30	30
Net Internal Demand	34,396	34,900	36,008	36,987	37,909	38,791	39,425	40,053	40,533	41,034
Additions: Tier 1	3,463	3,463	3,219	3,219	3,219	3,219	3,463	3,232	3,221	3,217
Additions: Tier 2	10	49	56	56	56	56	49	56	56	56
Additions: Tier 3	697	830	939	4,958	5,389	5,605	6,267	5,963	5,921	5,903
Net Capacity Transfers (WECC Model)	7,242	7,630	7,316	7,066	6,896	6,825	6,825	6,825	6,630	5,841
Existing-Certain and Net Transfers	41,332	41,653	41,169	40,828	40,652	40,564	40,724	40,558	40,360	39,573
Anticipated Reserve Margin (%)	30.2%	29.3%	23.3%	19.1%	15.7%	12.9%	12.1%	9.3%	7.5%	4.3%
Prospective Reserve Margin (%)	30.3%	29.4%	23.4%	19.2%	15.9%	13.0%	12.2%	9.5%	7.7%	4.4%
Reference Margin Level (%)	17.8%	17.4%	16.1%	15.8%	15.5%	15.3%	15.9%	15.0%	14.9%	14.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Northwest Highlights

- The ARM falls below the RML starting in Winter 2031–2032. The assessment area would need additional resources to meet resource adequacy criteria. More details on members participating in the WRAP can be found on the [WRAP Area Map](#).
- For 2027 and 2029, the peak hour is projected to occur in January at hour beginning 10:00.
- Resource adequacy risk is not significant in the Northwest for 2027.
- In 2029, the Northwest subregion shows 8,080 MWh of EUE, with approximately 85% of that occurring between hours beginning 14:00–19:00 in August. Though the magnitude of EUE is greatest in the summer months, LOLH occurs at a greater frequency in the winter months, particularly in January.
- The majority of EUE occurs during the summer from hours beginning 17:00–19:00, during which period demand is elevated but solar output is dissipating.

WECC-Northwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Coal	1,516	1,516	1,475	1,475	1,475
Petroleum	97	97	95	95	95
Natural Gas	10,539	10,533	10,480	10,480	10,480
Biomass	657	617	615	536	536
Solar	1,545	1,544	1,622	1,622	1,622
Wind	2,149	2,149	1,319	1,311	1,311
Geothermal	4	4	4	4	4
Conventional Hydro	17,855	17,835	18,279	18,275	18,270
Pumped Storage	146	146	149	149	149
Nuclear	1,112	1,112	1,108	1,108	1,108
Battery	1,934	1,934	1,927	1,927	1,927
Total MW	37,553	37,486	37,072	36,981	36,976

WECC-Northwest Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Winter 2031–2032. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging.

Non-Peak Hour Risk and Energy Assurance

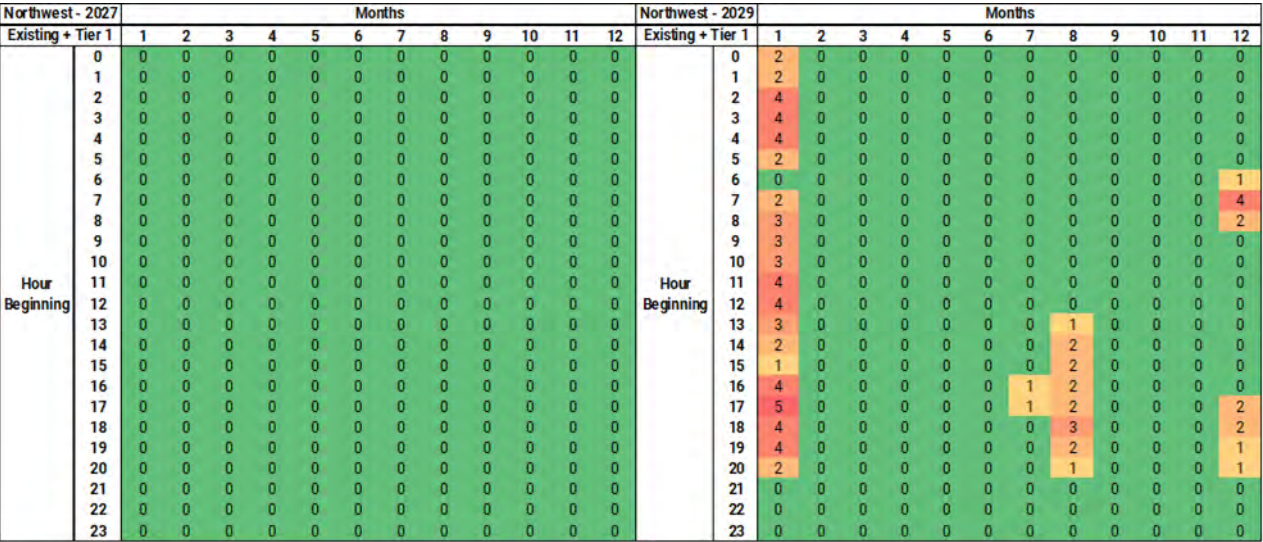
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC’s internally developed modeling tool that performs energy based probabilistic assessments that support NERC’s LTRA and seasonal assessments, as well as WECC’s WARA.

ProbA Results

While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs over the assessment period, unserved energy and load-loss hours increase in the ProbA results.

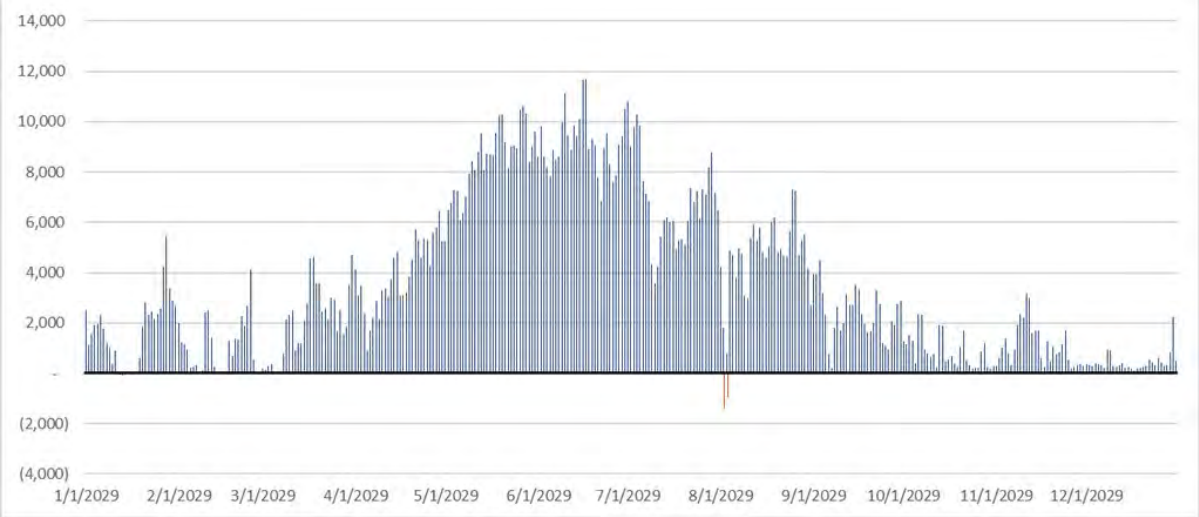
Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	8,080
NEUE (ppm)	N/A	0	36.64
LOLH (hours per Year)	N/A	0	85.00
* No prior results as the assessment area is new for the 2025 LTRA.			

Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results illustrated in the following heat map figure, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year.



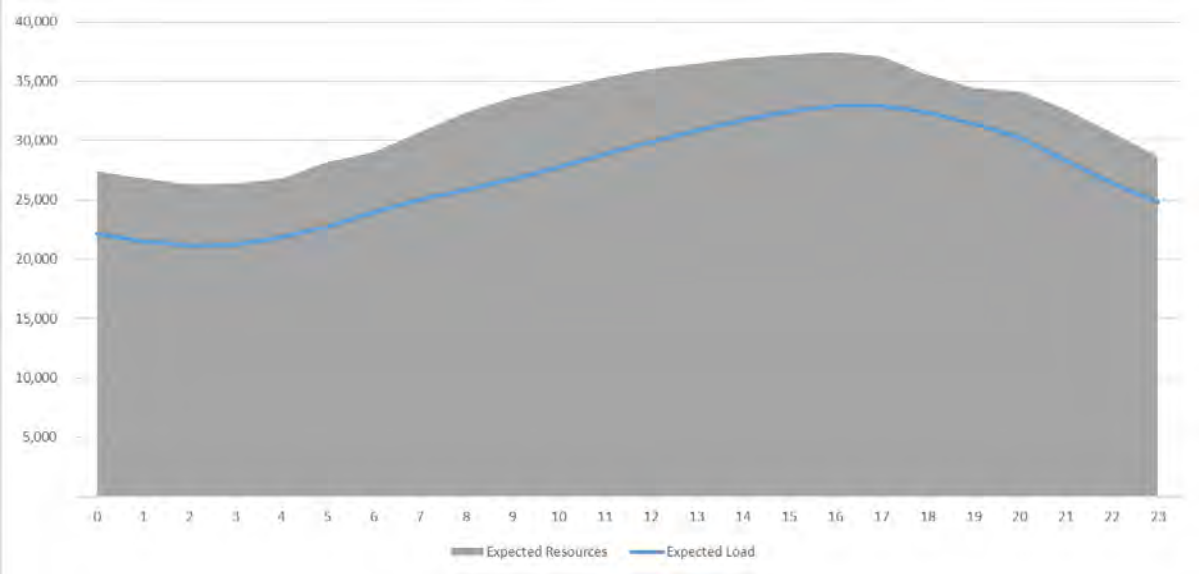
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Northwest Assessment Area in 2027 and 2029

In WECC’s ProbA modeling, energy transfers from neighboring areas are helping WECC-Northwest meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Northwest has excess energy that can be transferred to neighboring areas. Winter months are when WECC-Northwest’s excess energy is at its lowest, and at times in the 2029 study year internal resources are not sufficient for demand. In summer months, WECC-Northwest is projected to have its highest amount of excess energy, though these supplies can still be insufficient for modeled demand during extreme heat events. Such occurrences can cause deficits represented in the figure below, and energy can go unserved when neighboring areas do not have surplus energy to transfer.



Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. For the Northwest, this occurs in mid-to-late summer. LOLH occurs from hours beginning 14:00 through 19:00. The majority of EUE during these hours occurs from hours beginning 17:00–19:00, during which period demand remains elevated whereas solar output dissipates. There is no LOLH in 2027. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Northwest assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.



Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year

Demand

Average annual demand growth rate for WECC-Northwest is 2.7%. The primary drivers are data centers, residential electrification, residential customer growth, transportation electrification, and semiconductor manufacturing. Large-load additions in the forecast are 7,652 MW through 2035.

Distributed Energy Resources

In the Northwest, Oregon IOUs continue to offer net metering with carryover credits within a calendar year and annual excess credits going to low-income programs. However, the state’s largest IOU has proposed a change that largely mirrors California’s revised lower credits; if adopted, this would slow the rate of installations in Oregon as well (where the latitude and climate already lengthen the customer’s payback period relative to California).

In Washington, utilities have the option to propose a BTM PV credit that is less than the retail rate once they reach a threshold of 4% of their 1996 peak load. The current program is in effect until at least 2029. However, given the progress toward the 4% penetration rate (below), that year may trigger a slowdown in new installations of BTM PV.

Generation

Operational and planning issues related to generation in WECC-Northwest include the following:

- **Aging Thermal Resource Fleet:** A year-round concern for this subregion is an aging thermal resource fleet. Older resources require additional maintenance and can be prone to forced outages or partial derates. Necessary maintenance and capital expenditures are made to ensure these generators provide reasonable performance when called upon. Planned maintenance outages for these resources may be done at a higher frequency during the shoulder months to avoid unplanned outages during the summer months. However, major upgrades to aging infrastructure reduce system capability for extended periods of time, increasing reliance on imports. Supply chain delays and staffing issues can cause planned outages to extend well beyond their anticipated end date. Staffing shortages have been noted by multiple entities in the Northwest.
- **Hydro Variability:** The Northwest has a large share of hydro resources in its portfolio making hydro generating capability a concern year-round. Seasonal hydro variability and below average inflows observed by some entities in this region from April through November of last year resulted in projects being ran at minimum flow. Underperforming hydro resources can result in entities relying heavily on imports to meet peak load hours. During extreme cold conditions, run of river hydro sites can also be derated due to icing. Performing maintenance during shoulder seasons can help keep hydro on-line during the winter and summer seasons. Improving hydro forecasting for short- and long-term planning models can assist system dispatchers with daily operating plans and resource planners in completing accurate resource adequacy studies.
- **Solar Variability:** Solar output variability due to cloud coverage can be a minor concern year-round in this subregion. Entities in this subregion state there are sufficient flexible resources in their portfolio to address solar output uncertainty.
- **Wind Variability:** Wind variability is of particular concern for this subregion during the winter. Cold weather mixed with moisture can cause icing conditions on wind turbine blades, which can severely derate a wind site. Entities in this subregion state that there are sufficient flexible resources in their portfolio to address wind output uncertainty in the winter.
- **Electric-Gas Coordination:** The Northwest subregion contains entities that consider electric-gas coordination in long-term planning studies, as well as entities that do not. Several gas supply options for future generating assets are evaluated to ensure alternatives exist if one supply point is curtailed. Price certainty from suppliers is also a major consideration in

planning studies. Annual natural-gas-load studies are conducted to help identify parts of the gas distribution system that may experience low pressure during peak cold conditions. These areas of the gas system are identified, and recommendations to address this issue are prioritized and completed. If an issue cannot be addressed within a short period of time, contingency plans are developed for these areas during high gas demand or peak cold conditions. Entities in the Northwest subregion are participants in the NWMMA mentioned earlier in the Basin subregion. Status reports and planned resource output forecasts are communicated between electric and gas teams daily to ensure operational needs are met.

- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Washington is required to have zero coal generation by 2025, be greenhouse gas neutral by 2030 (can use offsets), and be 100% non-emitting by 2045 without using offsets. Oregon passed a requirement for its investor-owned utilities to be 80% below their 2005 emissions baseline by 2030, 90% below by 2035, and 100% below (zero emissions) by 2040. Montana has a 15% renewables target that has been met, with no incremental increases in the out-years.

Transmission: PacifiCorp’s [Blueprint transmission project](#) will connect major resource and load areas in central and eastern Oregon through construction of approximately 320 miles of new 500 kV transmission line and associated 500 kV and 230 kV system upgrades, in three primary segments planned to be fully in-service in 2028 and 2032. The Blueprint project will largely parallel the existing Northwest AC Intertie 500 kV system, interconnecting at various points and requiring significant coordination with ac Intertie owners and other affected systems. Affected paths include WECC Paths 14, 66 and 75.

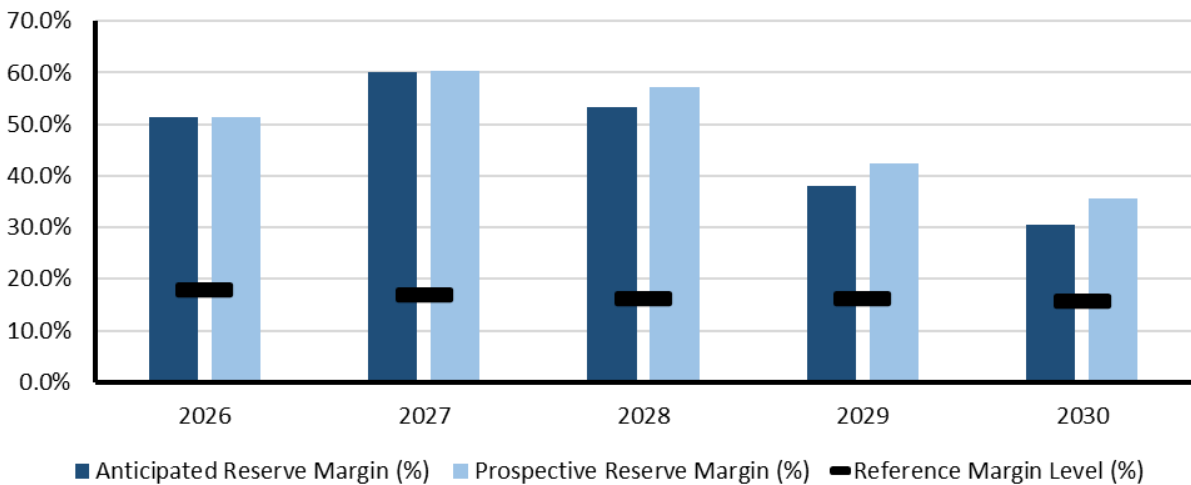


WECC-Rocky Mountain

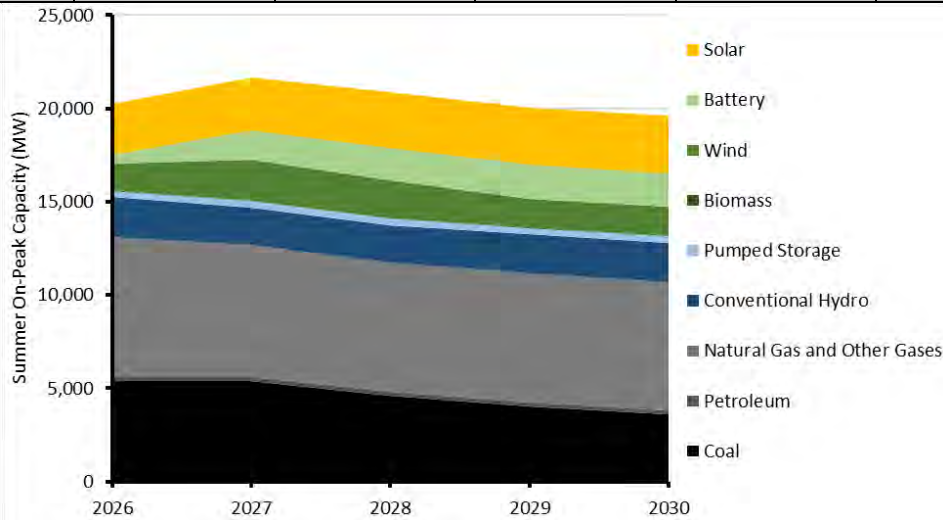
WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and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

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	14,004	14,338	14,565	15,021	15,442	15,873	16,306	16,764	17,207	17,297
Demand Response	287	290	293	285	287	290	293	296	298	301
Net Internal Demand	13,717	14,048	14,272	14,736	15,154	15,583	16,013	16,468	16,909	16,997
Additions: Tier 1	1,771	3,486	3,979	4,079	4,079	4,079	4,355	4,299	4,079	4,079
Additions: Tier 2	0	45	585	640	761	761	810	810	761	761
Additions: Tier 3	17	178	925	1,160	1,373	3,207	3,276	4,188	4,274	4,370
Net Capacity Transfers (WECC Model)	391	661	852	179	50	23	0	0	0	0
Existing-Certain and Net Transfers	18,979	18,995	17,884	16,278	15,696	14,882	14,721	14,329	14,143	14,098
Anticipated Reserve Margin (%)	51.3%	60.0%	53.2%	38.1%	30.5%	21.7%	19.1%	13.1%	7.8%	6.9%
Prospective Reserve Margin (%)	51.3%	60.3%	57.3%	42.5%	35.5%	26.6%	24.2%	18.0%	12.3%	11.4%
Reference Margin Level (%)	17.8%	17.0%	16.2%	16.1%	15.7%	15.2%	13.5%	11.9%	14.1%	13.9%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Rocky Mountain Highlights

- ARM remains above the RML through 2033. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period.

WECC-Rocky Mountain Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	5,383	5,376	4,623	4,034	3,585
Coal*	5,053	5,376	4,429	3,379	2,180
Petroleum	204	204	204	204	204
Natural Gas	7,522	7,083	6,897	6,902	6,902
Biomass	6	6	6	3	3
Solar	2,695	2,873	3,002	3,071	3,071
Wind	1,437	2,218	2,054	1,555	1,550
Conventional Hydro	2,139	2,043	2,029	2,116	2,116
Pumped Storage	346	340	340	346	346
Other	126	126	126	126	126
Battery	496	1,547	1,726	1,817	1,817
Unknown	6	5	5	6	6
Total MW	20,359	21,820	21,011	20,178	19,725
Total MW*	20,029	21,820	20,817	19,523	18,320
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-Rocky Mountain

Planning Reserve Margins

The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period. In Winter 2033–34, the ARM falls below the RML, but the prospective resources are expected to sufficiently cover a shortfall. No BAs in this region are WRAP participants.

The Public Service Company of Colorado (PSCo), a subsidiary of Xcel Energy, has used a 16.3% long-term PRM requirement in its Electric Resource Plan (2021), based on a loss of load probability of 1-day every 10 years. PSCo’s reserve margin is not used in WECC’s methodology for the LTRA.

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

WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC’s internally developed modeling tool that performs energy based probabilistic assessments that support NERC’s LTRA and seasonal assessments, as well as WECC’s WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
*No prior results as the assessment area is new for the 2025 LTRA.			

Since WECC-Rocky Mountain does not show any LOLH or EUE in 2027 or 2029, no additional reporting of results or visualizations are provided.

Demand

Average annual demand growth rate for WECC-Rocky Mountain is 2.5%. The primary drivers are data centers, commercial customer growth, and industrial customer growth. Large-load additions in the forecast are 574 MW through 2035.

Demand-Side Management

PSCo offers a wide array of DR programs. Total summer demand-reduction estimates for controllable programs for can be found in its [Demand Side Management & Beneficial Electrification Plan](#).

Distributed Energy Resources

BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DERs).

Generation

Operational and planning issues related to generation in WECC-Rocky Mountain include the following:

- Unplanned Outage Extensions:** Supply chain issues, unplanned discovery work, and vendor availability have driven unplanned extensions of resource outages in the Rocky Mountain area. Difficulty in boiler feed pump procurement has resulted in at least one generating asset being unavailable for over nine months. Another thermal site was undergoing a rotor swap and piping inspection, which revealed significant weld defects and pipe cracks. This resulted in a two-month outage being extended into the following year. A hydro site has been unavailable for much of 2024 due to a penstock leak which has been unable to be repaired due to vendor unavailability. Alternative vendors are being sought after for hydro repair work, and contracts to expedite the procurement of equipment will be in place going forward to mitigate these issues.
- Solar and Wind Variability:** Smaller entities in the Rocky Mountain area have stated that wind and solar variability is a concern year-round due to a lack of geographic diversity. These entities are pursuing advancement into RTOs to leverage the advantages of a wider footprint and additional resources.
- Electric-Gas Coordination:** The Rocky Mountain area contains entities that consider electric-gas coordination in long-term planning studies as well as entities that do not. For entities that do consider electric-gas coordination, peak capacity requirements for the local distribution company (LDC) and generating assets are inputs into long term planning models. Peak capacity requirements define the pipeline capacity and contractual volumes needed to fulfill LDC and electric needs. In addition, known and historical constraints on pipelines are considered in resource planning studies. Gas suppliers in this subregion have multiple delivery points to resources. This allows for an alternative location for delivery if one delivery point is inaccessible. In addition, gas supply teams provide an email with natural gas price information and constraints to generation dispatchers and marketers daily. During times of cold weather, this communication stream can be expanded to include interstate gas control and commercial operations.

- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Colorado requires investor-owned utilities to adopt plans to reduce greenhouse gas emissions by at least 80% by 2030, using a 2005 baseline. While the state is on track to achieve this, the additional goal of being 100% carbon free by 2040 is being discussed by utilities, regulators, and legislators, with a proposal to extend the out-year to 2050 in light of the upward pressure on the cost of renewables caused by potential repeal of tax credits and higher tariffs on imports.

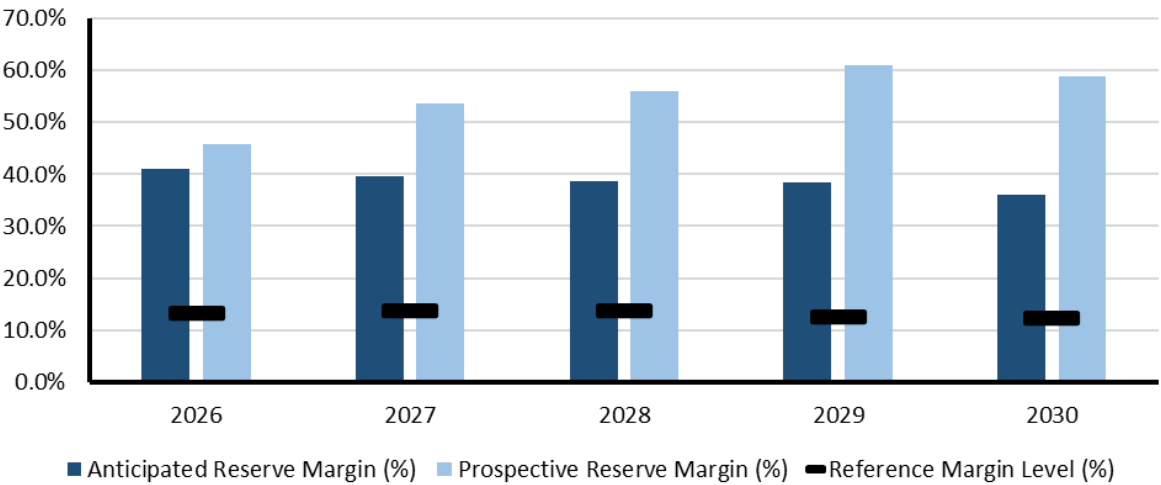


WECC-Southwest

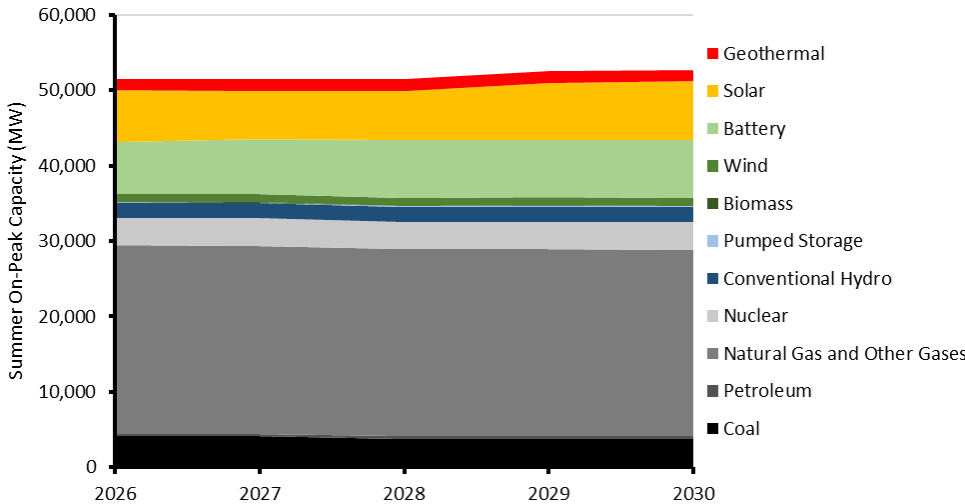
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for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

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	37,407	38,911	40,429	41,887	43,551	44,772	45,664	46,317	47,226	47,988
Demand Response	237	258	264	272	282	237	258	264	272	282
Net Internal Demand	37,169	38,653	40,165	41,615	43,269	44,535	45,405	46,053	46,953	47,706
Additions: Tier 1	6,639	7,501	8,155	8,562	8,914	8,914	8,914	8,396	8,852	8,852
Additions: Tier 2	1,771	5,410	6,994	9,369	9,872	11,263	11,286	10,468	11,286	11,252
Additions: Tier 3	2,502	3,899	5,242	7,562	9,710	12,409	14,804	14,801	24,521	24,571
Net Capacity Transfers (WECC Model)	902	2,544	4,162	5,101	6,301	5,895	5,570	4,880	5,030	4,715
Existing-Certain and Net Transfers	45,794	46,457	47,523	49,023	49,986	49,308	47,432	44,294	44,948	43,944
Anticipated Reserve Margin (%)	41.1%	39.6%	38.6%	38.4%	36.1%	30.7%	24.1%	14.4%	14.6%	10.7%
Prospective Reserve Margin (%)	45.8%	53.6%	56.0%	60.9%	58.9%	56.0%	49.0%	37.1%	38.6%	34.3%
Reference Margin Level (%)	13.3%	13.7%	13.6%	12.6%	12.2%	12.0%	11.7%	12.3%	11.3%	11.1%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Southwest Highlights

- ARM remains above the RML through 2034. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM falls below the RML in Summer 2034. With the addition of Prospective Resources, the area can remain above RML.

WECC-Southwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	4,121	4,116	3,749	3,754	3,754
Coal*	3,761	4,116	3,749	3,754	2,576
Petroleum	341	340	340	336	336
Natural Gas	24,978	24,887	24,817	24,837	24,750
Biomass	46	46	46	46	46
Solar	6,867	6,349	6,503	7,474	7,804
Wind	1,059	1,055	1,055	1,059	1,050
Geothermal	1,555	1,555	1,607	1,572	1,454
Conventional Hydro	1,984	1,989	1,989	1,982	1,981
Pumped Storage	113	113	113	113	113
Nuclear	3,641	3,640	3,640	3,641	3,641
Battery	6,824	7,325	7,657	7,671	7,671
Total MW	51,530	51,414	51,516	52,484	52,598
Total MW*	51,170	51,414	51,516	52,484	51,421
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-Southwest

Planning Reserve Margins

The ARM falls below the RML in Summer 2034 but is covered by the PRM. Arizona Public Service and Public Service Company of New Mexico (PNM) are participants in the WRAP.

Energy Assessment, Including Non-Peak Hour Risk

WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC’s internally developed modeling tool that performs energy based probabilistic assessments that support NERC’s LTRA and seasonal assessments, as well as WECC’s WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

WECC-Southwest does not show any LOLH or EUE in 2027 or 2029; therefore, no additional visualizations are provided.

Demand

The average annual demand growth rate for WECC-Southwest is 3.9%. The primary drivers are data centers, industrial electrification, residential electrification, and residential customer growth. Large-load additions in the forecast are 9,422 MW through 2035.

Demand-Side Management

In the Southwest, Arizona Public Service is in the process of implementing numerous DSM pilots and programs such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. The Residential Energy Storage Pilot enables the company to dispatch a small battery energy storage system up to 20% of the system’s capacity.

Salt River Project (SRP) continues to leverage approximately 87 MW of DR capability through more than 75,000 residential smart thermostats, and 41 MW from over 500 businesses enrolled as interruptible customers. SRP intends to achieve 300 MW of dispatchable DR capability by 2035.

PNM programs reduce peak demand by an average of 45 MW per summer event from its two primary programs enrolling the ability to call on commercial customers and residential air conditioners up to 100 hours with a four-hour limit per curtailment.

Distributed Energy Resources

BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DER).

Generation

Operational and planning issues related to generation in WECC-Southwest include the following:

- **Aging Thermal Resource Fleet:** A year-round concern for this subregion is an aging thermal resource fleet. Hundreds of MW of capacity in this region have been operational for over 60 years. During the winter, certain thermal resources are unable to cycle below 40°F due to freezing issues. Older sites also require extensive overhauls such as generator rewinds that can keep resources out of service for extended periods of time and potentially longer than planned as discovery work manifests into additional maintenance. To reduce the risk of age-related forced outages, plant staff adhere to a strict maintenance schedule with frequent inspections, and unit performance is routinely monitored.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round as BTM solar can supply a large amount of energy to the system. Unanticipated loss of BTM generation is addressed through activation of DR programs, peaking power plants, and maintaining sufficient BESS charge. Near-term forecasts for BTM output are also made available to system operators so they can pre-emptively dispatch the system as needed.
- **Coal Inventory Shortages:** In-progress fuel conversions of coal to gas create a balancing act of maintaining coal on-site to operate resources while also avoiding excess coal post conversion. This can limit coal resources to minimum output prior to the fuel conversion outage. In addition, site-specific challenges at coal mines have delayed coal deliveries to resources in this subregion. Active management of on-site inventory and procurement of fuel from other sources can mitigate these issues.

- **Gas Fleet Derates:** Gas resources in this subregion can be derated during hot weather in the summer due to ambient conditions. During the winter, gas supply has been cut to plants in this subregion during cold snaps. Near-term monitoring of gas availability along with additional market purchases or fuel switching for capable resources can assist in mitigating supply issues.
- **Solar Variability:** Solar output variability is a concern year-round for this subregion. It is a primary concern on summer evenings as solar output rapidly declines whereas load increases or remains elevated. Activation of DR programs, peaking/flexible power plants, and maintaining sufficient BESS charge are all potential strategies to mitigate this issue. Large changes in solar output can also cause extreme ACE fluctuations, which are addressed using BESS.
- **Electric-Gas Coordination:** Most entities in the area consider electric-gas coordination in long-term planning studies. Resource planning models compare forecasted gas usage on both daily and hourly intervals to firm contractual rights. Gas usage exceeding firm obligations results in unserved energy, which can then be addressed via spot market purchases, short-term gas transport capacity purchases, or the dispatching of other resources. Entities also account for forecasted LDC usage and reduce the available natural gas for electric use by this amount. Resource adequacy models do not yet incorporate gas pipeline constraints, but consideration is being given to how to incorporate these into modeling efforts.

Procedures to mitigate gas supply issues include anticipating losses of scheduled gas from the supply side, ensuring scheduled pipeline maintenance is accounted for in operations, and

maximizing the availability of dual fuel resources. Planning teams also coordinate with operations teams for gas supply issues on a season-ahead basis, and operations can re-dispatch the system as needed to manage fuel shortages. During times of potential freeze-offs, trading practices may also be changed to not overextended firm load requirements. Entities maintain winter and summer readiness plans that are shared between electric system operators and gas pipeline operators to ensure maintenance schedules are aligned. Gas system limitations are made known to electric system operators through routine meetings between system operators and pipeline operators.

- **Renewable Portfolio, Clean Electricity & Emissions Standards:** In the Southwest region, Arizona has an RPS mandate for its electric supply to be 15% renewable by 2025. Separately, [APS](#) has committed to ending the use of coal-fired generation after 2031, and the company set a 100% carbon free by 2050 goal. SRP has goals to reduce CO2 emissions per MWh by 62% from 2005 levels by 2035 and 90% by 2050; TEP will stop using coal by 2032 and plans to reduce carbon emissions by 80% by 2035. New Mexico has set more aggressive mandates, requiring 50% renewable by 2030, 80% by 2040, and 100% by 2045.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load ⁴⁹ for the summer and winter of each year. ⁵⁰ Projected total internal demand is based on normal weather (50/50 distribution) ⁵¹ and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	Peak Season	Coincident / Noncoincident ⁵²	Load Forecasting Entity
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro-Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-Alberta	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-Basin	Summer	Noncoincident	
WECC-British Columbia	Winter	Noncoincident	
WECC-California	Summer	Noncoincident	
WECC-Mexico	Summer	Noncoincident	

⁴⁹ [Glossary of Terms Used in NERC Reliability Standards](#).

⁵⁰ The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).

⁵¹ Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.

⁵² Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	Peak Season	Coincident / Noncoincident ⁵²	Load Forecasting Entity
WECC-Northwest	Winter	Noncoincident	
WECC-Rocky Mountain	Summer	Noncoincident	
WECC-SW	Summer	Noncoincident	
Resource Categories			
NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.			
Anticipated Resources⁵³ - Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct. - Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements - Firm capacity transfers (Imports minus Exports): transfers with firm contracts - Less confirmed retirements⁵⁴			
Prospective Resources: Includes all “anticipated resources” plus the following: - Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons. - Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements - Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation. - Less unconfirmed retirements.⁵⁵			

⁵³ Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

⁵⁴ Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

⁵⁵ Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to “Existing” with capacity contributions entered in “Expected-Other.” Once a “mothballed” unit is confirmed to be capable for commercial operation, capacity contributions should be entered in “Expected-Certain.”
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area’s planning processes):⁵⁶
 - Construction complete (not in commercial operation)
 - Under construction
 - Signed/approved Interconnection Service Agreement (ISA)
 - Signed/approved Power Purchase Agreement (PPA) has been approved
 - Signed/approved Interconnection Construction Service Agreement (CSA)
 - Signed/approved Wholesale Market Participant Agreement (WMPA)
 - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area’s planning processes):⁵⁷
 - Signed/approved Completion of a feasibility study
 - Signed/approved Completion of a system impact study
 - Signed/approved Completion of a facilities study
 - Requested Interconnection Service Agreement
 - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

⁵⁶ AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

⁵⁷ AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

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

Methods and Assumptions

How NERC Defines BPS Reliability

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

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

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

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment⁵⁸
- Voltage reductions (sometimes referred to as “brownouts” because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term “rotating” is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

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

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.⁵⁹ NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),⁶⁰ which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
 - The BES does not experience instability, uncontrolled separation, cascading,⁶¹ and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.⁶²
 - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
 - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.

⁵⁸ Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: [NERC Glossary of Terms](#)

⁵⁹ [BES Definition](#)

⁶⁰ NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.

⁶¹ NERC’s Glossary of Terms defines Cascading: “Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.”

⁶² NERC’s Glossary of Terms defines Disturbance: “1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.”

- Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

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

NERC assesses resource adequacy by evaluating each assessment area’s PRMs relative to its RML—a “target” or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

- **Adequate:** The ARM is greater than RML.
- **Marginal:** The ARM is lower than the RML and the PRM is higher than RML.
- **Inadequate:** The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

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

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system’s hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system’s reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

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

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

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

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.⁶³ This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

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

- **Normal Risk:** Negligible amounts of LOLH and EUE.
- **Periods of Risk:** LOLH < 2 Hours and EUE < 0.002% of total annual net energy.
- **Significant Risk:** LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

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

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

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

Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
 - Planned (any of the following):
 - Permits have been approved to proceed

⁶³ https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

- Design is complete
- Needed in order to meet a regulatory requirement
- **Conceptual** (any of the following):
 - A line projected in the transmission plan
 - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”
 - Other projected lines that do not meet requirements of “Under Construction” or “Planned”

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2026–2030)					
Assessment Area	Reference Margin Level	Assessment Area Terminology	Requirement?	Methodology	Reviewing or Approving Body
MISO	2025-2026 Summer: 8.1% Fall: 14.9% Winter: 19.1% Spring (2027): 26.2%	Planning Reserve Margin	Yes: Established Annually ⁶⁴	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0% ⁶⁵	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	13.0–13.4%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0% ⁶⁶	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	15.8–22.6%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	11.9–12.2%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	18.6–26.3%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0% ⁶⁷	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

⁶⁴ In MISO, the states can override the MISO PRM.

⁶⁵ The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

⁶⁶ The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system’s resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

⁶⁷ SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Reference Margin Levels for Each Assessment Area (2026–2030)					
Assessment Area	Reference Margin Level	Assessment Area Terminology	Requirement?	Methodology	Reviewing or Approving Body
SERC-East	15.0% ⁶⁸	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0% ⁶⁹	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0% ⁷⁰	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustent for non-modeled market considerations	ERCOT Board of Directors
WECC-Alberta	11.6–17.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁷¹
WECC-Basin	12.3–14.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-British Columbia	11.6–12.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-California ⁷²	19.2–20.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-Mexico	7.0–9.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-Northwest	15.5–17.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-Rocky Mountain	15.7–17.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸
WECC-Southwest	12.2–13.7%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC ⁵⁸

⁶⁸ SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

⁶⁹ SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.

⁷⁰ SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

⁷¹ WECC’s RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.

⁷² California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage>.

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC’s LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

LTRA Recommendations and Ongoing ERO Actions

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

- 1. Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.
- 2. Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.⁷³ A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.⁷⁴ Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.⁷⁵ Guided by NERC’s comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.^{76,77}
- 3. Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.⁷⁸ Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.⁷⁹

⁷³ See the ERO’s extensive IBR event reporting here: [NERC Major Event Reports](#)

⁷⁴ The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: [Industry Recommendation: Inverter-Based Resource Performance Issues](#).

⁷⁵ NERC’s comprehensive initiatives to reduce IBR risks are detailed here: [IBR Quick Reference Guide](#)

⁷⁶ [NERC IBR Activities](#)

⁷⁷ [Order No. 901 Work Plan](#)

⁷⁸ [The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report](#)

⁷⁹ [Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott](#)

LTRA Recommendations and Ongoing ERO Actions

4. Mitigate fuel-related risks to electricity generation (fuel assurance): In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, provides planning guidance.⁸⁰

Initiative	Description	Product/Reliability Solution
Cold Weather Reliability Standards and Activities	Cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and BAs for use in operating plans. Additional Reliability Standard requirements were developed by NERC and industry to address further recommendations of the <i>FERC-NERC-Regional Entity Staff Report—The February 2021 Cold Weather Outages in Texas and the South Central United States</i> and respond to FERC directives.⁸¹ In September 2025, FERC approved EOP-012-3 with an effective date of October 1, 2025. The revised standard strengthens generator preparedness by providing clearer and more effective requirements. In the approval order, FERC also directed NERC to make information filings to FERC every two years beginning in October 2026 and continuing through October 2034, to assess the adequacy of the standard’s ability to address reliability concerns and inform potential future modifications.	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter-Based Resources Strategy	NERC’s IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC’s extensive activities in each area are described in detail in the <i>IBR Activities Reference Guide</i>.⁸² NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars

⁸⁰ Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: [NERC Reliability and Security Guidelines](#)

⁸¹ Refer to [Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination](#) and [Project 2024-03 Revisions to EOP-012-2](#) on NERC’s standards development page. [Project 2021-07 IBR Activities](#)

⁸² [IBR Activities](#)

LTRA Recommendations and Ongoing ERO Actions

	FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered BPS-connected IBRs. ⁸³ Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.	
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, <i>Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System</i> , incorporated the <i>Design Basis for Natural Gas Study</i> developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry’s development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page. ⁸⁴	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 1. Develop the transmission network: ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.		
Initiative	Description	Product/Reliability Solution
Interregional Transfer Capability Study (ITCS)	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024 ⁸⁵ . The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis was published in 2025. ⁸⁶ See Interregional Transfer Capability Study (ITCS) Canadian Analysis .	ERO Study and Recommendations

⁸³ [FERC Order Issued November 17, 2022](#)

⁸⁴ [RSTC Approved Documents](#)

⁸⁵ NERC’s [Interregional Transfer Capability Study \(ITCS\) Final Report](#)

⁸⁶ [NERC’s Interregional Transfer Capability Study \(ITCS\) Canadian Analysis Final Report](#)

LTRA Recommendations and Ongoing ERO Actions

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

- 1. Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.
- 2. Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.
- 3. Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources’ variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators.⁸⁷
- 4. Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.
- 5. Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.⁸⁸

⁸⁷ [NERC ERS Measure 6 Forward Tech Brief](#)

⁸⁸ A comprehensive guide to ERO activities on DERs can be found here: [DER Activities](#)

LTRA Recommendations and Ongoing ERO Actions

Initiative	Description	Product/Reliability Solution
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this <i>2025 LTRA</i> to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC’s ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.⁸⁹ The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls. New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 <i>Energy Assurance with Energy Constrained Resources</i>.⁹⁰ In other Reliability Standard development work, Project 2023-07 <i>Transmission System Planning Performance Requirements for Extreme Weather</i> requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.⁹¹	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The statuses of NERC’s extensive activities in each area are described in detail in the <i>DER Activities Reference Guide</i> . ⁹²	Reliability Standards Reliability Guidelines Educational Webinars
Strengthen relationships among reliability stakeholders.		
Initiative	Description	Product/Reliability Solution
Ongoing Strategic Engagements	NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

⁸⁹ [ERAWG](#)

⁹⁰ [Project 2022-03](#)

⁹¹ [Project 2023-07](#)

⁹² [DER Activities](#)

Errata

February 2026

- Resource mix changes: Corrected natural gas, solar, wind, conventional hydro, battery, and total resource capacity for 2025 in Table 16. Corrected the caption of Figure 16 (p. 30).
- WECC British Columbia: Corrected highlights for BC Hydro’s most recent 10-year capital plan (p. 144 and 146), corrected the WRAP participation description (p. 145), corrected the DER programs (p. 145), and included a more current drought outlook from October 2025 in the Generation section (p.145)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-21
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit X: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin,
Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1
(Tri-State, 2023 ERP Phase I, Rev. 2 (Apr. 22, 2024))



Tri-State Generation and Transmission Association, Inc.

2023 Electric Resource Plan

Phase I

(Colorado Public Utilities Commission Proceeding No. 23A-0585E)

December 1, 2023 April 22, 2024

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Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with 42 Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

Tri-State's Responsible Energy Plan (REP) issued in January of 2020 called for eliminating 100 percent of the carbon dioxide ("CO₂") emissions from Tri-State-owned coal generation in Colorado by 2030 and for 70 percent of the electricity used by its Members to come from clean sources by 2030. Tri-State has pursued an Electric Resource Plan (ERP) that aligns with its REP commitments.¹

This is Tri-State's Phase I ERP. The plan complies with Colorado Public Utilities Commission (Commission) Rule 3605 and relevant paragraphs of Decision No. R22-0191 in Proceeding No. 20A-0528E issued March 28, 2022, approving the Unopposed Comprehensive Settlement Agreement (2020 ERP Settlement Agreement) filed with the Commission on January 18, 2022, concluding Phase I of Tri-State's 2020 ERP. Attachment A to this report identifies the components of this report and 2023 ERP Phase I filing that comply with Commission directives.

The 20-year² resource planning period (RPP) for the 2023 ERP is 2024-2043 and the resource acquisition period (RAP) is the six-year³ period from 2026-2031. Although Tri-State evaluated "highly competitive"⁴ bids for 2026 in Phase II of the 2020 ERP, given that no projects were ultimately procured, Tri-State included 2026 in the 2023 ERP RAP to assess whether additional near-term resources might be selected under updated modeling input assumptions. Tri-State selected an acquisition period of six years through 2031 to ensure that, as fossil resource retirements in Colorado occur through the end of the decade, sufficient resources would be in place to continue to meet resource adequacy and reliability requirements. The RAP also recognizes the extended lead-time for certain resource types.

Tri-State's preferred plan for its ERP is the IRA Scenario. The preferred plan is reliable, affordable, and responsible. The plan brings online 1,540 MW of new resources during the RAP, including:

- 700 MW of wind (200 MW of wind hybrids);
- 310 MW of storage (110 MW of standalone 100-hour iron air batteries; 100 MW of standalone 4-hour batteries; and 100 MW of 4-hr batteries with wind hybrids);
- 290 MW of combined-cycle natural gas in 2028 (with carbon capture and sequestration in 2031); and
- 240 MW of solar.

These resource additions are forecasted to result in one of—the lowest present value revenue requirements (PVR) among the scenarios modeled, over the planning period if Tri-State is awarded

¹ The REP also identifies that Tri-State is striving for 100 percent clean energy in Colorado by 2040. While Phase I of the 2023 ERP does not yet forecast achievement of that stretch goal, Tri-State will continue to strive to make progress toward this aim in Phase II of the 2023 ERP and in the 2027 ERP. Notably, 2040 remains well outside of the Resource Acquisition Period (RAP) for the 2023 ERP.

² Commission Rule 3602(k).

³ Commission Rules 3602(n) and 3605(a)(IV)(A).

⁴ 2020 ERP Settlement Agreement, Section 3.4.4.2.

federal funding to support generation additions and provide stranded asset relief under the U.S. Department of Agriculture’s Empowering Rural America (New ERA) funding opportunity initiated by the Inflation Reduction Act of 2022 (IRA). The plan enables Tri-State to take full advantage of new direct pay of federal tax benefits for renewable and storage resources by increasing owned resources—while adding and maintaining PPA resources, which also helps to minimize renewable curtailment costs. The preferred plan also retires two coal-fired generation resources during the RAP, including:

- Craig Unit 3 (448 MW) on January 1, 2028; and
- Springerville Unit 3 (419 MW) on September 15, 2031.⁵

These significant shifts in Tri-State’s generation portfolio over the coming years would result in an 89 percent greenhouse gas (GHG) emissions reduction related to Tri-State’s wholesale sales of electricity in Colorado in 2030, over a 2005 baseline—more than any other scenario modeled in the 2023 ERP. The IRA Scenario results in the highest percentage of renewable generation capacity in 2030 (39 percent) while meeting all Level I and Level II reliability criteria, by maintaining sufficient dispatchable generation and bringing online new battery storage resources to ensure system performance during extreme weather events (EWEs).

Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data shows fourteen percent of the end-use customers served by Tri-State Members live below the federal poverty line, and up to half of the residential end-use customers suffer from some form of energy burden. The IRA has the potential to fundamentally alter the landscape for cooperative utilities. The IRA has “...tilt[ed] the balance in favor of cooperatives to develop their own renewables instead of utilizing purchase power agreements (PPAs). Thanks to the “direct-pay” provision in the law, cooperatives may now have a cost advantage depending on significant new grants from the U.S. Department of Agriculture (USDA) and the new ability to monetize tax credits that previously were available only to traditional developers with taxable income. These changes will have a big impact, as we saw when we compared renewables built by a representative cooperative versus an equivalent PPA...”⁶

Without new resource additions and assuming no change to previously announced generation retirement dates, with the exception of moving the Craig 3 retirement date to January 1, 2028, Tri-State would remain in a capacity-long position only through 2028, as identified in the 10-year loads and resources (L&R) shown in Table 1 below.⁷ Under the IRA Scenario, Tri-State would remain capacity-long throughout the planning period⁸, as shown in Figure 2 below.

⁵ Predicated on Tri-State receiving New ERA funding as requested and negotiation of contractual agreements impacted by the resource plan.

⁶ https://www.mcr-group.com/wp-content/uploads/2023/06/Coops-IRA-White-Paper_v3.pdf

⁷ In years where Tri-State files a Phase I ERP, the filing serves to comply with Commission Rule 3618(a) regarding ERP annual progress reports.

⁸ The IRA scenario graph is reflective of all generic resources selected throughout the RPP but Tri-State will only be acquiring resources in the RAP (2026 to 2031).

Table 1: Load & Resources (L&R)⁹

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3298	3212	3215	2818	2734	2746	2747	2753	2747
Total Obligations (MW)¹⁰	~~28262~~ <u>815</u>	~~27362~~ <u>725</u>	~~25162~~ <u>505</u>	~~25602~~ <u>549</u>	~~27332~~ <u>722</u>	~~28012~~ <u>790</u>	~~28272~~ <u>816</u>	~~28462~~ <u>835</u>	~~28972~~ <u>797</u>	~~29272~~ <u>827</u>
Excess (MW)	~~39840~~ <u>9</u>	~~56457~~ <u>2</u>	~~69770~~ <u>8</u>	~~65666~~ <u>7</u>	~~8495~~ <u>8495</u>	~~-6857~~ <u>-6857</u>	~~-8271~~ <u>-8271</u>	~~-9988~~ <u>-9988</u>	~~-14343~~ <u>-14343</u>	~~-18080~~ <u>-18080</u>

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Figure 1: Load & Resources (L&R)¹¹

⁹ No new resource additions from 2023 ERP modeling are included, reflects the current Tri-State system with known, contracted resource additions from previous procurements.

¹⁰ Includes Member load (less energy efficiency and Partial Requirements, with Beneficial Electrification), losses, planning and operating reserves, and contract sales.

¹¹ No new resource additions from 2023 ERP modeling are included, reflects the current Tri-State system with known, contracted resource additions from previous procurements.

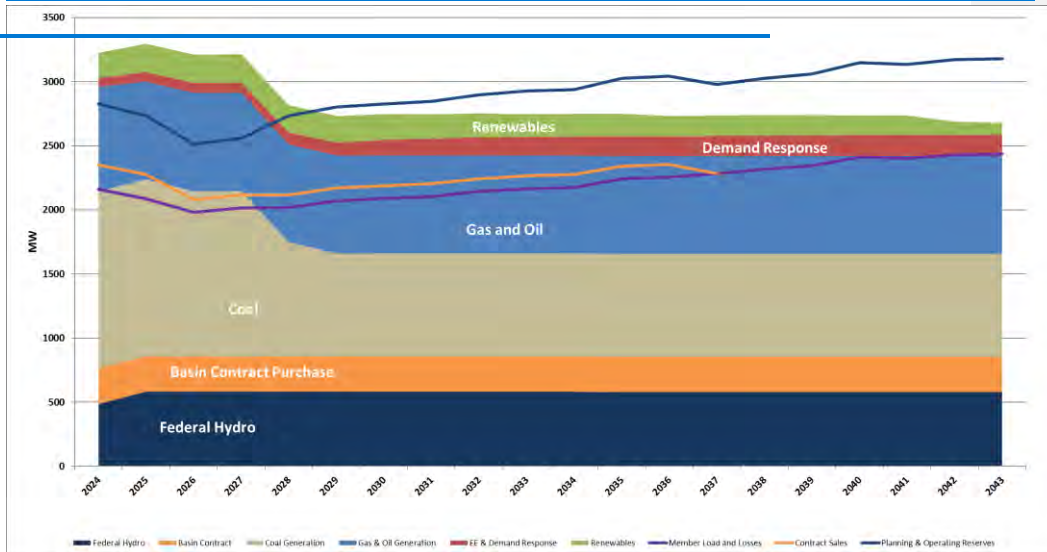
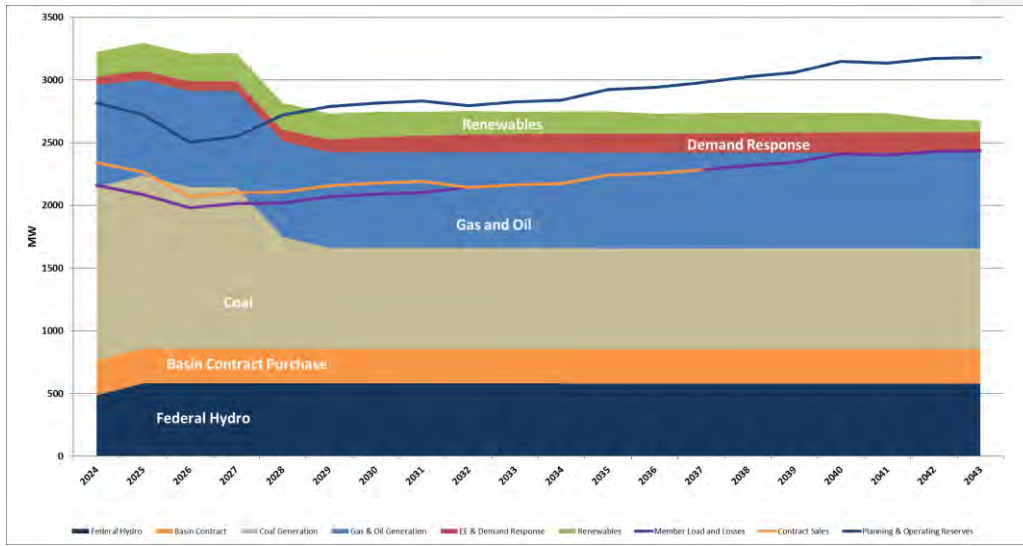


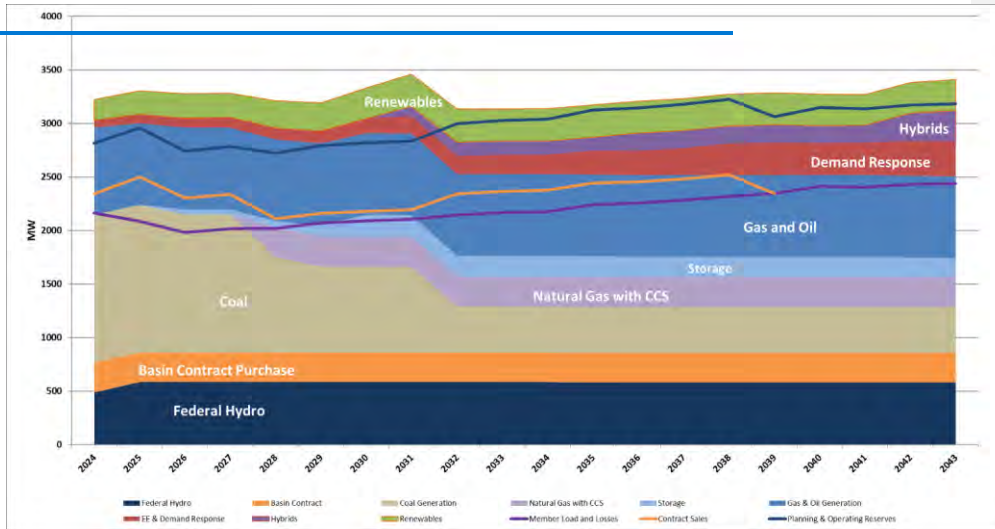
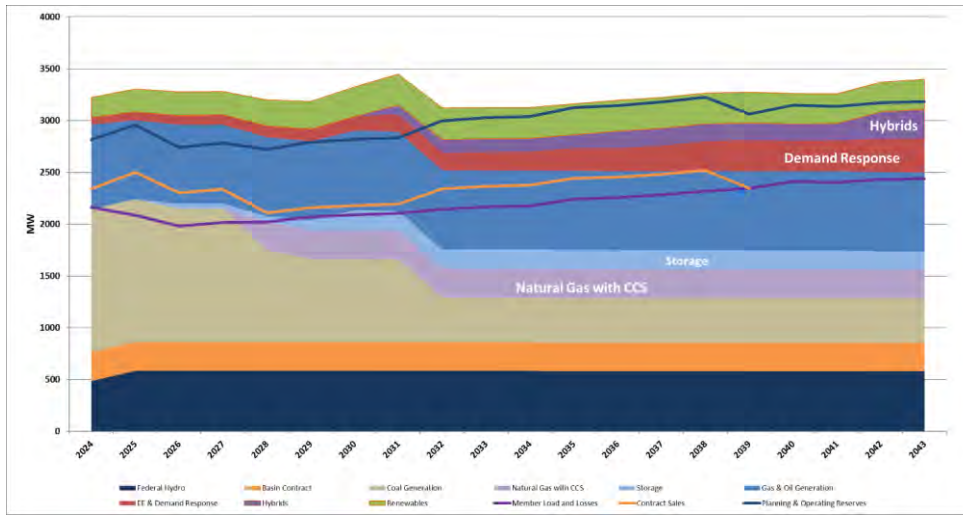
Table 2: Load & Resources (L&R), IRA Scenario

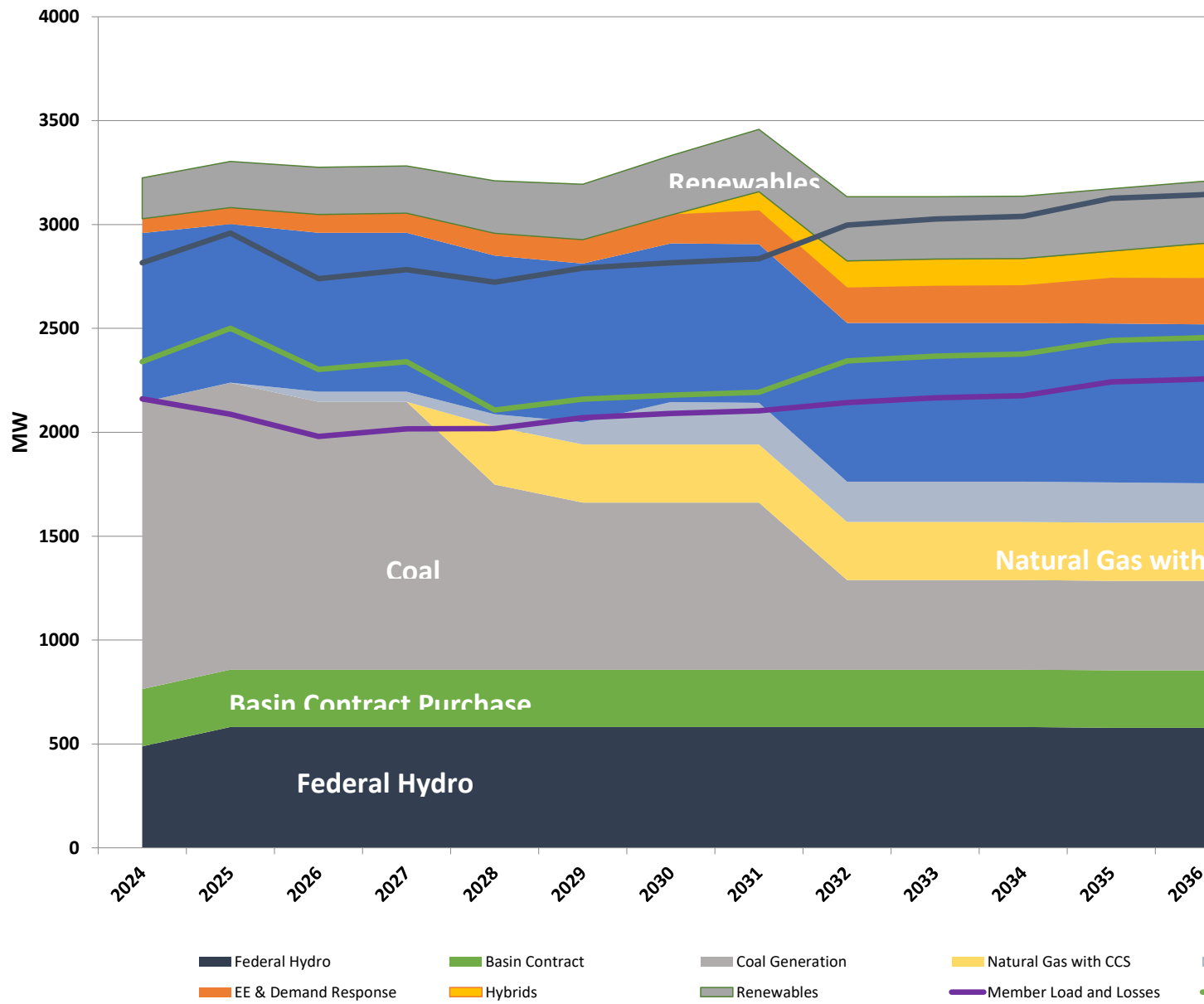
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3303	~~3286~~ <u>3276</u>	~~3291~~ <u>3281</u>	~~3210~~ <u>3201</u>	~~3193~~ <u>3184</u>	3332	~~3458~~ <u>3448</u>	~~3134~~ <u>3124</u>	~~3134~~ <u>3124</u>
Total Obligations (MW)¹²	~~2826~~ <u>2815</u>	~~2970~~ <u>2959</u>	~~2750~~ <u>2739</u>	~~2794~~ <u>2783</u>	~~2733~~ <u>2722</u>	~~2801~~ <u>2790</u>	~~2827~~ <u>2816</u>	~~2846~~ <u>2835</u>	2997	3027
Excess (MW)	~~398~~ <u>409</u>	~~333~~ <u>344</u>	~~536~~ <u>509</u>	~~498~~ <u>509</u>	~~477~~ <u>487</u>	~~392~~ <u>403</u>	~~504~~ <u>515</u>	~~612~~ <u>621</u>	~~137~~ <u>127</u>	~~107~~ <u>97</u>

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¹² Includes Member load (less energy efficiency and Partial Requirements, with Beneficial Electrification), losses, planning and operating reserves, and contract sales.

Figure 2: Load & Resources (L&R), IRA Scenario





¹³ Commission Rule 3605(a)(IV)(O).

Beneficial Electrification Potential Study	Mesa Point Energy	Evaluates the achievable potential to convert non-electrical load to electrical load within Tri-State's Utility Member System territories while reducing carbon emissions.	G-3 LKT-31
Demand Side Management/Energy Efficiency Potential Study	Mesa Point Energy	Evaluates Demand Side Management achievable potential in relation to energy efficiency and demand response across Tri-State's Utility Member Systems' territories.	G-3 LKT-31
Evaluation of Tri-State G&T Preferred Plan (IRA Scenario) Reliability	Astrape	Evaluates reliability of preferred plan (IRA Scenario) in 2032	G-4 LKT-32

Tri-State also received input from ACES to analyze Tri-State's forward power curve forecasting and potential benefits of offering new products in an organized market, as well as related model set-up.

Assessment of Existing Resources

Tri-State's assessment of existing resources is provided in Attachment C-3. Resources capable of self-supplying certain ancillary services are identified in Attachment B-4. Information on Tri-State's PPA and contract resources is provided in Attachment C-1. An analysis of the performance of Tri-State's existing resources was performed by the third-party consultant, provided as a Benchmarking Study (Attachment G-2).

Electric Energy and Demand Forecast

Attachments F-1 and F-2 contain Tri-State's load forecast summary and graphical presentation of load forecast data, pursuant to Commission Electric Rule 3605(a)(IV)(B) and 3605(b).

Scenario Modeling and Analysis Summary

Tri-State modeled five scenarios for Phase I of the 2023 ERP: 1) the Business-as-Usual (BAU), 2) IRA, 3) Early Springerville 3 Retirement (ESPV3), 4) System Wide Emissions Reductions (SWER), and 5) Aggressive Colorado Emissions Reductions (ACER). Both the BAU and IRA Scenarios include modeling input assumptions that Tri-State believes to be the most accurate and reflective of its system operations and Members' needs. Scenarios 3, 4, and 5 were modeled at the request of stakeholders.

Additionally, two¹⁴ sensitivity analyses were performed on each scenario's expansion plan to re-dispatch the plans under extreme weather event (EWE) and high gas (HG) price conditions. The EWE sensitivity modeling assumptions are provided in Attachment B-5 and results of the EWE sensitivity analyses are

¹⁴ Tri-State contemplated performing a drought sensitivity analysis for one year of the BAU Scenario, however, at the time 2023 ERP modeling began the U.S. Bureau of Reclamation's latest five-year projection for the Colorado River system indicated 0 percent probability of minimum power pool through 2027, so Tri-State deferred drought analysis to a future ERP.

provided in this report. The assumptions and results for the HG sensitivity analysis are provided in Attachment E. ^{LKT-25}

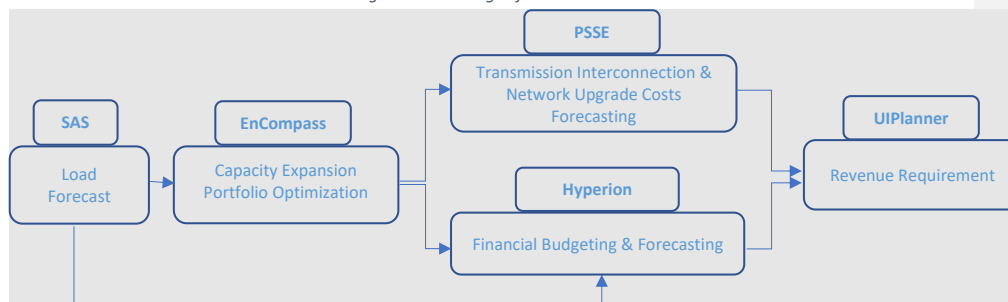
The Tri-State system is modeled as four planning regions. The planning regions are not state boundary restricted, rather they reflect significant power flow constraints within the Tri-State system:

- Wyoming / Electrically West Nebraska (WYO/WNE) – includes Tri-State owned or contracted resources capable of interconnecting north of TOT 3 in Wyoming and Nebraska located in the western interconnection and Western Area Colorado Missouri (WACM) Balancing Authority (BA);¹⁵ and Tri-State load identified as WACM BA Wyoming loads.
- Eastern Colorado (ECO) – includes Tri-State owned or contracted resources capable of connecting to transmission in Colorado south of TOT 3, east of TOT 5, and in the western interconnection and WACM BA; and Tri-State load identified as WACM BA east loads and Tri-State loads in Public Service Company of Colorado (PSCO) BA.
- Western Colorado (WCO) – includes Tri-State owned or contracted resources capable of connecting to transmission in Colorado north of TOT 2, west of TOT 5, and east of TOT 1 in WACM BA; and Tri-State load identified as WACM BA west load.
- New Mexico (NM) – includes Tri-State load and owned or contracted resources physically located in or pseudo-tied into Public Service of New Mexico (PNM) BA. PNM BA is located in New Mexico and a portion of southeast Colorado.

Additional detail on the Tri-State system reflected in the EnCompass model is available in Attachment B- ^{LKT-13}
6: Tri-State System Topology.

Figure 3 below identifies the software tools (SAS, EnCompass, PSSE, Hyperion, and UIPlanner) utilized by Tri-State for completing each component of the scenario analyses and the succession of data through each system.

Figure 3: Modeling Software Tools



¹⁵ TOTs represent a collection of transmission lines identified as a transfer path between regions.

Each scenario was evaluated in terms of its performance under reliability, financial, and environmental criteria, and state renewable policy compliance, as described below.

Expansion Plan, Retirements, System Mix, and Capacity Factors

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase I modeling, inputting the applicable modeling assumptions described in Attachment B^{LKT-7} and reflecting the Tri-State system topology, provided as Attachment B^{LKT-13}.

Environmental Analyses

Based on the expansion plan and dispatch produced for each scenario, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon (SCoC) and social cost of methane (SCoM). SCoC values reflect the February 2021 Interagency Working Group (IWG) on Social Cost of Greenhouse Gases, Technical Support Document.¹⁷

For each scenario, Tri-State separately produced an Air Pollution Control Division (APCD) verification workbook (APCD Workbook) calculating forecasted carbon emissions reductions, provided in Attachment D.^{LKT-18} Target-year emissions reductions percentages for each scenario, calculated from the APCD Workbooks, are provided in this report.

Tri-State used the most recent available EPA eGRID rates, year 2021, for forecasted market purchases and sales, the Basin Eastern Interconnection contract, and the Basin Electrically Western Interconnection contract. The carbon emission rate assumption for market purchases and sales is 1,159 pounds per MWh through 2029 per 2021 RMPA eGRID rate and 450 pounds per MWh (WECC), per APCD Workbook requirement, starting in 2030. The carbon emission rate assumption for Basin Western Interconnection contract is 2,596 pounds per MWh 2024 through 2025 per 2021 LRS eGRID rate, 1,159 pounds per MWh 2026 through 2029 per 2021 RMPA eGRID rate, and 450 pounds per MWh (WECC), per APCD Workbook requirement, starting in 2030. The carbon emission rate assumption for Basin Eastern Interconnection contract is 996 pounds per MWh through 2029, which is the 2021 MROW¹⁹ eGRID rate and 525 pounds per MWh (SPP), per APCD Workbook requirement starting in 2030.

Financial Analyses

Tri-State and 39 of our 42 Members serve 170 census tracts that are identified as Disadvantaged Communities, and 161 census tracts are identified as Low Income.²⁰ Pursuant to Rule 3605(g)(III)(C)(iii), Tri-State provided a financial analysis of each scenario, including:

- Annual revenue requirements;

¹⁶ See Attachments B, B-1, B-2, and B-3.
^{LKT-7, LKT-8, LKT-9, LKT-10}

¹⁷ https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

¹⁸ 2020 ERP Settlement Agreement, Section 3.11.1.

¹⁹ Midwest Reliability Organization West

²⁰ Council on Environmental Quality Climate and Economic Justice Screening Tool ([Explore the map - Climate & Economic Justice Screening Tool \(geoplatform.gov\)](#)), and USDA look-up map ([Locations of Distressed and Disadvantaged Communities \(arcgis.com\)](#)).

- Present value revenue requirement, with and without the social costs of carbon and methane; and
- Curtailment MWhs by intermittent resource type seasonally and year.²¹

Transmission Analyses

Each scenario was analyzed for its impact on transmission expenditures—both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades.

Reliability Analyses

Tri-State utilizes industry standard reliability metrics for its resource planning, referred to in the ERP as “Level I Reliability Metrics,” and has also developed an additional set of reliability metrics for assessing the plan’s performance under simulated EWE conditions, and refers to those standards as “Level II Reliability Metrics.” All metrics are given equal weight as minimum requirement thresholds for any scenario to be supported as a reliable, preferred plan for Tri-State.

These metrics are critical for mitigating risks associated with:

- Not meeting resource adequacy obligations as a load-serving entity (LSE);
- Reliability impacts during a single EWE as well as the impact of EWEs on reliability over the course of the RAP;
- Uncertainty of performance of emerging technologies and contribution of increased intermittent resources at higher levels;
- Lost productivity and cost of deploying emergency response measures during an EWE; and
- Member reliability expectations for high reliability across the system and limited load shedding or reduced system reliability during an EWE, and over time.

Level 1 reliability metric checks were performed on each scenario, including:

- *Planning Reserve Margin (PRM)*: Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%). The third-party study of PRM (Attachment ^{LKT-29}G-1) was developed using a Strategic Energy Risk Valuation Model (SERVM)—a system-reliability planning and production cost model designed to analyze the capabilities of an electric system during a variety of conditions under thousands of different scenarios and is thus able to identify potential risks to system reliability across the entire year, not just at system peak. The model, therefore, provides insight into risks and costs during these periods as well as the expectation of being able to meet peak load under many, varying conditions. The results of the model help determine the amount of reserves an electric system requires to adequately maintain system reliability.

²¹ One of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order. In the event that resources must be curtailed, Tri-State’s model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic min and must take contracts (i.e., hydropower and Basin contracts)—in that order.

- o Target (min) is 22% transitioning to 30.5% in 2028 after the retirement of the Craig facility.
- *Loss of Load Hours (LoLH)*²²: Measure of the likelihood of failing to meet system load (hours per 10 years).
 - o Target (max) is 1 day in 10 years (99.973% reliability).²³
 - 2024-2033 – annually cannot exceed 2.4 hours.²⁴
 - 2034-2043 – cannot exceed 24 hours over entire period.
- *Expected Unserved Energy (EUE)*²⁵: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
 - o Targets (max):
 - ≤ 0.4 GWh annually.²⁶

Level 2 reliability target checks were performed on each scenario's EWE sensitivity result, including:

- ≤ 12 loss of load hours during all EWEs in 2026-2031
- ≤ 3 loss of load hours per each year, 2026-2031
- EUE must be ≤ 20% of load in any hour²⁷
- Evaluation of market purchases vs remaining hourly available dispatchable capacity to ensure that EUE was not avoided through the use of market purchases as capacity.²⁸

A detailed analysis of how additions of new intermittent capacity can serve load and maintain reliability is provided for each scenario.²⁹

State Renewable Policy Compliance Analysis

Tri-State reviewed the results of each scenario and affirms that all scenarios meet or exceed the minimum applicable state renewable energy standard (RES) or renewable portfolio standard (RPS) requirements. RES/RPS standards are shown in the following table.

²² LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2020 ERP Phase I.

²³ Splitting the LOLH target over the planning period reflects Tri-State's desire to have added assurance that intra-year reliability in the near-term is met by resources coming online during the RAP as the generation fleet makes significant transitions through this period. This approach also allows Tri-State to cautiously assess the impact of having an increasing percentage of intermittent resources in its fleet and the uncertain potential for more severe EWEs before applying similarly stringent LOLH metrics to the outer years of the planning period. There is more flexibility allowed in the out years as forecasting and technology uncertainty is greater during this period.

²⁴ The annual LOLH target of 2.4 hours is an equivalent representation of the 1 day in 10 years reliability standard.

²⁵ EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.

²⁶ This metric is reflective of lower load forecasted based on both member exits and Partial Requirements and is aimed at limiting EUE to a reasonable level below the historical annual average, consistent with the 2020 ERP Phase II.

²⁷ This metric is an equivalent to the Level I annual EUE target, reflected as an hourly target to assess reliability during EWE stress periods. According to NREL, ~26 percent of estimated load in ERCOT was curtailed during Winter Storm Uri in 2021.

²⁸ In evaluating historical events, Tri-State confirmed that there was no reliance on third party capacity during extreme weather events. If market purchases occurred an equal or greater amount of Tri-State capacity was unused.

²⁹ 2020 ERP Settlement Agreement, Section 3.11.14.

Table 4: Colorado RES and New Mexico RPS Requirements during RPP

	Colorado RES ^{30, 31}		New Mexico RPS ³²
	Co-ops	Tri-State	Co-ops
2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%

Comparative Analysis

The analysis Tri-State completed to compare and assess results across scenarios can be found in the Comparative Analysis section of this report.

Commission Electric Rule 3605(g)(III)(C) and (D)

The Commission must consider the following factors in issuing a Phase I decision:

The Phase I decision will set forth the information the utility shall provide in the ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

Tri-State proposes an outline for the ERP Implementation Report to be filed in Phase II of the 2023 ERP, provided as Attachment LKT-3.

Tri-State proposes to procure utility-owned resources and PPAs, in alignment with the resource mix modeled in the IRA Scenario, shown in the table below. This approach would result in approximately 500 MW of owned resources and 1040 MW of PPA resources.

Table 5: Proposed MW of Utility-Owned and PPA Resources, by Technology, in IRA Scenario RAP

Technologies	Own	PPA
Solar		240
Wind		500
Wind Hybrid		200
4-hr Storage ³³	100	100
Iron Air Storage	110	
Natural Gas Combined Cycle (NGCC) with Carbon Capture and Sequestration (CCS) Conversion	290	
Total	500	1040

³⁰ § 40-2-124(1)(c)(I)(D) and (c)(V)(D), C.R.S.

³¹ § 40-2-124(8)(b), C.R.S.

³² N.M. Stat. Ann. § 62-15-34.

³³ Owned storage is standalone and PPA storage is tied to 200 MW of wind (wind hybrid).

The Commission shall determine the cost of carbon dioxide emissions to assess the cost, benefit, and net present value of revenue requirements to be presented in the ERP Implementation Report.

Tri-State has utilized the most recent IWG on Social Cost of Greenhouse Gases, Technical Support Document for the SCoC at the time modeling began and suggests continuation of that practice is sufficient for reporting portfolio analysis results in Phase II of the 2023 ERP.

In consideration of the base case portfolio of resources and alternative portfolios proposed by the utility, the Commission shall define the base case portfolio and alternative portfolios for modeling in Phase II.

If New ERA funding is received as requested, Tri-State requests that the IRA Scenario be the base case portfolio in Phase II. Tri-State proposes to model one portfolio that reflects the IRA Scenario resource selections and five portfolios that identifies back-up bid selections for each technology cohort. Tri-State requests limiting stakeholder-requested portfolios to two, given the number of back-up bid portfolios that will be necessary.

The Commission may require the utility to provide information regarding alternative portfolios in addition to the base case portfolio and information regarding the cost, benefit, and net present value of revenue requirements of the alternative portfolios using different levels of costs for carbon dioxide.

Tri-State has provided cost, benefit, and PVRs for five scenarios in Phase I, including a base case (Business as Usual Scenario), and would provide similar information for Phase II portfolios.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall establish the relevant factors other than the cost of carbon dioxide emissions for consideration of the approval of the utility's electric resource plan.

Factors that Tri-State has considered in evaluation of its preferred plan, the IRA Scenario, are identified in the Executive Summary and Comparative Analysis sections of this report. Factors include reliability, financial, and environmental considerations.

The Phase I decision will establish the deadline for the utility to submit its ERP Implementation Report.

Tri-State has proposed a Phase II timeline (Attachment LKT-2), which plans for the ERP Implementation Report to be filed 120 days after Bid Evaluation Complete (estimated to be January 2025). The proposed timeline for the ERP Implementation Report aims to ensure sufficient time for modeling preparation and completion, while recognizing RAP includes 2026.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in ongoing stakeholder engagement in advance of and during the Phase I resource planning process. Numerous stakeholder groups representing a diverse set of interests participated in more than a dozen meetings in 2023 in advance of Tri-State beginning Phase I modeling and several additional meetings during development of the Phase I filing. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform participants of key modeling inputs and assumptions, and facilitate dialogue on topics

applicable to Phase I. These stakeholder meetings occurred between January and October 2023, covering the following topics:

1. January 17, 2023: Phase I Scope, Timeline, Generic Resources, Storage Valuation, ELCCs, Scenarios/Sensitivities, and Phase II RFP³⁴
2. February 16, 2023: Beneficial Electrification (BE) Meeting #1³⁵
3. February 23, 2023: Phase I Storage Valuation, ELCCs, DSM/DR/BE,³⁶ and Scenarios/Sensitivities³⁷
4. March 10, 2023: Phase I Scenario and Sensitivity Planning #1³⁸
5. March 14, 2023: Phase I Reliability and Extreme Weather Event (EWE) Sensitivities
6. March 22, 2023: BE Meeting #2³⁹
7. March 24, 2023: Phase I Reliability and Extreme Weather Sensitivities
8. March 27, 2023: Phase I Scenario and Sensitivity Planning #2⁴⁰
9. April 24, 2023: Phase I Battery Modeling and ELCC Study⁴¹
10. April 26, 2023: DSM Roundtable Meeting #1
11. May 4, 2023: Phase I Scenario and Sensitivity Planning #3 (GHG Reduction Modeling)⁴²
12. May 17, 2023: Phase I Pre-Modeling Assumptions Feedback⁴³
13. July 19, 2023: Phase I PRM, ELCC, and EWE Modeling⁴⁴
14. August 14, 2023: Phase I Scenario and Sensitivity Planning #4⁴⁵
15. September 27, 2023: Phase II Planning⁴⁶
16. October 18, 2023: DSM Roundtable Meeting #2

Several other meetings, e-mail communications and updates to stakeholders also occurred in advance of and during Phase I modeling with the aim of ensuring communications on key ERP topics.⁴⁷ All 2023 ERP stakeholder meetings were identified on Tri-State's website⁴⁸ in advance of the meetings and were open for public participation.⁴⁹

³⁴ 2020 ERP Settlement Agreement, Sections 3.11.12., 3.11.13 and 3.11.15.

³⁵ 2020 ERP Settlement Agreement, Section 3.11.10.

³⁶ Per 2020 ERP Settlement Agreement, Sections 3.11.5, Tri-State held three meetings on DSM prior to December 31, 2022 which were identified in the 2020 ERP Phase II Implementation Report (April 27, June 14, and August 1, 2022). DSM modeling was also discussed during the February 23, 2023 stakeholder meeting.

³⁷ 2020 ERP Settlement Agreement, Sections 3.11.12, 3.11.13, and 3.11.14.

³⁸ 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.

³⁹ 2020 ERP Settlement Agreement, Section 3.11.10.

⁴⁰ 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.

⁴¹ 2020 ERP Settlement Agreement, Section 3.11.13.

⁴² 2020 ERP Settlement Agreement, Section 3.11.12.

⁴³ 2020 ERP Settlement Agreement, Section 3.11.12.

⁴⁴ 2020 ERP Settlement Agreement, Section 3.11.13.

⁴⁵ 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.

⁴⁶ Decision No. C23-0437, at ¶ 67.

⁴⁷ Of note, discussion of emissions rates occurred August 16, 2022, per 2020 ERP Settlement Agreement, Section 3.11.4, as identified in the 2020 ERP Phase II Implementation Report.

⁴⁸ <https://tristate.coop/resource-planning>

⁴⁹ 10 C.F.R. § 905.11(b)(4)

Tri-State maintains ongoing collaboration with interested stakeholders related to its ERP, federal funding pursuits, and organized market-related matters.

Scenario Results: Highlights

Key facets of the scenario modeling results, such as generic resource selection during the RAP, and unit retirements modeled and PVRs over the RPP are summarized below. Detailed scenario results and comparisons across scenarios are in the sections that follow.

Generic Resource Selection in Scenario Modeling

Table 6 identifies the generic resource types selected across the scenarios modeled.

Table 6: Generic Resources Selected in Scenario Modeling During the RAP, by MW and Technology

Scenario	Gas	Storage ⁵⁰	Solar ⁵¹	Wind	Wind Hybrid	Total
Scenario 1: BAU	290	250	140	0	300	980
Scenario 2: IRA	290	310	240	500	200	1,540
Scenario 3: ESPV3	290	350	140	0	300	1,080
Scenario 4: SWER	290	50	140	0	100	580
Scenario 5: ACER	290	100	140	0	200	730

Unit Retirement Selection in Scenario Modeling

Table 7 identifies the retirements dates modeled for resources during the RPP.

Table 7: Retirements Modeled by Scenario

Scenario	Craig 3	SPV 3	LRS 2
Scenario 1: BAU	1/1/2028	1/1/2037	1/1/2043
Scenario 2: IRA	1/1/2028	9/15/2031	N/A
Scenario 3: ESPV3	1/1/2028	1/1/2031	N/A
Scenario 4: SWER	1/1/2028	1/1/2037	N/A
Scenario 5: ACER	1/1/2028	1/1/2037	1/1/2042

Scenario PVRs

Error! Reference source not found. Table 8 identifies the PVRs resulting from each scenario modeled, over the RPP.

Table 8: PVR by Scenario

Scenario	PVR (\$, Millions)
Scenario 1: BAU	\$17,507.40
Scenario 2: IRA	\$17,221.35
Scenario 3: ESPV3	\$17,304.20
Scenario 4: SWER	\$17,343.90

⁵⁰ Storage inclusive of standalone and hybrid batteries.

⁵¹ Solar values are representative of selected generic resources during the RAP. Due to the cancellation of the Coyote Gulch after the start of modeling, 140 MW of solar replacement in 2026 will be pursued in Phase II and is reflected in this data.

Scenario 5: ACER	\$17,208.20

Phase I Scenario Results and Analysis

Each section that follows presents data and analytical results from each scenario modeled, addressed in the following order:

- Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales/Purchases
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

1. Business As Usual (BAU) Scenario

The BAU Scenario and assumptions served as the base case scenario for Phase I.⁵² Assumptions unique to each scenario are identified in Attachment B-3. ^{LKT-10}

Scenario 1 (BAU) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, DSM selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 9: Expansion Plan (Scenario 1 – BAU)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar ⁵³	West Colorado	140	1	140
2028	NGCC with CCS ⁵⁴	West Colorado	290	1	290
2030	Wind/Battery Hybrid	East Colorado	100	2	200
	100 hr – Iron Air Battery	East Colorado	100	1	100
2031	Wind/Battery Hybrid	New Mexico	100	1	100
2032	Wind/Battery Hybrid	East Colorado	100	1	100
2033	Wind	East Colorado	100	1	100
2036	Wind/Battery Hybrid	East Colorado	100	1	100
2037	Wind/Battery Hybrid	New Mexico	100	1	100
2040	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100
2041	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100
2042	Wind/Battery Hybrid	East Colorado	100	2	200
	Wind/Battery Hybrid	Wyoming / W. Neb.	100	2	200

⁵² Commission Rule 3605(a)(IV)(M).

⁵³ This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.

⁵⁴ NGCC installed in 2028 and CCS conversion startup anticipated in 2031.

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2043	Solar	New Mexico	100	1	100
	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:⁵⁵

- All plans include applicable Colorado energy efficiency targets in base assumptions.⁵⁶
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 1 – BAU in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 1 – BAU in 2040.

The expansion plan also included the following Demand Response (DR) levels by region:⁵⁷

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.⁵⁸
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 1 – BAU starting in 2040.
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 1 – BAU starting in 2038.

Unit retirements selected in the modeling are shown in the following table.⁵⁹

Table 10: Modeled Retirements (Scenario 1 – BAU)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037
LRS 2 (TS portion)	241	Coal	1/1/2043 ⁶⁰

Resulting system capacity and energy mix, based on the modeling are shown below.

⁵⁵ Commission Rule 3605(c)(I)(I).

⁵⁶ 2020 ERP Settlement Agreement at Section 3.11.6.

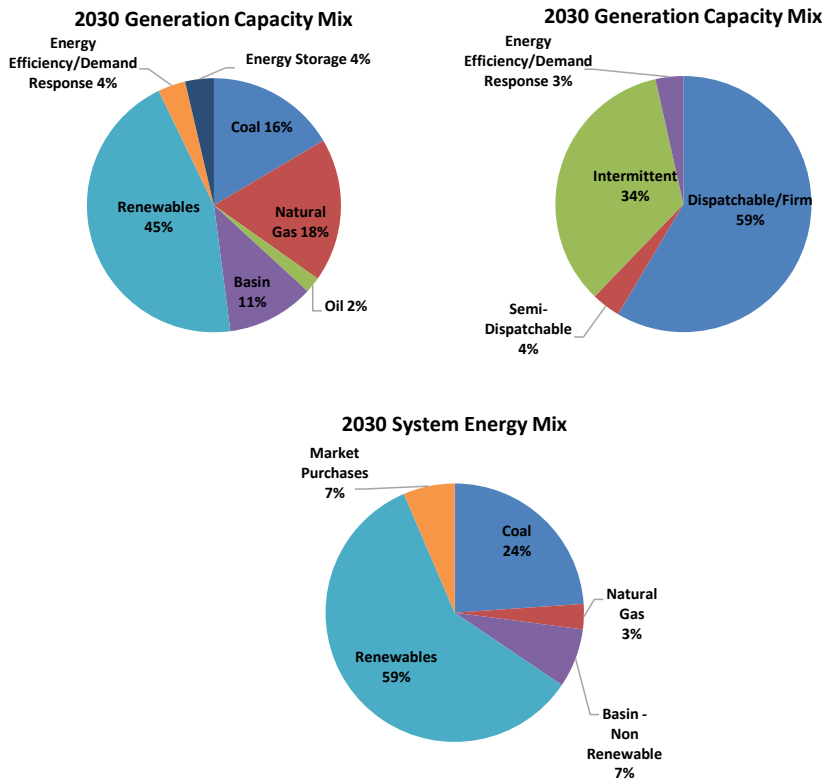
⁵⁷ Commission Rule 3605(c)(I)(I).

⁵⁸ 2020 ERP Settlement Agreement at Section 3.11.8.

⁵⁹ Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (“Yampa Project Owners”).

⁶⁰ This a modeling result based on input assumptions for Tri-State’s portion of Laramie River Station (LRS) Unit 2; at the time of this report, Tri-State does not have the right to unilaterally retire any Missouri Basin Power Project (MBPP) resource (LRS 2 or LRS 3). Tri-State along with MBPP participants will continue to evaluate changing industry regulations, system and market conditions to inform operational decisions related to its joint owned coal units.

Figure 4: Projected Tri-State System Resource Mix 2030 (Scenario 1 – BAU)^{61, 62, 63}



⁶¹ “Renewables” category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits (“RECs”) received via the Basin contract, and hydropower purchases.

⁶² Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.

⁶³ System Energy Mix reflects sales to Members and non-Members.

Table 11: Projected Annual Capacity Factors for Thermal Resources (Scenario 1 – BAU)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	18%	0%	0%	0%	0%	0%	0%
Craig 2	98%	15%	27%	12%	15%	0%	0%	0%
Craig 3	79%	13%	22%	18%	0%	0%	0%	0%
LRS 2	93%	89%	86%	78%	76%	74%	71%	70%
LRS 3	75%	63%	62%	55%	57%	48%	45%	51%
SPV 3	72%	67%	43%	42%	43%	36%	44%	42%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	26%	11%	0%	1%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	28%	28%	19%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 12: Forecasted Energy Sales and Purchases (Scenario 1 – BAU)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,534	1,506	3,095	2,877	3,344	2,774	3,286	3,911
Purchases (GWh)	344	946	523	884	610	717	926	742

Scenario 1 (BAU) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 13: Environmental Impact - System Wide (Scenario 1 – BAU)⁶⁴

Year	CO ₂ ⁶⁵ (ST)	SO ₂ (ST)	NO _x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH ₄ (MT CO _{2e})
2024	15,834,465	7,750	10,740	0.0383	704	6,777,851,478	32,082
2025	10,918,985	5,416	6,423	0.0243	515	4,098,496,075	20,000
2026 ⁶⁶	8,555,344	5,071	5,977	0.0230	413	3,640,953,702	18,040

⁶⁴ Commission Rule 3605(c)(l)(H). All tons are in short tons (ST), except for CH₄ which is provided as metric tons of carbon dioxide equivalent (MT CO_{2e}). CO₂, SO₂ and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

⁶⁵ In all scenarios the 2021 eGRID emission rate for LRS is used for calculating emissions of the Basin Western Interconnection Contract in 2024 and 2025. This is a change from reporting in the 2020 ERP which used regional eGRID rates in those years. From 2026 to 2029 the 2021 RMPA eGRID is used for this contract which then transitions to the APCD assigned rate for WECC in 2030.

⁶⁶ Load reduced due to partial requirements contracts in 2026 forward.

Year	CO ₂ ⁶⁵ (ST)	SO ₂ (ST)	NO _x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH ₄ (MT CO ₂ e)
2027	8,004,261	4,747	5,558	0.0204	378	3,239,042,574	16,444
2028	7,398,021	4,273	4,742	0.0182	384	3,109,973,662	14,569
2029	6,751,561	3,964	4,414	0.0161	336	2,752,993,696	12,908
2030	5,884,898	4,044	4,477	0.0161	350	2,732,958,152	13,397
2031	5,745,992	4,070	4,513	0.0166	370	3,287,323,551	13,629
2032	5,310,741	3,880	4,343	0.0153	333	3,053,750,612	12,597
2033	5,652,647	4,035	4,490	0.0162	361	3,227,998,157	13,431
2034	5,698,340	4,065	4,532	0.0163	362	3,244,468,138	13,533
2035	5,458,062	3,970	4,464	0.0157	339	3,116,848,744	12,923
2036	5,083,006	3,833	4,367	0.0149	302	2,923,162,545	12,018
2037	4,083,249	3,443	4,075	0.0130	206	2,443,989,009	9,470
2038	4,101,311	3,456	4,095	0.0130	206	2,447,420,964	9,511
2039	4,167,871	3,501	4,158	0.0132	208	2,466,937,312	9,661
2040	4,173,730	3,512	4,178	0.0131	207	2,460,238,397	9,674
2041	4,163,504	3,509	4,183	0.0130	205	2,442,136,997	9,651
2042	4,205,424	3,542	4,241	0.0130	205	2,439,323,762	9,744
2043	2,858,155	2,789	3,381	0.0071	127	1,651,568,018	6,808
Total	124,049,570	82,870	97,350	0.337	6,512	61,557,435,546	270,090
Pounds/Gallons per MWh ⁶⁷	857	0.57	0.67	0.000002	0.04	213	2.056

⁶⁷ Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 14: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 1 – BAU)

Year	Annual Social Cost of Carbon
2024	\$1,390,597,459
2025	\$995,687,914
2026	\$810,659,426
2027	\$787,912,259
2028	\$755,247,562
2029	\$714,655,955
2030	\$645,736,709
2031	\$653,860,869
2032	\$626,587,101
2033	\$691,336,216
2034	\$722,286,260
2035	\$716,850,786
2036	\$691,597,305
2037	\$575,435,014
2038	\$598,539,612
2039	\$629,766,814
2040	\$652,840,646
2041	\$670,965,445
2042	\$705,605,295
2043	\$494,486,160

Table 15: Social Cost of Methane Nominal Dollars – System Wide (Scenario 1 – BAU)

Year	Annual Social Cost of Methane
2024	\$82,734,317
2025	\$54,056,308
2026	\$51,119,484
2027	\$48,825,849
2028	\$45,233,558
2029	\$41,884,087
2030	\$45,409,865
2031	\$48,392,878
2032	\$46,826,362
2033	\$52,235,896
2034	\$55,037,923
2035	\$54,924,746
2036	\$53,357,940
2037	\$43,900,675
2038	\$46,012,180
2039	\$48,752,421
2040	\$50,897,483
2041	\$52,750,303
2042	\$56,102,875
2043	\$40,040,866

Table 16: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 1 – BAU)

Year	Target ⁶⁸	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	68%
2030	80%	86%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 1 (BAU) – Financial Analysis

The present value revenue requirement (PVR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

⁶⁸ 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Table 17: Total Financial (Scenario 1 – BAU)

\$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	\$17,507.4	\$11,608.8	\$800.2	\$29,116.2	\$29,916.4
Expansion Plan CapEx + IDC: Generation (Nominal \$)	\$1,806.8				
Expansion Plan CapEx + IDC: Transmission (Nominal \$)	\$598.2				

Table 18: Annual Financial (Nominal \$) (Scenario 1 – BAU)

Year	Total Annual Revenue Requirement (\$, Millions)
2024	\$1,016
2025	\$987
2026	\$898
2027	\$966
2028	\$1,053
2029	\$1,218
2030	\$1,262
2031	\$1,283
2032	\$1,305
2033	\$1,399
2034	\$1,503
2035	\$1,519
2036	\$1,562
2037	\$1,461
2038	\$1,490
2039	\$1,514
2040	\$1,534
2041	\$1,544
2042	\$1,566
2043	\$1,734

[Financial analysis of the of the scenario under the extreme-weather event stress is provided below.](#)

[Table 19-XX: Total Financial Under EWE Sensitivity \(Scenario 1 – BAU\)](#)

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Scenario PVRR (\$, Millions)
(2023 WACC 4.12%)
\$17,472.1

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 1 – BAU dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the investment tax credit (ITC) they do not have a production tax credit (PTC) penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 1 – BAU are \$518,551.

Table 20: Curtailed Intermittent Energy, Annual MWh (Scenario 1 – BAU)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	5,653	0	0	5,653
2027	0	3,345	0	0	3,345
2028	0	2,732	0	0	2,732
2029	0	2,193	0	0	2,193
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	0	13,923	0	0	13,923

Table 21: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 1 – BAU)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	125	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	0	0	0
RAP Total	150	11,870	86	1,817

The following table reflects PPA pricing, penalties, and taxes.

Table 22: Estimated PPA Curtailment Costs and Penalties, Real (2023) \$ (Scenario 1 – BAU)

	Wind (\$)	Solar (\$)
2024	0	0
2025	0	0
2026	0	\$208,078
2027	0	\$125,060
2028	0	\$102,674
2029	0	\$82,738
2030	0	0
2031	0	0
RAP Total	\$0	\$518,550

Scenario 1 (BAU) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the point of interconnection (POI), resulting from the scenario are shown in the table below.

Table 23: Transmission Interconnection & Network Upgrade Expenses Real (2023) \$ (Scenario 1 – BAU)

Year	Size (MW)	Type	Interconnection Cost (\$M)	Network Upgrade at POI Cost (\$M)	Network Upgrade for Size (\$M)
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		\$2.88	
2030	100	Wind + Battery		\$2.88	
2030	100	Battery	\$1.40	\$2.88	
2032	100	Wind + Battery		\$2.88	
2033	100	Wind		\$2.88	
2036	100	Wind + Battery		\$10.20	
2042	100	Wind + Battery		\$2.88	
2042	100	Wind + Battery		\$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	\$1.50	\$4.20	
Wyoming (WYO) Transmission Area					
2040	100	Wind + Battery		\$12.00	\$109.00
2041	100	Wind		\$4.20	
2042	100	Wind + Battery		\$4.20	
2042	100	Wind + Battery		\$4.20	\$34.00
2043	100	Wind + Battery		\$4.20	
New Mexico (NM) Transmission Area					
2031	100	Wind + Battery		\$2.88	\$238.50
2037	100	Wind + Battery		\$2.88	

Year	Size (MW)	Type	Interconnection Cost (\$M)	Network Upgrade at POI Cost (\$M)	Network Upgrade for Size (\$M)
2043	100	Solar		\$1.68	

Scenario 1 (BAU) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources’ ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 24: Planning Reserve Margin, % Annual (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	49%	42%	52%	54%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 25: Loss of Load Probability, Hours (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 26: Expected Unserved Energy, Annual MWh (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 1 – BAU)

Section 3.11.14. of the 2020 ERP Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment ^{LKT-29}G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 1 – BAU, 150 MW of 4-hour hybrid storage, 100 MW of long-duration storage, and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP, and support integration of intermittent resources.

Scenario 1 (BAU) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 27~~Table 26~~ represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all twelve EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the Scenario 1 – BAU extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours in Scenario 1 – BAU.

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Table 27: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 1 – BAU)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 28~~Table 27~~ represents any EUE identified by hour in the twelve EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

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Table 28: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 1 – BAU)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed EWE performance for Scenario 1 – BAU in the post-RAP period and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 1 – BAU)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the “analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access.”

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
 - o NM Market HE 2 to HE 6 and HE 11 to 15
 - o 1 day in event no market depth
- Summer:
 - o ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
 - o 1 day in event no market depth

In the EWE analysis for Scenario 1 – BAU, market was used for 6.4 GWh in 118 hours during the January EWE events between 2026-2031. The market was used for 11.9 GWh in 80 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

2. Inflation Reduction Act of 2022 (IRA) Scenario

Assumptions unique to each scenario are identified in Attachment B-3. ^{LKT-10}

Scenario 2 (IRA) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 29: Expansion Plan (Scenario 2 – IRA)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	4hr – Battery	New Mexico	50	1	50
	100hr – Iron Air Battery	East Colorado	10	1	10
	Solar ⁶⁹	West Colorado	140	1	140
2028	Wind	Wyoming / W. Neb.	100	2	200
	NGCC with CCS ⁷⁰	West Colorado	290	1	290
2029	Solar	New Mexico	100	1	100
	4hr – Battery	East Colorado	50	1	50
	Wind	East Colorado	100	1	100
2030	Wind	East Colorado	100	1	100
	Wind	Wyoming / W. Neb.	100	1	100
	100hr – Iron Air Battery	East Colorado	100	1	100
2031	Wind/Battery	New Mexico	100	2	200
2032	Wind/Battery	New Mexico	100	1	100
2036	Wind/Battery	East Colorado	100	1	100
2042	Wind/Battery	East Colorado	100	3	300
	Wind	Wyoming / W. Neb.	100	1	100
2043	Wind/Battery	Wyoming / W. Neb.	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:⁷¹

- All plans include applicable Colorado energy efficiency targets in base assumptions.⁷²
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 2 – IRA in 2025.

⁶⁹ This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.

⁷⁰ NGCC installed in 2028 and CCS conversion startup anticipated 2031.

⁷¹ Commission Rule 3605(c)(I)(I).

⁷² 2020 ERP Settlement Agreement at Section 3.11.6.

- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 2 – IRA in 2025.

The expansion plan also included the following Demand Response (DR) levels by region:⁷³

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.⁷⁴
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 2 – IRA starting in 2035.
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 2 – IRA starting in 2038.

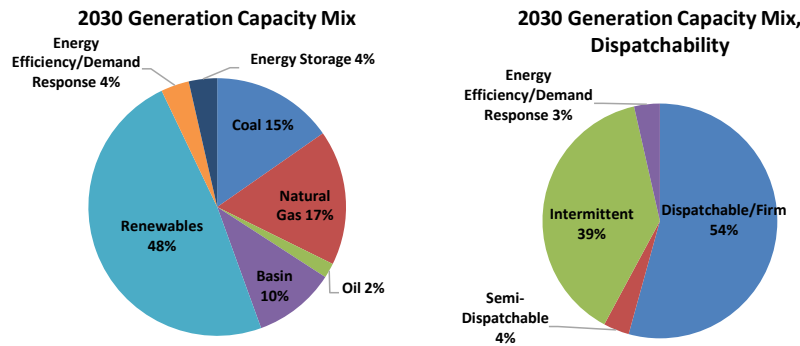
Unit retirements modeled are shown in the following table.⁷⁵

Table 30: Modeled Retirements (Scenario 2 – IRA)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	9/15/2031

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 5: Projected Tri-State System Resource Mix 2030 (Scenario 2 – IRA)^{76, 77, 78}



⁷³ Commission Rule 3605(c)(1)(i).

⁷⁴ 2020 ERP Settlement Agreement at Section 3.11.8.

⁷⁵ Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").

⁷⁶ "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.

⁷⁷ Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.

⁷⁸ System Energy Mix reflects sales to Members and non-Members.

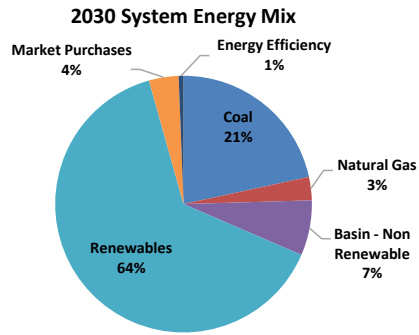


Table 31: Projected Annual Capacity Factors for Thermal Resources (Scenario 2 – IRA)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	18%	0%	0%	0%	0%	0%	0%
Craig 2	97%	16%	35%	25%	34%	0%	0%	0%
Craig 3	78%	12%	22%	17%	0%	0%	0%	0%
LRS 2	93%	89%	71%	71%	71%	68%	63%	64%
LRS 3	75%	64%	72%	60%	57%	55%	49%	50%
SPV 3	64%	66%	42%	42%	42%	36%	42%	37%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	0%	0%	0%	0%	0%	0%	0%
Shafer	26%	11%	1%	1%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	27%	25%	19%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 32: Forecasted Energy Sales and Purchases (Scenario 2 – IRA)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,304	1,499	3,067	2,873	3,957	3,883	4,259	5,014
Purchases (GWh)	283	952	515	813	422	422	542	512

Scenario 2 (IRA) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 33: Environmental Impact - System Wide (Scenario 2 – IRA)⁷⁹

Year	CO ₂ (ST)	SO ₂ (ST)	NO _x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH ₄ (MT CO ₂ e)
2024	15,451,106	7,595	10,593	0.0376	674	6,622,378,196	31,305
2025	10,888,923	5,401	6,381	0.0243	515	4,078,147,420	19,913
2026 ⁸⁰	8,468,490	4,994	5,893	0.0225	408	3,590,666,662	17,862
2027	7,993,868	4,710	5,504	0.0204	380	3,249,891,892	16,483
2028	7,253,155	4,178	4,625	0.0178	381	3,076,352,800	14,438
2029	6,563,974	3,928	4,348	0.0163	333	2,735,998,999	12,813
2030	5,608,261	3,884	4,262	0.0155	337	2,634,907,653	12,808
2031	4,831,239	3,643	4,079	0.0145	299	2,871,821,954	11,464
2032	3,824,819	3,280	3,865	0.0122	194	2,334,603,678	8,895
2033	3,933,841	3,345	3,952	0.0125	199	2,379,546,703	9,139
2034	3,964,238	3,367	3,982	0.0126	200	2,385,882,853	9,211
2035	3,927,079	3,349	3,971	0.0123	197	2,356,788,752	9,117
2036	3,985,696	3,392	4,021	0.0125	199	2,381,021,036	9,258
2037	4,022,648	3,417	4,064	0.0125	200	2,384,355,478	9,343
2038	4,021,708	3,421	4,072	0.0125	199	2,375,788,747	9,338
2039	3,974,658	3,373	3,968	0.0128	203	2,414,033,911	9,235
2040	3,998,873	3,400	4,018	0.0127	201	2,401,751,376	9,291
2041	3,983,443	3,399	4,036	0.0124	198	2,364,432,696	9,251
2042	4,027,793	3,434	4,095	0.0124	198	2,363,931,030	9,354
2043	4,013,781	3,433	4,106	0.0122	195	2,338,232,936	9,322
Total	114,737,592	78,943	93,836	0.318	5,707	57,340,534,771	247,837
Pounds/Gallons per MWh ⁸¹	792	0.55	0.65	0.000002	0.04	198	1.886

⁷⁹ Commission Rule 3605(c)(1)(H). All tons are in short tons (ST), except for CH₄ which is provided as metric tons of carbon dioxide equivalent (MT CO₂e). CO₂, SO₂ and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

⁸⁰ Load reduced due to partial requirements contracts in 2026 forward.

⁸¹ Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 34: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 2– IRA)

Year	Annual Social Cost of Carbon
2024	\$1,356,930,446
2025	\$992,946,534
2026	\$802,429,547
2027	\$786,889,198
2028	\$740,458,538
2029	\$694,799,728
2030	\$615,381,995
2031	\$549,767,216
2032	\$451,270,783
2033	\$481,120,934
2034	\$502,482,209
2035	\$515,774,643
2036	\$542,296,523
2037	\$566,894,764
2038	\$586,922,384
2039	\$600,572,264
2040	\$625,490,158
2041	\$641,947,763
2042	\$675,801,518
2043	\$694,419,551

Table 35: Social Cost of Methane Nominal Dollars – System Wide (Scenario 2 – IRA)

Year	Annual Social Cost of Methane
2024	\$80,730,077
2025	\$53,818,969
2026	\$50,613,362
2027	\$48,939,435
2028	\$44,826,979
2029	\$41,577,985
2030	\$43,413,041
2031	\$40,707,122
2032	\$33,064,168
2033	\$35,541,561
2034	\$37,457,706
2035	\$38,749,984
2036	\$41,103,874
2037	\$43,309,094
2038	\$45,174,789
2039	\$46,600,954
2040	\$48,883,426
2041	\$50,563,745
2042	\$53,858,083
2043	\$54,827,634

Table 36: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 2 – IRA)

Year	Target ⁸²	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	67%
2030	80%	89%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 2 (IRA) – Financial Analysis

The present value revenue requirement (PVR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

⁸² 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Table ~~37~~~~33~~~~36~~: Total Financial (Scenario 2 – IRA)

\$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	~~\$17,221.416~~ ~~352.0~~	\$10,726.7	\$733.1	~~\$27,948.127~~ ~~078.7~~	~~\$28,681.227~~ ~~811.8~~
Expansion Plan CapEx + IDC: Generation (Nominal \$)	\$2,093.9				
Expansion Plan CapEx + IDC: Transmission (Nominal \$)	\$555.5				

Table ~~38~~: Annual Financial (Nominal \$) (Scenario 2 – IRA)

Year	Total Annual Revenue Requirement (\$, Millions)
2024	~~\$1,017~~ ~~1,011~~
2025	~~\$969~~ ~~968~~
2026	~~\$904~~ ~~870~~
2027	~~\$962~~ ~~928~~
2028	~~\$1,104~~ ~~1,001~~
2029	~~\$1,231~~ ~~1,073~~
2030	~~\$1,258~~ ~~1,144~~
2031	~~\$1,301~~ ~~1,204~~
2032	~~\$1,285~~ ~~1,267~~
2033	~~\$1,317~~ ~~1,287~~
2034	~~\$1,349~~ ~~1,313~~
2035	~~\$1,379~~ ~~1,333~~
2036	~~\$1,416~~ ~~1,357~~
2037	~~\$1,440~~ ~~1,379~~
2038	~~\$1,464~~ ~~1,404~~
2039	~~\$1,506~~ ~~1,433~~
2040	~~\$1,566~~ ~~1,459~~
2041	~~\$1,593~~ ~~1,494~~
2042	~~\$1,601~~ ~~1,519~~
2043	~~\$1,700~~ ~~1,546~~

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

Table 39: Total Financial Under EWE Sensitivity (Scenario 2 – IRA)

Scenario PVRR (\$, Millions) (2023 WACC 4.12%)
\$17,166.816,300.1

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 2 – IRA dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 2 – IRA are \$503,718.

Table 40: Curtailed Intermittent Energy, Annual MWh (Scenario 2– IRA)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	75	0	0	75
2027	0	0	0	0	0
2028	0	287	0	0	287
2029	0	583	0	1,197	1,780
2030	0	376	0	203	579
2031	0	632	154	3,633	4,419
RAP Total	0	1,953	154	5,033	7,140

Table 41: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 2 – IRA)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	0	75	0	0
2027	0	0	0	0
2028	7	280	0	0
2029	1	1,572	0	207
2030	0	579	0	0
2031	0	3,902	13	504
RAP Total	8	6,408	13	711

The following table reflects PPA pricing, penalties, and taxes.

Table 42: Estimated PPA Curtailment Costs and Penalties, Real (2023) \$ (Scenario 2 – IRA)

	Wind (\$)	Solar (\$)
2024	0	0
2025	0	0
2026	0	\$2,816
2027	0	\$0
2028	0	\$9,596
2029	0	\$122,947
2030	0	\$29,692
2031	\$8,765	\$329,902
RAP Total	\$8,765	\$494,953

Scenario 2 (IRA) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 43: Transmission Interconnection & Network Upgrade Expenses Real (2023) \$ (Scenario 2 – IRA)

Year	Size (MW)	Type	Interconnection Cost (\$M)	Network Upgrade at POI Cost (\$M)	Network Upgrade for Size (\$M)
Eastern Colorado (ECO) Transmission Area					
2026	10	Battery	\$1.40	\$2.88	
2029	50	Battery	\$1.40	\$2.88	
2029	100	Wind		\$2.88	
2030	100	Wind		\$2.88	
2030	100	Battery	\$1.40	\$2.88	
2036	100	Wind + Battery		\$2.88	
2042	100	Wind		\$10.20	
2042	100	Wind		\$2.88	

Year	Size (MW)	Type	Interconnection Cost (\$M)	Network Upgrade at POI Cost (\$M)	Network Upgrade for Size (\$M)
2042	100	Wind		\$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	\$1.50	\$4.20	
Wyoming (WYO) Transmission Area					
2028	100	Wind		\$12.00	\$109.00
2028	100	Wind		\$4.20	
2030	100	Wind		\$4.20	
2042	100	Wind		\$4.20	\$26.00
2043	100	Wind + Battery		\$4.50	
New Mexico (NM) Transmission Area					
2026	50	Battery		\$2.88	
2029	100	Solar		\$1.68	
2031	100	Wind + Battery		\$2.88	\$238.50
2031	100	Wind + Battery		\$2.88	
2032	100	Wind + Battery		\$2.88	

Scenario 2 (IRA) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 44: Planning Reserve Margin, % Annual (Scenario2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	49%	47%	54%	50%	55%	60%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 45: Loss of Load Probability, Hours (Scenario 2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
0	1	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 46: Expected Unserved Energy, Annual MWh (Scenario 2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
0	1	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 2 – IRA)

Section 3.11.14. of the 2020 ERP Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment ^{LKT-29}G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 2 – IRA, 200 MW of short duration storage, 110 MW of long duration storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 2 (IRA) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 47: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year

(Scenario 2 – IRA) Table 47 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all twelve EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

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Table 47: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 2 – IRA)

Event (Season/Year)	Date	Hour
All Event Periods	N/A	N/A

Table 48 represents any EUE identified by hour in the twelve EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

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Table 48: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 2 – IRA)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All Event Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 2 –IRA)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the “analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access.”

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
 - o NM Market HE 2 to HE 6 and HE 11 to 15
 - o 1 day in event no market depth
- Summer:
 - o ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
 - o 1 day in event no market depth

In the EWE analysis for Scenario 2 – IRA, the market was used for 5.5 GWh in 97 hours during the January EWE events between 2026-2031. The market was used for 11.5 GWh in 79 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics.

Market purchases during these limited hours were confirmed to not lean on the market for capacity.

3. Early Springerville 3 Retirement Scenario (ESPV3)

LKT-10

Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 3 (ESPV3) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 49: Expansion Plan (Scenario 3 – ESPV3)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar ⁸³	West Colorado	140	1	140
2028	4hr – Battery	West Colorado	50	1	50
	NGCC with CCS ⁸⁴	West Colorado	290	1	290
2030	Wind/Battery	East Colorado	100	1	100
2031	4hr – Battery	West Colorado	50	1	50
	Wind/Battery	New Mexico	100	2	200
	100hr – Iron Air Battery	East Colorado	100	1	100
2036	Wind	East Colorado	100	1	100
2037	Wind	East Colorado	100	2	200
2039	Wind/Battery	Wyoming / W. Neb.	100	1	100
2040	Wind/Battery	Wyoming / W. Neb.	100	1	100
2041	Wind	Wyoming / W. Neb.	100	2	200
2042	Wind/Battery	East Colorado	100	3	300
2043	Solar	New Mexico	100	1	100
	Wind/Battery	Wyoming / W. Neb.	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:⁸⁵

- All plans include applicable Colorado energy efficiency targets in base assumptions.⁸⁶
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 3 – ESPV3 in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 3 – ESPV3 in 2040.

⁸³ This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.

⁸⁴ NGCC installed in 2028 and CCS conversion startup anticipated in 2031.

⁸⁵ Commission Rule 3605(c)(I)(I).

⁸⁶ 2020 ERP Settlement Agreement at Section 3.11.6.

The expansion plan also included the following Demand Response (DR) levels by region:⁸⁷

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.⁸⁸
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 3 – ESPV3 starting in 2031.
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 3 – ESPV3 starting in 2031

Unit retirements selected in the modeling are shown in the following table.⁸⁹

Table 50: Modeled Retirements (Scenario 3 –ESPV3)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2031

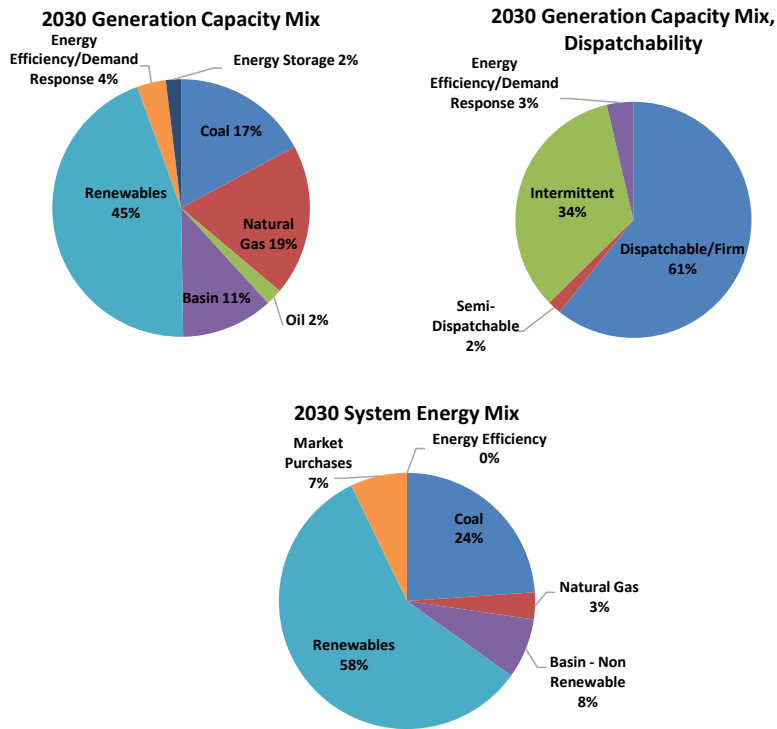
Resulting system capacity and energy mix, based on the modeling are shown below.

⁸⁷ Commission Rule 3605(c)(I)(I).

⁸⁸ 2020 ERP Settlement Agreement at Section 3.11.8.

⁸⁹ Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (“Yampa Project Owners”).

Figure 6: Projected Tri-State System Resource Mix 2030 (Scenario 3 – ESPV3)^{90, 91, 92}



⁹⁰ “Renewables” category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits (“RECs”) received via the Basin contract, and hydropower purchases.

⁹¹ Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.

⁹² System Energy Mix reflects sales to Members and non-Members.

Table 51: Projected Annual Capacity Factors for Thermal Resources (Scenario 3 – ESPV3)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	16%	0%	0%	0%	0%	0%	0%
Craig 2	98%	9%	34%	23%	20%	0%	0%	0%
Craig 3	79%	14%	22%	16%	0%	0%	0%	0%
LRS 2	93%	89%	71%	71%	71%	69%	63%	64%
LRS 3	75%	64%	70%	60%	58%	51%	48%	54%
SPV 3	72%	67%	43%	42%	43%	37%	44%	0%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	24%	11%	1%	0%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	29%	28%	20%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 52: Forecasted Energy Sales and Purchases (Scenario 3 – ESPV3)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,505	1,506	3,044	2,850	3,312	2,712	3,018	3,098
Purchases (GWh)	355	946	545	852	623	722	1,004	1,167

Scenario 3 (ESPV3) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 53: Environmental Impact - System Wide (Scenario 3 – ESPV3)⁹³

Year	CO ₂ (ST)	SO ₂ (ST)	NO _x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH ₄ (MT CO _{2e})
2024	15,839,102	7,764	10,741	0.0383	704	6,772,194,117	32,129
2025	10,919,154	5,447	6,450	0.0245	513	4,099,792,207	19,995
2026 ⁹⁴	8,469,494	4,985	5,874	0.0224	409	3,579,117,374	17,834
2027	7,999,822	4,707	5,493	0.0203	381	3,238,736,958	16,456
2028	7,332,465	4,209	4,671	0.0177	380	3,069,522,031	14,392
2029	6,711,585	3,942	4,388	0.0160	333	2,727,887,902	12,834
2030	5,808,252	3,998	4,428	0.0157	345	2,680,280,773	13,221

⁹³ Commission Rule 3605(c)(1)(H). All tons are in short tons (ST), except for CH₄ which is provided as metric tons of carbon dioxide equivalent (MT CO_{2e}). CO₂, SO₂ and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

⁹⁴ Load reduced due to partial requirements contracts in 2026 forward.

Year	CO ₂ (ST)	SO ₂ (ST)	NO _x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH ₄ (MT CO ₂ e)
2031	3,936,370	3,337	3,931	0.0126	201	2,399,903,106	9,134
2032	3,835,588	3,290	3,891	0.0121	193	2,324,000,130	8,911
2033	3,950,512	3,360	3,986	0.0124	198	2,369,472,111	9,166
2034	3,982,627	3,382	4,019	0.0125	199	2,377,578,327	9,240
2035	3,951,406	3,370	4,016	0.0122	196	2,345,304,444	9,165
2036	4,026,737	3,423	4,077	0.0125	199	2,380,608,886	9,347
2037	4,060,785	3,435	4,078	0.0128	203	2,416,104,215	9,428
2038	4,051,989	3,435	4,086	0.0126	201	2,399,586,707	9,406
2039	4,098,100	3,460	4,108	0.0129	204	2,432,494,784	9,515
2040	4,094,950	3,467	4,124	0.0128	203	2,419,226,942	9,510
2041	4,088,441	3,459	4,110	0.0128	203	2,420,432,239	9,492
2042	4,131,169	3,499	4,190	0.0127	201	2,399,136,160	9,588
2043	4,099,795	3,483	4,170	0.0125	199	2,380,264,589	9,520
Total	115,388,344	79,453	94,833	0.318	5,667	57,231,644,003	248,282
Pounds/Gallons per MWh ⁹⁵	797	0.55	0.65	0.000002	0.04	198	1.890

Table 54: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 3 – ESVP3)

Year	Annual Social Cost of Carbon
2024	\$1,391,004,648
2025	\$995,703,293
2026	\$802,524,764
2027	\$787,475,263
2028	\$748,555,145
2029	\$710,424,496
2030	\$637,326,494
2031	\$447,936,321
2032	\$452,541,393
2033	\$483,159,901
2034	\$504,813,123
2035	\$518,969,660
2036	\$547,880,617
2037	\$572,269,158
2038	\$591,341,514
2039	\$619,224,271
2040	\$640,518,145
2041	\$658,868,730
2042	\$693,146,438
2043	\$709,300,764

⁹⁵ Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 55: Social Cost of Methane Nominal Dollars – System Wide (Scenario 3 – ESPV3)

Year	Annual Social Cost of Methane
2024	\$82,855,374
2025	\$54,041,930
2026	\$50,535,594
2027	\$48,861,264
2028	\$44,684,056
2029	\$41,645,072
2030	\$44,814,668
2031	\$32,432,806
2032	\$33,124,403
2033	\$35,647,372
2034	\$37,577,397
2035	\$38,954,135
2036	\$41,497,117
2037	\$43,705,831
2038	\$45,503,307
2039	\$48,013,151
2040	\$50,034,448
2041	\$51,880,457
2042	\$55,205,912
2043	\$55,991,156

Table 56: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 3 – ESPV3)

Year	Target ⁹⁶	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	67%
2030	80%	85%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 3 (ESPV3) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

⁹⁶ 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Table 57: Total Financial (Scenario 3 – ESPV3)

\$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	\$17,304.2	\$10,789.6	\$734.8	\$28,093.8	\$28,828.6
Expansion Plan CapEx + IDC: Generation (Nominal \$)	\$1,983.6				
Expansion Plan CapEx + IDC: Transmission (Nominal \$)	\$590.6				

Table 58: Annual Financial (Nominal \$) (Scenario 3 – ESPV3)

Year	Total Annual Revenue Requirement (\$, Millions)
2024	\$1,016
2025	\$988
2026	\$904
2027	\$962
2028	\$1,060
2029	\$1,178
2030	\$1,441
2031	\$1,335
2032	\$1,345
2033	\$1,361
2034	\$1,382
2035	\$1,404
2036	\$1,428
2037	\$1,450
2038	\$1,474
2039	\$1,495
2040	\$1,514
2041	\$1,529
2042	\$1,546
2043	\$1,562

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

Table 59XX: Total Financial Under EWE Sensitivity (Scenario 3 – BAU/ESPV3)

Scenario PVRR (\$, Millions)
(2023 WACC 4.12%)

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\$17,472,1275.6

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 3 – ESPV3 dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 3 – ESPV3 are \$520,955.

Table 60: Curtailed Intermittent Energy, Annual MWh (Scenario 3 – ESPV3)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	5,640	0	0	5,640
2027	0	3,345	0	0	3,345
2028	0	2,732	0	0	2,732
2029	0	2,193	0	0	2,193
2030	0	0	0	0	0
2031	0	0	44	0	44
RAP Total	0	13,910	44	0	13,954

Table 61: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 3 – ESPV3)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	112	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	44	0	0
RAP Total	137	11,914	86	1,817

The following table reflects PPA pricing, penalties, and taxes.

Table 62: Estimated PPA Curtailment Costs and Penalties, Real (2023) \$ (Scenario 3 – ESPV3)

	Wind (\$)	Solar (\$)
2024	\$0	\$0
2025	\$0	\$0
2026	\$0	\$208,309
2027	\$0	\$124,914
2028	\$0	\$102,651
2029	\$0	\$82,570
2030	\$0	\$0
2031	\$2,511	\$0
RAP Total	\$2,511	\$518,444

Scenario 3 (ESPV3) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 63: Transmission Interconnection & Network Upgrade Expenses Real (2023) \$ (Scenario 3 – ESPV3)

Year	Size (MW)	Type	Interconnection Cost (\$M)	Network Upgrade at POI Cost (\$M)	Network Upgrade for Size (\$M)
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		\$2.88	
2031	100	Battery	\$1.40	\$2.88	
2036	100	Wind		\$10.20	
2037	100	Wind		\$2.88	
2037	100	Wind		\$2.88	
2042	100	Wind + Battery		\$2.88	
2042	100	Wind + Battery		\$2.88	
2042	100	Wind + Battery		\$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	\$1.50	\$4.20	
2028	50	Battery	\$1.40	\$2.88	
2031	50	Battery	\$1.40	\$2.88	
Wyoming (WYO) Transmission Area					
2039	100	Wind + Battery		\$12.00	\$109.00
2040	100	Wind + Battery		\$4.20	
2041	100	Wind		\$4.20	
2041	100	Wind		\$4.20	\$26.00
2043	100	Wind + Battery		\$4.20	
New Mexico (NM) Transmission Area					

Year	Size (MW)	Type	Interconnection Cost (\$M)	Network Upgrade at POI Cost (\$M)	Network Upgrade for Size (\$M)
2031	100	Wind + Battery		\$2.88	\$238.50
2031	100	Wind + Battery		\$2.88	
2043	100	Solar		\$1.68	

Scenario 3 (ESPV3) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources’ ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 64: Planning Reserve Margin, % Annual (Scenario 3 – ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	52%	44%	47%	48%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 65: Loss of Load Probability, Hours (Scenario 3 – ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 66: Expected Unserved Energy, Annual MWh (Scenario 3 – ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 3 – ESPV3)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment ^{LKT-29}G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 3 – ESPV3, 250 MW of 4-hr storage, 100 MW of long-duration storage, and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable

resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 3 (ESPV3) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 67~~Table 65~~ represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

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Table 67: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 3 – ESPV3)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 68~~Table 66~~ represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

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Table 68: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 3 – ESPV3)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 3 – ESPV3)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the “analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access.”

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
 - NM Market HE 2 to HE 6 and HE 11 to 15
 - 1 day in event no market depth
- Summer:
 - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
 - 1 day in event no market depth

In the EWE analysis for Scenario 3—ESPV3, the market was used for 7.4 GWh in 131 hours during the January EWE events between 2026-2031. The market was used for 14.3 GWh in 85 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

4. System-wide Emissions Reduction Scenario (SWER) LKT-10

Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 4 (SWER) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 69: Expansion Plan (Scenario 4 – SWER)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar ⁹⁷	West Colorado	140	1	140
2029	NGCC with CCS ⁹⁸	West Colorado	290	1	290
2030	Wind/Battery	East Colorado	100	1	100
2033	Wind	New Mexico	100	1	100
	Wind/Battery	New Mexico	100	1	100
2034	Wind/Battery	East Colorado	100	1	100
2036	Wind/Battery	East Colorado	100	1	100
2037	Wind/Battery	New Mexico	100	1	100
2038	Wind/Battery	East Colorado	100	1	100
2040	Wind/Battery	Wyoming / W. Neb.	100	1	100
2041	Wind	Wyoming / W. Neb.	100	2	200
2042	Wind	East Colorado	100	1	100
	Wind/Battery	East Colorado	100	2	200
2043	Solar – Build Transfer	West Colorado	100	3	300
	Solar	New Mexico	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:⁹⁹

- All plans include applicable Colorado energy efficiency targets in base assumptions.¹⁰⁰

⁹⁷ This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.

⁹⁸ NGCC installed in 2029 and CCS conversion startup anticipated in 2031.

⁹⁹ Commission Rule 3605(c)(I)(I).

¹⁰⁰ 2020 ERP Settlement Agreement at Section 3.11.6.

The expansion plan also included the following Demand Response (DR) levels by region:¹⁰¹

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.¹⁰²
- 39 MW of Wyoming low level Demand Response was selected in the expansion plan of Scenario 4 – SWER starting in 2030.
- 117 MW New Mexico moderate level Demand Response was selected in the expansion plan of Scenario 4 – SWER starting in 2039.

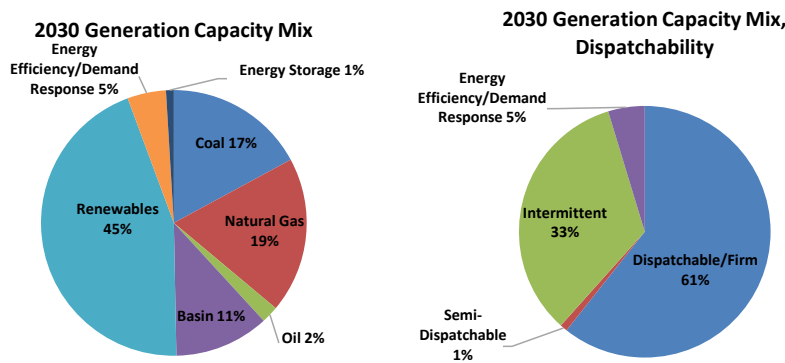
Unit retirements selected in the modeling are shown in the following table.¹⁰³

Table 20: Modeled Retirements (Scenario 4 – SWER)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 7: Projected Tri-State System Resource Mix 2030 (Scenario 4- SWER)^{104, 105, 106}



¹⁰¹ Commission Rule 3605(c)(1)(I).

¹⁰² 2020 ERP Settlement Agreement at Section 3.11.8.

¹⁰³ Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").

¹⁰⁴ "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.

¹⁰⁵ Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.

¹⁰⁶ System Energy Mix reflects sales to Members and non-Members.

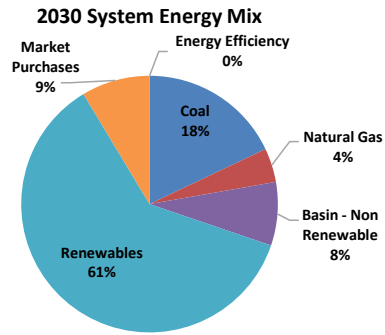


Table 71: Projected Annual Capacity Factors for Thermal Resources (Scenario 4 - SWER)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	17%	0%	0%	0%	0%	0%	0%
Craig 2	98%	16%	26%	13%	36%	0%	0%	0%
Craig 3	79%	13%	25%	19%	0%	0%	0%	0%
LRS 2	93%	89%	71%	72%	71%	67%	41%	16%
LRS 3	75%	64%	69%	57%	58%	50%	30%	13%
SPV 3	72%	67%	43%	42%	45%	36%	37%	36%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	27%	11%	0%	1%	1%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	0%	29%	24%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 72: Forecasted Energy Sales and Purchases (Scenario 4 - SWER)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,561	1,496	3,063	2,872	2,902	2,615	2,245	1,687
Purchases (GWh)	346	941	550	912	748	658	1,154	1,265

Scenario 4 (SWER) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 73: Environmental Impact - System Wide (Scenario 4 - SWER)¹⁰⁷

Year	CO ₂ (ST)	SO ₂ (ST)	NO _x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH ₄ (MT CO ₂ e)
2024	15,863,704	7,761	10,763	0.0383	705	6,793,247,708	32,133
2025	10,919,812	5,420	6,407	0.0244	516	4,098,699,996	19,995
2026 ¹⁰⁸	8,477,517	5,026	5,962	0.0225	404	3,583,422,154	17,903
2027	7,972,529	4,721	5,542	0.0202	374	3,210,051,302	16,365
2028	7,358,120	4,302	4,787	0.0182	377	2,927,811,446	14,845
2029	6,573,723	3,872	4,303	0.0156	327	2,680,149,760	12,556
2030	4,514,050	3,295	3,646	0.0108	262	1,990,503,327	10,296
2031	3,157,659	2,666	2,918	0.0062	212	1,818,549,023	7,869
2032	3,203,866	2,736	3,048	0.0067	205	1,845,960,399	7,905
2033	3,208,225	2,703	2,972	0.0063	213	1,829,638,245	7,985
2034	3,226,798	2,710	2,973	0.0064	215	1,851,008,307	8,024
2035	3,254,631	2,763	3,078	0.0069	208	1,876,225,341	8,012
2036	3,315,308	2,850	3,219	0.0077	200	1,929,252,664	8,076
2037	3,614,749	3,177	3,763	0.0110	179	2,178,755,684	8,428
2038	3,622,455	3,180	3,760	0.0111	181	2,189,879,374	8,448
2039	3,611,385	3,180	3,770	0.0110	178	2,169,009,462	8,423
2040	3,596,535	3,182	3,782	0.0108	176	2,145,151,059	8,397
2041	3,613,093	3,188	3,781	0.0109	178	2,160,677,499	8,433
2042	3,585,634	3,191	3,825	0.0104	171	2,091,352,778	8,369
2043	3,610,874	3,196	3,807	0.0107	175	2,135,484,251	8,432
Total	106,300,669	73,119	86,106	0.266	5,456	51,504,829,781	230,898
Pounds/Gallons per MWh ¹⁰⁹	734	0.50	0.59	0.000002	0.04	178	1.757

¹⁰⁷ Commission Rule 3605(c)(1)(H). All tons are in short tons (ST), except for CH₄ which is provided as metric tons of carbon dioxide equivalent (MT CO₂e). CO₂, SO₂ and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

¹⁰⁸ Load reduced due to partial requirements contracts in 2026 forward.

¹⁰⁹ Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 74: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 4 – SWER)

Year	Annual Social Cost of Carbon
2024	\$1,393,165,248
2025	\$995,763,266
2026	\$803,284,931
2027	\$784,788,638
2028	\$751,174,190
2029	\$695,831,712
2030	\$495,316,652
2031	\$359,323,495
2032	\$378,007,746
2033	\$392,375,842
2034	\$409,008,952
2035	\$427,456,666
2036	\$451,083,112
2037	\$509,411,285
2038	\$528,656,041
2039	\$545,681,555
2040	\$562,557,798
2041	\$582,264,404
2042	\$601,614,118
2043	\$624,713,086

Table 75: Social Cost of Methane Nominal Dollars – System Wide (Scenario 4 - SWER)

Year	Annual Social Cost of Methane
2024	\$82,867,370
2025	\$54,042,415
2026	\$50,729,638
2027	\$48,591,361
2028	\$46,092,106
2029	\$40,743,674
2030	\$34,900,045
2031	\$27,942,182
2032	\$29,384,966
2033	\$31,054,907
2034	\$32,634,103
2035	\$34,054,127
2036	\$35,858,109
2037	\$39,068,247
2038	\$40,865,813
2039	\$42,504,595
2040	\$44,182,882
2041	\$46,091,559
2042	\$48,190,439
2043	\$49,596,337

Table 76: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 4 - SWER)

Year	Target ¹¹⁰	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	68%
2030	80%	82%

Table 77: System-wide GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 4 - SWER)

Year	Target ¹¹¹	Forecast
2027	20.9%	44%
2028	33.2%	44%
2029	45.4%	51%
2030	57.7%	61%
2031	70%	73%

See Appendix D for detailed GHG emissions calculations for the scenario.

¹¹⁰ 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

¹¹¹ 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Scenario 4 (SWER) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

Table 78: Total Financial (Scenario 4 - SWER)

\$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	\$17,343.9	\$9,899.2	\$679.1	\$27,243.1	\$27,922.2
Expansion Plan CapEx + IDC: Generation (Nominal \$)	\$1,694.1				
Expansion Plan CapEx + IDC: Transmission (Nominal \$)	\$546.3				

Table 79: Annual Financial (Nominal \$) (Scenario 4 - SWER)

Year	Total Annual Revenue Requirement (\$, Millions)
2024	\$1,016
2025	\$978
2026	\$894
2027	\$957
2028	\$1,003
2029	\$1,092
2030	\$1,232
2031	\$1,270
2032	\$1,434
2033	\$1,459
2034	\$1,497
2035	\$1,512
2036	\$1,534
2037	\$1,421
2038	\$1,445
2039	\$1,497
2040	\$1,518
2041	\$1,536
2042	\$1,557
2043	\$1,730

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Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

Table 80XX: Total Financial Under EWE Sensitivity (Scenario 4 – SWER)

Scenario PVRR (\$, Millions)
(2023 WACC 4.12%)
<u>\$17,275.6315.4</u>

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Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 4 – SWER dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 4 – SWER are \$531,366.

Table 81: Curtailed Intermittent Energy, Annual MWh (Scenario 4 - SWER)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	5,854	0	0	5,854
2027	0	3,378	0	0	3,378
2028	0	2,821	0	0	2,821
2029	0	2,193	0	0	2,193
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	0	14,246	0	0	14,246

Table 82: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 4 - SWER)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	258	4,515	20	1,061
2027	0	3,057	45	276
2028	114	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	0	0	0
RAP Total	372	11,970	87	1,817

The following table reflects PPA pricing, penalties, and taxes.

Table 83: Estimated PPA Curtailment Costs and Penalties, Real (2023) \$ (Scenario 4 - SWER)

	Wind (\$)	Solar (\$)
2024	\$0	\$0
2025	\$0	\$0
2026	\$0	\$216,270
2027	\$0	\$126,321
2028	\$0	\$106,117
2029	\$0	\$82,658
2030	\$0	\$0
2031	\$0	\$0
RAP Total	\$0	\$531,366

Scenario 4 (SWER) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 84: Transmission Interconnection & Network Upgrade Expenses Real (2023) \$ (Scenario 4 - SWER)

Year	Size (MW)	Type	Interconnection Cost (\$M)	Network Upgrade at POI Cost (\$M)	Network Upgrade for Size (\$M)
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		\$2.88	
2034	100	Wind + Battery		\$2.88	
2036	100	Wind + Battery		\$2.88	
2038	100	Wind + Battery		\$2.88	
2042	100	Wind		\$2.88	
2042	100	Wind + Battery		\$2.88	
2042	100	Wind + Battery		\$2.88	

Year	Size (MW)	Type	Interconnection Cost (\$M)	Network Upgrade at POI Cost (\$M)	Network Upgrade for Size (\$M)
Western Colorado (WCO) Transmission Area					
2029	290	Gas	\$1.50	\$4.20	
2043	100	Solar		\$2.88	
2043	100	Solar		\$2.88	
2043	100	Solar		\$1.68	
Wyoming (WYO) Transmission Area					
2040	100	Wind + Battery		\$12.00	\$109.00
2041	100	Wind		\$4.20	
2041	100	Wind		\$4.20	
New Mexico (NM) Transmission Area					
2033	100	Wind		\$2.88	\$238.50
2033	100	Wind + Battery		\$2.88	
2037	100	Wind + Battery		\$2.88	
2043	100	Solar		\$1.68	

Scenario 4 (SWER) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 85: Planning Reserve Margin, % Annual (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	35%	42%	46%	45%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 86: Loss of Load Probability, Hours (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 87: Expected Unserved Energy, Annual MWh (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 4 - SWER)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 4 – SWER, 50 MW of short duration storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 4 (SWER) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 88~~Table 85~~ represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 88: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 4 – SWER)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 89~~Table 86~~ represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 89: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 4 – SWER)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 4 – SWER)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the “analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access.”

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
 - o NM Market HE 2 to HE 6 and HE 11 to 15

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- o 1 day in event no market depth
- Summer:
 - o ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
 - o 1 day in event no market depth

In the EWE analysis for Scenario 4 – SWER, the market was used for 7.3 GWh in 133 hours during the January EWE events between 2026-2031. The market was used for 17 GWh in 99 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

5. Aggressive Colorado Emissions Reductions Scenario (ACER)

Assumptions unique to each scenario are identified in Attachment B-3.^{LKT-10}

Scenario 5 (ACER) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 90: Expansion Plan (Scenario 5 - ACER)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar ¹¹²	West Colorado	140	1	140
2029	Wind/Battery	East Colorado	100	1	100
2030	NGCC with CCS ¹¹³	West Colorado	290	1	290
2031	Wind/Battery	Wyoming / W. Neb.	100	1	100
2033	Wind	East Colorado	100	2	200
2035	Wind/Battery	East Colorado	100	1	100
2037	Wind/Battery	East Colorado	100	1	100
	Wind/Battery	New Mexico	100	2	200
2040	Wind/Battery	Wyoming / W. Neb.	100	2	200
	Solar – Build Transfer	West Colorado	100	2	200
2042	Wind/Battery	East Colorado	100	4	400
	Wind/Battery	Wyoming / W. Neb.	100	3	300
2043	Wind/Battery	Wyoming / W. Neb.	100	1	100
	Solar	New Mexico	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:¹¹⁴

- All plans include applicable Colorado energy efficiency targets in base assumptions.¹¹⁵
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 5 – ACER in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 5 – ACER in 2040.

¹¹² This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.

¹¹³ NGCC installed in 2030 and CCS conversion startup anticipated in 2031.

¹¹⁴ Commission Rule 3605(c)(1)(i).

¹¹⁵ 2020 ERP Settlement Agreement at Section 3.11.6.

The expansion plan also included the following Demand Response (DR) levels by region:¹¹⁶

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.¹¹⁷
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 5 - ACER in 2038
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 5 – ACER starting in 2042.

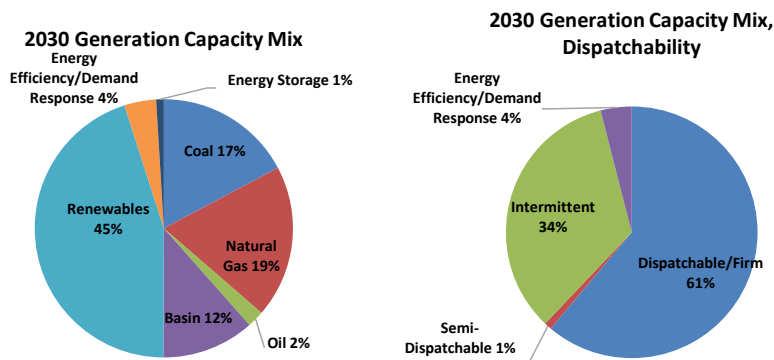
Unit retirements selected in the modeling are shown in the following table.¹¹⁸

Table 91: Modeled Retirements (Scenario 5 - ACER)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037
LRS 2 (TS portion)	241	Coal	1/1/2042

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 8: Projected Tri-State System Resource Mix 2030 (Scenario 5 - ACER)^{119, 120, 121}



¹¹⁶ Commission Rule 3605(c)(1)(I).

¹¹⁷ 2020 ERP Settlement Agreement at Section 3.11.8.

¹¹⁸ Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").

¹¹⁹ "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.

¹²⁰ Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.

¹²¹ System Energy Mix reflects sales to Members and non-Members.

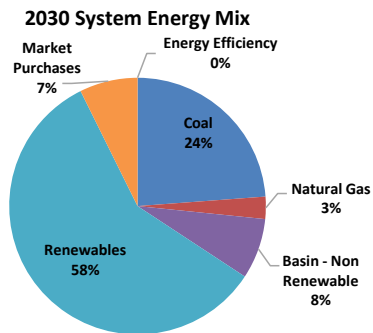


Table 92: Projected Annual Capacity Factors for Thermal Resources (Scenario 5 - ACER)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	16%	0%	0%	0%	0%	0%	0%
Craig 2	98%	9%	17%	4%	9%	0%	0%	0%
Craig 3	79%	14%	15%	11%	0%	0%	0%	0%
LRS 2	93%	89%	86%	78%	75%	71%	69%	69%
LRS 3	75%	64%	55%	48%	43%	40%	40%	45%
SPV 3	72%	67%	43%	42%	42%	36%	44%	43%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	24%	11%	1%	1%	1%	1%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	0%	0%	16%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 93: Forecasted Energy Sales and Purchases (Scenario 5 – ACER)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,508	1,506	2,719	2,521	2,453	2,347	2,911	3,587
Purchases (GWh)	352	946	641	985	803	854	1,020	776

Scenario 5 (ACER) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 94: Environmental Impact - System Wide (Scenario 5 - ACER)¹²²

Year	CO ₂ (ST)	SO ₂ (ST)	NO _x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH ₄ (MT CO ₂ e)
2024	15,841,198	7,764	10,744	0.0383	704	6,774,266,318	32,133
2025	10,919,154	5,447	6,450	0.0245	513	4,099,792,207	19,995
2026 ¹²³	8,046,894	4,781	5,543	0.0211	393	3,336,852,935	16,657
2027	7,524,321	4,471	5,149	0.0187	359	2,957,263,352	15,143
2028	6,758,931	4,045	4,479	0.0164	340	2,603,401,641	13,418
2029	6,279,584	3,827	4,253	0.0150	303	2,351,374,862	12,230
2030	5,720,642	3,969	4,393	0.0154	340	2,617,482,127	13,065
2031	5,621,064	3,993	4,418	0.0159	364	3,205,678,404	13,331
2032	5,229,420	3,827	4,281	0.0147	330	2,990,089,809	12,392
2033	5,542,856	3,963	4,395	0.0157	357	3,162,785,437	13,164
2034	5,600,099	3,999	4,444	0.0158	359	3,185,362,689	13,291
2035	5,341,998	3,895	4,362	0.0153	335	3,057,746,388	12,644
2036	4,976,911	3,771	4,291	0.0144	297	2,858,196,567	11,765
2037	3,872,884	3,313	3,900	0.0123	197	2,353,044,102	8,984
2038	3,889,235	3,328	3,924	0.0123	197	2,350,104,263	9,021
2039	3,958,518	3,372	3,983	0.0125	199	2,378,852,575	9,176
2040	3,928,034	3,352	3,944	0.0125	200	2,381,909,167	9,114
2041	3,954,875	3,371	3,977	0.0125	199	2,380,272,599	9,172
2042	2,550,838	2,573	3,064	0.0065	119	1,575,749,975	6,087
2043	2,537,465	2,577	3,059	0.0065	118	1,562,045,832	6,084
Total	118,094,923	79,640	93,054	0.316	6,224	58,182,271,249	256,864
Pounds/Gallons per MWh ¹²⁴	816	0.55	0.64	0.000002	0.04	201	1.955

¹²² Commission Rule 3605(c)(1)(H). All tons are in short tons (ST), except for CH₄ which is provided as metric tons of carbon dioxide equivalent (MT CO₂e). CO₂, SO₂ and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

¹²³ Load reduced due to partial requirements contracts in 2026 forward.

¹²⁴ Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 95: Social Cost of Carbon Nominal Dollars – System Wide (Scenario S - ACER)

Year	Annual Social Cost of Carbon
2024	\$1,391,188,757
2025	\$995,703,293
2026	\$762,481,386
2027	\$740,668,558
2028	\$690,004,358
2029	\$664,696,921
2030	\$627,713,272
2031	\$639,644,830
2032	\$616,992,472
2033	\$677,908,422
2034	\$709,833,808
2035	\$701,607,194
2036	\$677,161,912
2037	\$545,789,145
2038	\$567,589,551
2039	\$598,133,480
2040	\$614,409,701
2041	\$637,343,954
2042	\$427,991,342
2043	\$439,003,933

Table 96: Social Cost of Methane Nominal Dollars – System Wide (Scenario 5 - ACER)

Year	Annual Social Cost of Methane
2024	\$82,865,100
2025	\$54,041,930
2026	\$47,200,356
2027	\$44,961,643
2028	\$41,658,773
2029	\$39,685,014
2030	\$44,283,639
2031	\$47,333,383
2032	\$46,063,578
2033	\$51,195,405
2034	\$54,050,793
2035	\$53,741,866
2036	\$52,234,099
2037	\$41,644,283
2038	\$43,640,015
2039	\$46,305,451
2040	\$47,955,236
2041	\$50,131,697
2042	\$35,047,588
2043	\$35,786,521

Table 97: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 5 - ACER)

Year	Target ¹²⁵	Forecast
2025	47%	47%
2026	60%	66%
2027	67.8%	73%
2028	74.2%	76%
2029	80.6%	82%
2030	87.1%	88%
2031	90%	91%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 5 (ACER) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

¹²⁵ Modified targets per stakeholder-requested scenario assumptions identified in Attachment B-3, but still meets GHG reduction targets in 2020 ERP Settlement Agreement Sections 3.3.4. and 3.3.5.

LKT-10

Table 98: Total Financial (Scenario 5 - ACER)

\$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	\$17,208.2	\$11,026.8	\$758.1	\$28,235.0	\$28,993.1
Expansion Plan CapEx + IDC: Generation (Nominal \$)	\$1,635.9				
Expansion Plan CapEx + IDC: Transmission (Nominal \$)	\$623.0				

Table 99: Annual Financial (Nominal \$) (Scenario 5 - ACER)

Year	Total Annual Revenue Requirement (\$, Millions)
2024	\$1,016
2025	\$978
2026	\$898
2027	\$960
2028	\$1,007
2029	\$1,075
2030	\$1,212
2031	\$1,232
2032	\$1,400
2033	\$1,415
2034	\$1,452
2035	\$1,474
2036	\$1,506
2037	\$1,447
2038	\$1,470
2039	\$1,501
2040	\$1,523
2041	\$1,537
2042	\$1,554
2043	\$1,730

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

Table 100: Total Financial Under EWE Sensitivity (Scenario 5 – ACER)

Scenario PVRR (\$, Millions)
(2023 WACC 4.12%)
<u>\$17,180.6</u>

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 5 - ACER dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 5 – ACER are \$544,004.

Table 101: Curtailed Intermittent Energy, Annual MWh (Scenario 5 - ACER)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	5,613	0	0	5,613
2027	0	3,345	0	0	3,345
2028	0	2,732	0	0	2,732
2029	0	2,955	0	0	2,955
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	0	14,645	0	0	14,645

Table 102: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 5 - ACER)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	85	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,767	18	170
2030	0	0	0	0
2031	0	0	0	0
RAP Total	110	12,514	98	1,923

The following table reflects PPA pricing, penalties, and taxes.

Table 103: Estimated PPA Curtailment Costs and Penalties, Real (2023) \$ (Scenario 5 - ACER)

	Wind (\$)	Solar (\$)
2024	\$0	\$0
2025	\$0	\$0
2026	\$0	\$207,282
2027	\$0	\$125,001
2028	\$0	\$102,660
2029	\$0	\$109,061
2030	\$0	\$0
2031	\$0	\$0
RAP Total	\$0	\$544,004

Scenario 5 (ACER) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 104: Transmission Interconnection & Network Upgrade Expenses Real (2023) \$ (Scenario 5 - ACER)

Year	Size (MW)	Type	Interconnection Cost (\$M)	Network Upgrade at POI Cost (\$M)	Network Upgrade for Size (\$M)
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind + Battery		\$2.88	
2033	100	Wind		\$2.88	
2033	100	Wind		\$2.88	
2035	100	Wind + Battery		\$2.88	
2037	100	Wind + Battery		\$2.88	
2042	100	Wind + Battery		\$2.88	
2042	100	Wind + Battery		\$2.88	
2042	100	Wind + Battery		\$2.88	
2042	100	Wind + Battery		\$2.88	
Western Colorado (WCO) Transmission Area					
2030	290	Gas	\$1.50	\$4.20	
2040	100	Solar		\$2.88	
2040	100	Solar		\$2.88	
Wyoming (WYO) Transmission Area					
2031	100	Wind + Battery		\$12.00	\$109.00
2040	100	Wind + Battery		\$4.20	
2040	100	Wind + Battery		\$4.20	
2042	100	Wind + Battery		\$4.20	\$34.00
2042	100	Wind + Battery		\$4.20	

Year	Size (MW)	Type	Interconnection Cost (\$M)	Network Upgrade at POI Cost (\$M)	Network Upgrade for Size (\$M)
2042	100	Wind + Battery		\$4.20	
2043	100	Wind + Battery		\$4.20	
New Mexico (NM) Transmission Area					
2037	100	Wind + Battery		\$2.88	\$238.50
2037	100	Wind + Battery		\$2.88	
2043	100	Solar		\$1.68	

Scenario 5 (ACER) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources’ ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 105: Planning Reserve Margin, % Annual (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	35%	31%	44%	47%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 106: Loss of Load Probability, Hours (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
1	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 107: Expected Unserved Energy, Annual MWh (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
2	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 5 - ACER)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario

5 – ACER, 100 MW of 4-hr storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 5 (ACER) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

~~Table 108~~ **Table 104** represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 108: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 5 - ACER)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

~~Table 109~~ **Table 105** represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 109: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 5 - ACER)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

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Tri-State also analyzed the post-RAP period EWE and, Level II metrics were not met in the latter part of the RAP for Scenario 5 – ACER. Scenario 5 – ACER did not meet Level 2 reliability metric thresholds:

- Six hours of LOLH in 2037 (which is beyond the three hours per year threshold); and
- Two hours of capacity lean on the market (which is beyond the zero-tolerance threshold), in the following hours and capacity amounts:
 - o July 12, 2042 HE2, 40 MW; and
 - o July 13, 2043 HE2, 29 MW.

Analysis of Market Purchases and Available Capacity (Scenario 5 – ACER)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the “analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access.”

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
 - o NM Market HE 2 to HE 6 and HE 11 to 15
 - o 1 day in event no market depth

- Summer:
 - o ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
 - o 1 day in event no market depth

In the EWE analysis for Scenario 5 – ACER, the market was used for 6.4 GWh in 115 hours during the January EWE events between 2026-2031. The market was used for 12.5 GWh in 78 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

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Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase I scenarios is provided below.

Environmental Analysis

The following tables identify each scenario's system-wide forecasted CO₂ and CH₄ emissions in 2025 and 2030.

Figure 9: Comparison of Forecasted CO₂ Emissions in 2025 and 2030, by Scenario

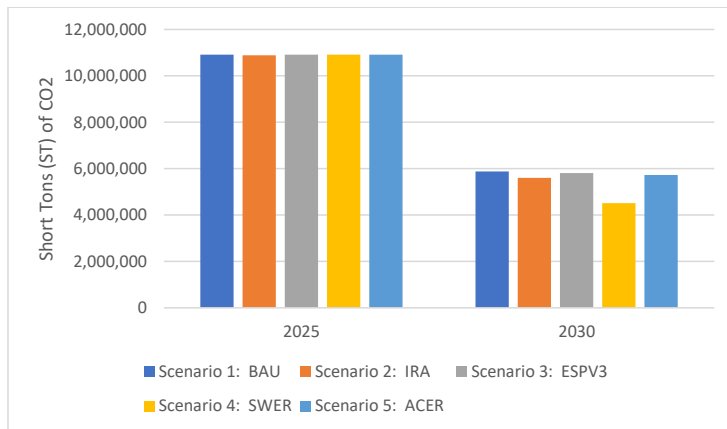
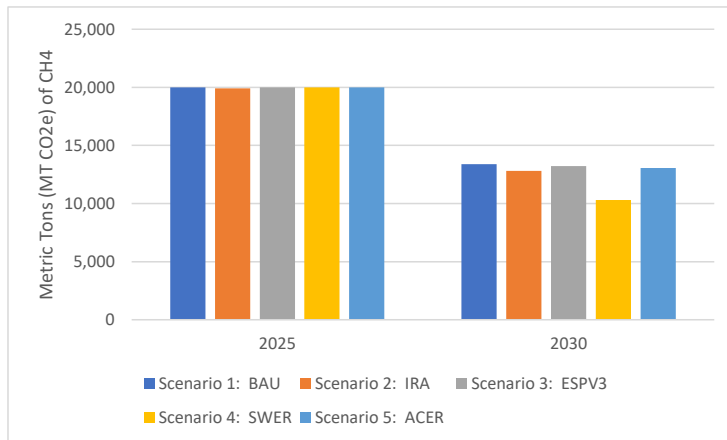


Figure 10: Comparison of Forecasted CH₄ Emissions in 2025 and 2030, by Scenario



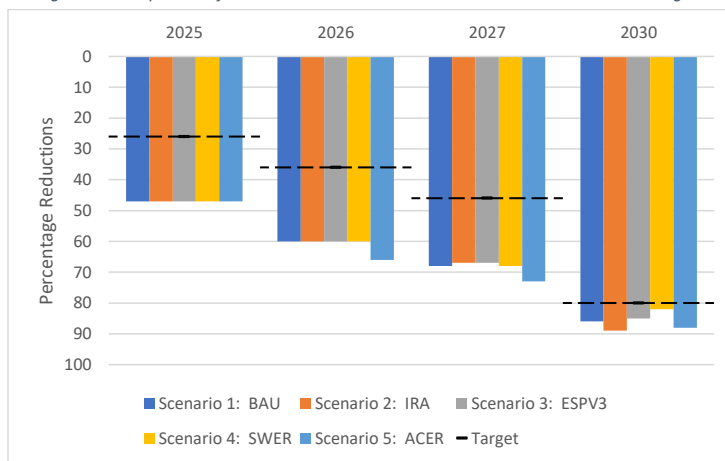
The following table identifies each scenario's forecasted achievements toward Colorado GHG reduction targets. As shown in Figure 9 and ~~Table 110~~ ~~Table 106~~, all scenarios achieve a consistent level of CO₂ and GHG reductions in 2025. The trend of similar GHG reductions across all scenarios holds for 2026 and 2027 as well, with the exception of Scenario 5 (ACER) achieving slightly higher reductions earlier—a result of the underlying modeling input constraint requiring minimum emissions achievements for each year of the RAP (see Attachment ~~B-3~~ ~~LKT-10~~ of the ERP Report (LKT-1)). Those underlying constraints on emissions for Scenario 5 (ACER) result in significant reductions in the capacity factors for Craig 2 and LRS 3 starting in 2026 and result in the new gas plant not being utilized until 2030. Market sales are also reduced during the RAP under Scenario 5 (ACER). Notably, Scenario 2 (IRA), achieves the highest GHG reduction by 2030, 89%, as compared to the other scenarios as show in ~~Table 110~~ ~~Table 106~~ and Figure 11.

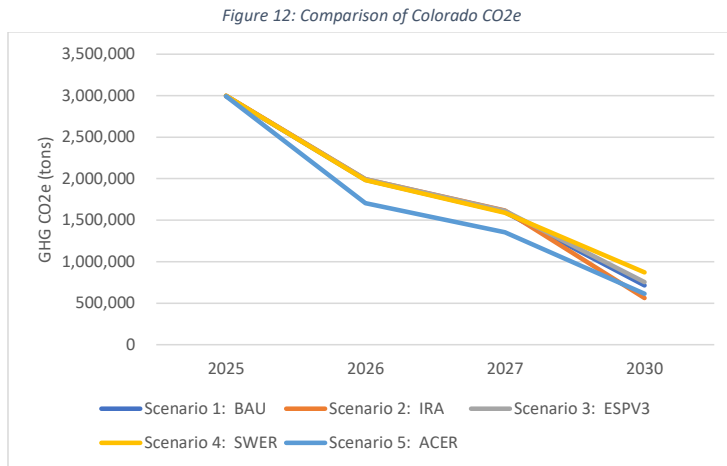
Additional discussion of Tri-State's consideration of the environmental results of the scenario analyses can be found in the Executive Summary; and in the Financial Analysis section below, which scenario identifies PVRs with SCoC and SCoM.

Table 110: Comparison of Scenario Achievements Toward Colorado GHG Reduction Targets

	2025	2026	2027	2030
Scenario 1: BAU	47%	60%	68%	86%
Scenario 2: IRA	47%	60%	67%	89%
Scenario 3: ESPV3	47%	60%	67%	85%
Scenario 4: SWER	47%	60%	68%	82%
Scenario 5: ACER	47%	66%	73%	88%

Figure 11: Comparison of Scenario Achievements Toward Colorado GHG Reduction Targets





As shown in Figure 13 below, there is little deviation in the annual SCoC across the scenarios modeled, until after 2030. Scenario 1 (BAU) and Scenario 5 (ACER) have fairly similar SCoC levels in the early 2030s as Colorado greenhouse gas reduction levels are similar (roughly a 2 percent difference) in 2030; and from 2024 to 2033 the primary differences between the two scenarios being the timing of new resource additions. Neither Scenario 1 (BAU) or Scenario 5 (ACER) retires SPV 3 in the first ten years of the RPP. Scenario 2 (IRA) achieves a lower SCoC due to more renewable resources being added during the RAP, as well as the early retirement of SPV3. Scenario 3 (ESPV3) also results in lower levels of SCoC due to retirement of SPV 3 during the RAP. Scenario 4 (SWER) sets minimum system-wide emission reductions as underlying modeling input constraints, which result in the lowest SCoC levels across the scenarios. Similar trends across the scenarios are seen in Figure 14 below, for SCoM.

Figure 13: Comparison of SCoC

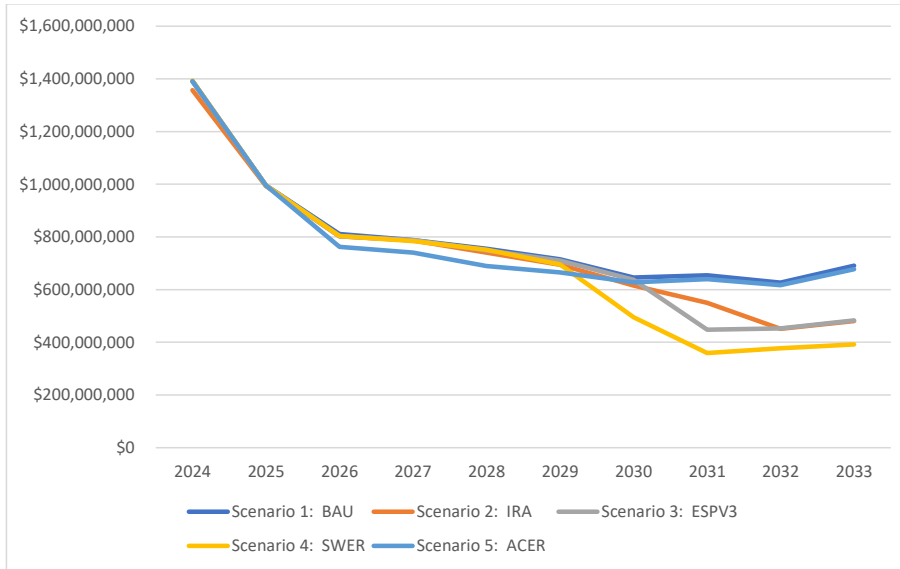
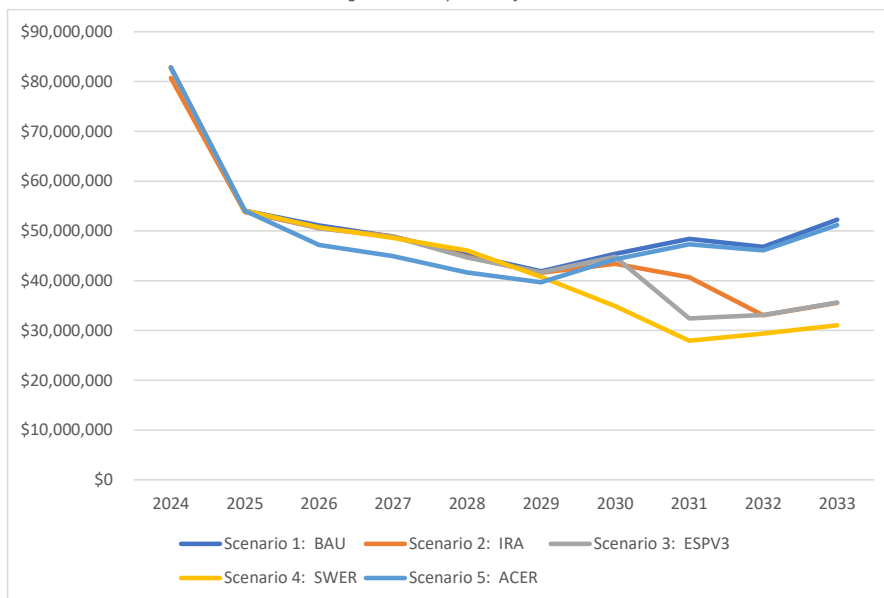


Figure 14: Comparison of SCoM



Financial Analysis

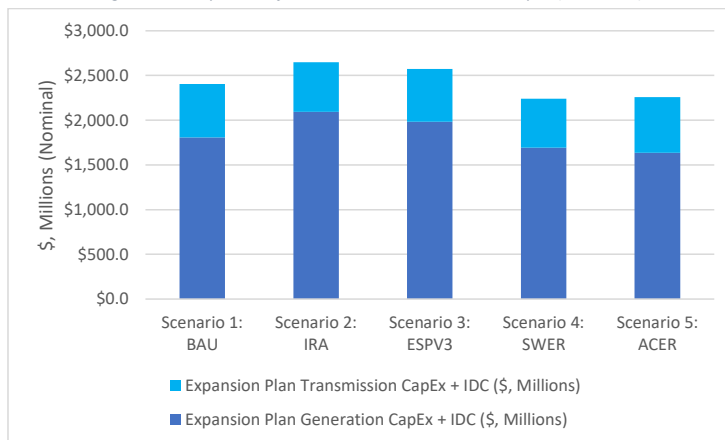
The following table compares total financial results for each scenario, both with and without the SCoC and SCoM. Scenario 2 (IRA) is one of the lowest cost plans on a PVRR basis, and has the lowest renewable curtailment costs during the RAP. ~~Scenario 2 (IRA) also has the lowest PVRR when SCoC and SCoM are included.~~ Scenario 2 (IRA) exceeds Colorado GHG reduction target for 2030, while maintaining reliability and affordability—which best serves Tri-State Members.

Table ~~111411407~~: Comparison of PVRR

	PVRR (\$, Millions)	PVRR w/SCoC and SCoM (\$, Millions)
Scenario 1: BAU	\$17,507.4	\$29,916.4
Scenario 2: IRA	~~\$17,221.35~~ <u>\$17,221.35</u>	~~\$28,688.12~~ <u>\$28,688.12</u>
Scenario 3: ESPV3	\$17,304.2	\$28,828.6
Scenario 4: SWER	\$17,343.9	\$27,922.2
Scenario 5: ACER	\$17,208.2	\$28,993.1

Figure 15 below compares capital expenditures for resource additions and transmission interconnection and upgrades by scenario over the RPP. While the Scenario 2 (IRA) results in comparatively higher CapEx, the overall financial impact of the scenario is the lowest due to New ERA funding being pursued by Tri-State for the benefit of its Members.

Figure 15: Comparison of Generation and Transmission CapEx (Nominal \$)



As shown in ~~Table 112~~ ~~Table 108~~ below, all scenarios selected a 290 MW gas plant during the RAP (in 2028, 2029, or 2030), with conversion to CCS in 2031, and selected some amount of wind hybrids. All scenarios include 140 MW of solar to replace the Coyote Gulch PPA that was terminated in 2023. Scenario 1 (BAU)

and Scenario 3 (ESPV3) have similar levels of MWs and resource additions during the RAP. Scenario 4 (SWER) and Scenario 5 (ACER) have similar levels of MWs and resource additions. Scenario 2 (IRA) selects 1,400 MW of resources during the RAP, in addition to the 140 MW of replacement solar, more than double the total resource additions in Scenario 4 (SWER) and Scenario 5 (ACER) and significantly higher than the total resource additions in Scenario 1 (BAU) and Scenario 3 (ESPV3). The increase in resource selection during the RAP in Scenario 2 (IRA) is due to potential federal funding being available only through the RAP period. The funding would allow Scenario 2 (IRA) to bring on more resources during the RAP while improving affordability, maintaining reliability, and making strides toward evolving environmental requirements.

Table 112: Comparison of MW Additions by Scenario, by Technology over the RAP

	Scenario 1 – BAU	Scenario 2 – IRA	Scenario 3 – ESPV3	Scenario 4 – SWER	Scenario 5 – ACER
Wind	0	500	0	0	0
Solar	140	240	140	140	140
Standalone Storage	100	210	200	0	0
Gas	290	290	290	290	290
Wind Hybrid	300	200	300	100	200
Wind Hybrid – Battery Storage Component	150	100	150	50	100
RAP Total	980	1,540	1,080	580	730

Note: Wind Hybrid components share interconnect.

Table 113 below identifies the percentage of generation capacity that is intermittent or dispatchable/firm, and the percent of system energy that is renewable for each scenario in 2030. Scenario 2 (IRA) yields the highest percentage of renewables in terms of system energy mix in 2030, while maintaining a reasonable mix of intermittent and dispatchable/firm capacity at 39 percent and 54 percent, respectively.

Table 113: Comparison of Renewables, Intermittent and Dispatchable Resources in the 2030 Mix, by Scenario

	2030 Generation Capacity Mix, % Intermittent	2030 Generation Capacity Mix, % Dispatchable/Firm	2030 System Energy Mix, % Renewables
Scenario 1: BAU	34%	59%	59%
Scenario 2: IRA	39%	54%	64%
Scenario 3: ESPV3	34%	61%	58%
Scenario 4: SWER	33%	61%	61%
Scenario 5: ACER	34%	61%	58%

Note: Capacity from energy efficiency / demand response and semi-dispatchable resources are not reflected in either the intermittent or dispatchable/firm, therefore the sum of the capacity mix percentages does not total 100%.

Curtailments

The following tables identify the annual PPA curtailment costs (pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type.

Table 114: Comparison of Wind PPA Curtailment Costs by Scenario, Real (2023) \$

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
2024	\$0	\$0	\$0	\$0	\$0
2025	\$0	\$0	\$0	\$0	\$0
2026	\$0	\$0	\$0	\$0	\$0
2027	\$0	\$0	\$0	\$0	\$0
2028	\$0	\$0	\$0	\$0	\$0
2029	\$0	\$0	\$0	\$0	\$0
2030	\$0	\$0	\$0	\$0	\$0
2031	\$0	\$8,765	\$2,511	\$0	\$0
RAP Total	\$0	\$8,765	\$2,511	\$0	\$0

Table 115: Comparison of Solar PPA Curtailment Costs by Scenario, Real (2023) \$

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
2024	\$0	\$0	\$0	\$0	\$0
2025	\$0	\$0	\$0	\$0	\$0
2026	\$208,078	\$2,816	\$208,309	\$216,270	\$207,282
2027	\$125,060	\$0	\$124,914	\$126,321	\$125,001
2028	\$102,674	\$9,596	\$102,651	\$106,117	\$102,660
2029	\$82,738	\$122,947	\$82,570	\$82,658	\$109,061
2030	\$0	\$29,692	\$0	\$0	\$0
2031	\$0	\$329,902	\$0	\$0	\$0
RAP Total	\$518,550	\$494,953	\$518,444	\$531,366	\$544,004

Scenario 4 (SWER) and Scenario 5 (ACER) have the highest curtailment costs compared to the other scenarios. Scenario 2 (IRA) has the lowest curtailment costs while still achieving the highest GHG reduction in Colorado by 2030.

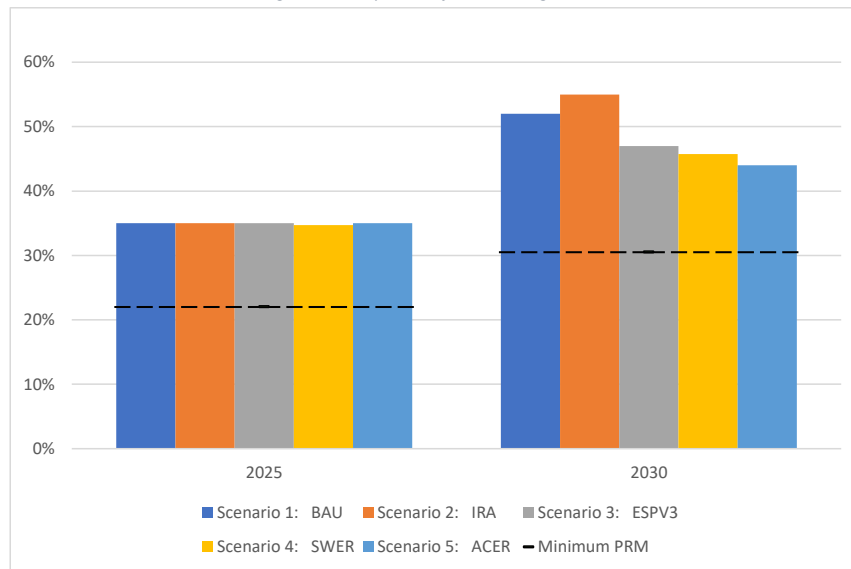
Table 116: Comparison of Total Wind + Solar Curtailment Costs during the RAP, by Scenario, Real (2023) \$

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
RAP Total	\$518,550	\$503,718	\$520,955	\$531,366	\$544,004

Reliability Analysis

PRMs were relatively consistent across all scenarios through 2027. PRMs in 2030 range from 44 percent to 55 percent. The level of resource additions enabled by potential New ERA funding in Scenario 2 (IRA) resulted in higher PRMs during the RAP as compared to other scenarios.

Figure 16: Comparison of PRMs During the RAP



Each of the scenarios were able to meet Level I and II reliability metrics during the RAP. Scenario 2 (IRA) is the scenario that results in the greatest certainty in achieving reliability in the most cost-effective manner because it allows for the acquisition of more resources earlier in Tri-State's planning period. Tri-State's PRMs stay well above requirements, allowing for potential procurement or operational delays to more likely be addressed without reliability issues.

Conclusion

Given the comprehensive and thorough data obtained on the multiple scenarios modeled, the ERP Report supports approval of the IRA Scenario as Tri-State's preferred plan. As such, Tri-State requests the Commission: (1) find that the IRA Scenario within Tri-State's ERP Application meets the applicable rule requirements, (2) approve the IRA Scenario as Tri-State's Phase I preferred plan, and (3) approve Tri-State's Phase II procurement plans in this proceeding.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-21
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit XX: Department, Order No. 202-26-16 (Feb. 17, 2026)



Department of Energy
Washington, DC 20585

Order No. 202-26-16

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, Michigan. In 2021, Consumers announced that it planned to implement a “speed closure” of the Campbell Plant fifteen years before the end of its scheduled design life.³ Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant’s retirement and discontinue its operations on May 31, 2025.

Order Nos. 202-25-3 and 202-25-7, issued pursuant to FPA section 202(c), each required that the Campbell Plant remain in operation for 90 days, until August 21, 2025, and November 19, 2025, respectively. Subsequently, Order No. 202-25-9, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until February 17, 2026. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO likely faced tight reserve margins due to well documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.⁴ I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods, which would help

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ See Consumers Energy, *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan’s Clean Energy Transformation* (June 23, 2021), <https://www.consumersenergy.com/news-releases/newsrelease-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-cleanenergy-transformation>.

⁴ See, e.g., *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-9, at 3-7 (Nov. 18, 2025).

prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.⁵ I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability.⁶ My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC stated that “[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.”⁷ In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.⁸

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), “[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned.”⁹ Additionally, EIA stated, “[t]ypically, Michigan’s nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned.”¹⁰ The state’s Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although according to a recent news report, “Holtec International expects the Palisades plant in Michigan to resume service early next year”¹¹

Third, the Campbell Plant’s retirement would have further decreased available dispatchable generation within MISO’s service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant

⁵ See, e.g., *Id.* at 7-8.

⁶ See, e.g., *Id.* at 8.

⁷ NERC, *2025 Summer Reliability Assessment*, at 16 (May 2025) (NERC 2025 Summer Reliability Assessment), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

⁸ *Id.*

⁹ EIA, *Michigan State Profile and Energy Estimates* (Oct. 17, 2024), <https://www.eia.gov/state/print.php?sid=MI>.

¹⁰ *Id.*

¹¹ L.A. TIMES, *Nuclear plants face decadelong timeline to meet AI energy needs* (Nov. 13, 2025), <https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs>.

into their supply forecasts, and Consumers acquired a 1,200 MW natural gas power plant in Covert, Michigan, NERC still anticipates “elevated risk of operating reserve shortfalls.”¹²

Fourth, MISO’s Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.”¹³ While the results “demonstrated sufficient capacity,” the summer months reflected the “highest risk and a tighter supply-demand balance.”¹⁴ According to MISO, these results “reinforce the need to increase capacity.”¹⁵

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-3, 202-25-7, and 202-25-9 continue, both in the near and long term.¹⁶ The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the U.S. Environmental Protection Agency’s data, from June 2025 through December 2025,¹⁷ the Campbell plant has generated an average of approximately 561,100 MWh per month, providing vital generation capacity to the region. From June 11, 2025 through November 5, 2025, MISO issued dozens of alerts to manage grid reliability in its Central Region in response

¹² NERC 2025 Summer Reliability Assessment at 16.

¹³ MISO, *Planning Resource Auction—Results for Planning Year 2025–2026*, at 13 (May 29, 2025) (MISO 2025– 2026 Planning Resource Auction), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

¹⁴ *Id.* at 12.

¹⁵ *Id.* at 2. For further information regarding the determination that emergency conditions existed, see *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-7 (Aug. 20, 2025).

¹⁶ Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. See Order No. 202-25-7 at 1, n.1.

¹⁷ See, *Custom Data Download, EPA CAMPD (Clean Air Markets Program Data)*, <https://campd.epa.gov/data/custom-data-download> (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >> Apply >> “2025” and “June, July, August, September, October, November, December.” The data can then be filtered to only include the J.H. Campbell Plant.).

to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.

MISO's year-round resource adequacy concerns are well documented. In 2021, MISO requested that the Federal Energy Regulatory Commission (FERC) approve its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.¹⁸ MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."¹⁹ MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.²⁰

In December of 2023, MISO released its *Attributes Roadmap*, in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."²¹ Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023–2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons.²² MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.²³

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *MISO's Response to the Reliability Imperative*.²⁴ In a section of that report labeled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

¹⁸ MISO, *Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct*, FERC Docket No. ER22-495-000 (Nov. 30, 2021) (MISO Transmittal Letter). This request was approved by FERC on August 31, 2022. See *Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

¹⁹ MISO Transmittal Letter at 3.

²⁰ *Id.* at 3-4.

²¹ MISO, *Attributes Roadmap* (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>.

²² *Id.* at 11.

²³ *Id.*

²⁴ MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>.

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.²⁵

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.²⁶ NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,²⁷ stating that it faces significant reliability challenges as “projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements.”²⁸ This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.²⁹ The 2025 NERC Long-Term Reliability Assessment notes that “MISO’s accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements.”³⁰ The report observes that winter peak periods are a particular concern, with projections showing “shortfalls in planned resources for winter peak periods.”³¹ However, NERC also concluded that “risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high.”³²

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the “[p]otential for insufficient operating reserves in above-normal conditions.”³³ These findings were echoed in NERC’s 2024 – 2025 Winter Reliability Assessment, which noted that “[g]enerating capacity is 10 GW lower (-6.8%) compared to the

²⁵ *Id.* at 12.

²⁶ NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026) (2025 NERC Long-Term Reliability Assessment), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

²⁷ *Id.* at 7.

²⁸ *Id.* at 8.

²⁹ *Id.* at 43.

³⁰ *Id.* at 15.

³¹ *Id.*

³² *Id.*

³³ NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

prior winter as generators have retired, withdrawn from MISO’s capacity market, or received lower winter accredited capacity.”³⁴

MISO’s resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when it operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 event for MISO’s North and Central Regions due to generational outages, high demand, and transfer capability limits.³⁵

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–2026 Planning Year, it noted that “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Michigan.³⁶

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.³⁷ The 2025 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.³⁸ The 2025 OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.³⁹ Similar results were projected for MISO’s winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.⁴⁰

³⁴ NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

³⁵ See MISO Notifications Overview, *Real-Time Operations*, <https://www.misoenergy.org/markets-and-operations/notifications/>.

³⁶ MISO 2025 – 2026 Planning Resource Auction at 13.

³⁷ OMS & MISO, *OMS-MISO Survey Results* (updated June 6, 2025) (2025 OMS-MISO Survey), <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

³⁸ *Id.* at 2.

³⁹ *Id.* at 7.

⁴⁰ *Id.* at 9.

The primary reasons for these projected deficits also are shown on the 2025 OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.⁴¹ Although the 2025 OMS-MISO Survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.⁴²

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025,⁴³ and the ERAS should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.⁴⁴ In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.⁴⁵ Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3, 202-25-7, and 202-25-9 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary

⁴¹ *Id.* at 7, 9.

⁴² *Id.*

⁴³ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

⁴⁴ *Id.* P 84.

⁴⁵ See generally S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), <https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply>. “With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts.”

threat to our Nation’s economy, national security, and foreign policy.”⁴⁶ The Executive Order adds, “hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”⁴⁷ In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”⁴⁸

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”⁴⁹ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.⁵⁰ In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and “continue[s] to see positive momentum with data centers within the 9 GW pipeline”⁵¹

⁴⁶ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

⁴⁷ *Id.*

⁴⁸ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

⁴⁹ U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

⁵⁰ Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan* (last accessed Aug. 13, 2025), <https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan>.

⁵¹ See Data Center Dynamics, *Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center* (Aug. 5, 2025) (quoting Consumers CEO Garrick Rochow), <https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/>.

Grid operators — including MISO itself — have also acknowledged the Nation’s current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that “the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth.”⁵² Ms. Curran also described “much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence.”⁵³ She added, “[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them.”⁵⁴

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”⁵⁵ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

⁵² *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcommittee on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-mediadocument/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

⁵³ *Id.* at 6.

⁵⁴ *Id.* at 7.

⁵⁵ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from the combination of increasing demand for electricity and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3, 202-25-7, and 202-25-9, will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand for electricity and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

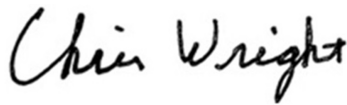
To ensure that the Campbell Plant will be available if needed to address emergency conditions, it shall remain in operation until May 18, 2026.⁵⁶

Based on my determination of an emergency set forth above, I hereby order:

- A. From February 17, 2026, MISO and Consumers shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.
- C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.
- D. By March 4, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

⁵⁶ 16 U.S.C. § 824a(c)(4).

- E. Consumers is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.
- H. This Order shall be effective on February 17, 2026, through May 18, 2026, with the exception of applicable compliance obligations in paragraph D.



Chris Wright
Secretary of Energy

cc:

FERC Commissioners

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Michigan Public Service Commissioners

Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Craig Unit 1	)	Order No. 202-26-21
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit Y: CoPUC, *Verified Petition of Trial Staff of the Commission, CEO, UCA, and Public Service for a Variance from Decision No. C18-0761 and Any Other Requirements, Request for Shortened Notice and Intervention Period, and Request for Approval of Associated Procedures*, filed on November 10, 2025,
in Proceeding No. 25V-0480E

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

IN THE MATTER OF THE VERIFIED)
PETITION OF TRIAL STAFF OF THE)
COMMISSION, THE COLORADO)
ENERGY OFFICE, THE COLORADO)
OFFICE OF THE UTILITY CONSUMER)
ADVOCATE, AND PUBLIC SERVICE)
COMPANY OF COLORADO)
FOR A VARIANCE FROM ORDERING)
PARAGRAPHS 1 AND 2 OF DECISION)
NO. C18-0761 AND ANY OTHER)
REQUIREMENTS)
)

PROCEEDING NO. 25V-____E

**VERIFIED PETITION OF TRIAL STAFF OF THE COMMISSION, THE COLORADO
ENERGY OFFICE, THE COLORADO OFFICE OF THE UTILITY CONSUMER
ADVOCATE, AND PUBLIC SERVICE COMPANY OF COLORADO
FOR A VARIANCE FROM DECISION NO. C18-0761 AND ANY OTHER
REQUIREMENTS, REQUEST FOR A SHORTENED NOTICE AND INTERVENTION
PERIOD, AND REQUEST FOR APPROVAL OF ASSOCIATED PROCEDURES**

Pursuant to Rules 1003 and 1304(e) of the Colorado Public Utilities Commission’s (“Commission”) Rules of Practice and Procedure, Trial Staff of the Colorado Public Utilities Commission (“Staff”), the Colorado Energy Office (“CEO”), the Colorado Office of the Utility Consumer Advocate (“UCA”), and Public Service Company of Colorado (“Public Service” or the “Company”) (collectively, the “Joint Petitioners”) seek a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761, and any other decisions the Colorado Public Utilities Commission (“Commission”) deems necessary, to modify the plan to retire Comanche Unit 2 from December 31, 2025, to December 31, 2026. Good cause exists to grant the variance, and the limited modification of the planned Comanche Unit 2 retirement date is in the public interest.

Electric resource planning (“ERP”) proceedings have assumed the retirement of Comanche Unit 2 at year-end 2025 for several years dating back to 2018 when the Commission issued Decision No. C18-0761. The ensuing years have brought numerous changes in state policy, federal policy, resource planning, and power procurement. And, over that same timeframe, we have seen increasing peak load growth, requiring incremental resources to serve this demand. Most recently, supply chain challenges, tariff uncertainties, and changes to federal law have led to delayed in-servicing of resources that could have helped address this challenge, ultimately affecting Public Service’s loads and resources projections. In addition, the Company has updated its resource accreditation and planning reserve margin development approaches based on industry best practices and resulting greater than anticipated resource needs.

A variance to the requirement to file an application to amend the Certificate of Public Convenience and Necessity (“CPCN”) for Comanche Unit 2 and a one year extension of the plan to retire Comanche Unit 2 to December 31, 2026 is appropriate at this time and keeps the unit available to Public Service system operators in 2026. The Joint Petitioners believe that the continued operation of Comanche Unit 2 in 2026 is the most cost-effective approach to providing needed electricity for the system (as shown in the Company’s loads and resources projections for summer 2026 in resource planning filings). Importantly, this Petition does not seek an order allowing for the operation of Comanche Unit 2 in perpetuity—it seeks a modest extension in the plan to retire the unit while setting up a process that will assess both resource options and mechanisms to continue orderly progress towards the State of Colorado’s 2030 emissions reduction objectives.

To facilitate the timely resolution of the variance sought through this Petition, the Joint Petitioners request a shortened notice and intervention period of ten (10) days pursuant to Rule

1003(b), along with associated procedures set forth in this Petition. At this time, the Joint Petitioners are not requesting any further modification of existing resource plans beyond the variance requested here to address recent events and associated issues discussed in this Petition.

I. OVERVIEW

The orderly transition of coal-fired generation resources has been a centerpiece of Colorado resource planning for over a decade. In Public Service’s 2016 ERP, Proceeding No. 16A-0396E, parties reached a settlement requiring the Company to propose portfolios in which Comanche Units 1 and 2 would retire early. The Commission approved that settlement, and Public Service then presented portfolios showing that retiring Comanche Units 1 and 2 in 2022 and 2025, respectively, would result in no additional cost to customers relative to portfolios in which the units retired in later years. The Commission-approved portfolio in Proceeding No. 16A-0396E resulted in a portfolio of resources to replace portions of the energy and capacity from Comanche Units 1 and 2. The Commission subsequently approved an accelerated depreciation and cost recovery schedule for Comanche Units 1 and 2 in Proceeding No. 17A-0797E.

In the Company’s next resource plan, the 2021 ERP and Clean Energy Plan (“2021 ERP & CEP”), Proceeding No. 21A-0141E, modeling assumed that Comanche Unit 2 would retire on December 31, 2025. Numerous parties to the proceeding reached an Updated Non-Unanimous Partial Settlement Agreement (“USA”) with Comanche Unit 3 retiring by January 1, 2031. The parties to the USA included a diverse set of parties, including the Joint Petitioners. The Commission approved the USA, and subsequently approved a portfolio of resources in Proceeding No. 21A-0141E based on modeling and analyses assuming that Comanche Unit 2 would retire on December 31, 2025.

These plans were reasonable and appropriate based on the information available at the time they were created and approved by the Commission. Recent events have resulted in challenges to those plans that generally fall into four areas: (1) the impact of the extended outage of Comanche Unit 3 on the Public Service system; (2) increasing peak load growth in the Public Service territory; (3) supply chain and geopolitical/macroeconomic impacts; and (4) reassessment of resource accreditation and planning reserve margin methodologies. While the Commission has multiple planning and other regulatory processes that are available to manage and address these issues, each of these issues layers atop one another, contributing to the need for the variance presented here.

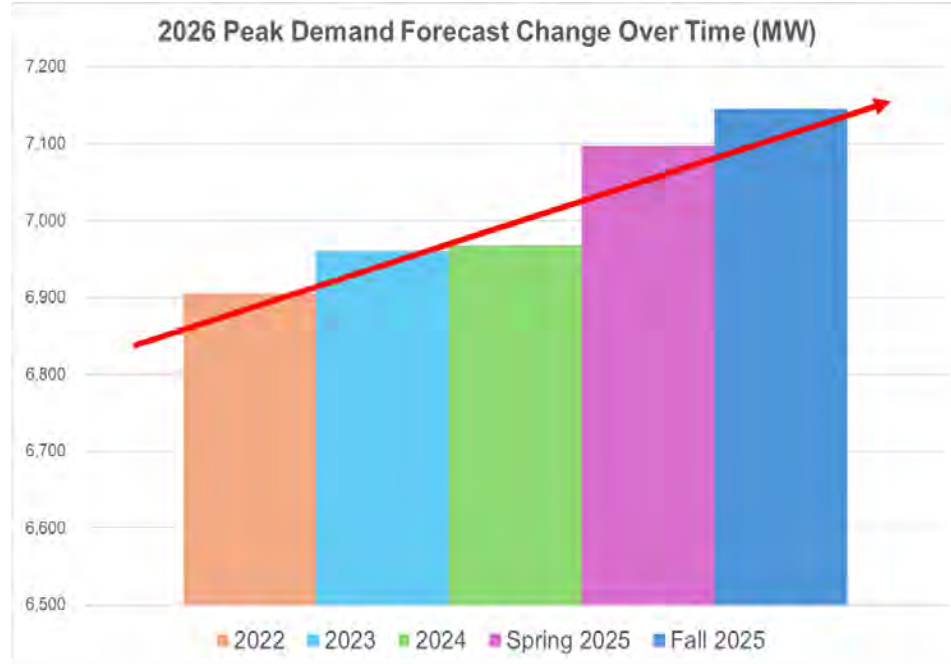
A. Comanche Unit 3 Outage and the Need for Comanche Unit 2 in 2026

Comanche Unit 3, which provides Public Service's system with 415 MW of accredited capacity, experienced an unplanned outage and is offline through at least June 2026. This outage, combined with the other layered issues described below, i.e., supply chain and geopolitical issues, and increasing peak demand, leads to this proposal to operate Comanche Unit 2 (which has a nameplate capacity of 335 MW and an accredited capacity of 296 MW) as a cost effective, near-term solution and supports the need for the requested variance. The Joint Petitioners propose a process below for a future report and application; the extension of Comanche Unit 2 facilitates time for that reporting and review to occur.

B. Increasing Peak Demand in Public Service Territory

Figure 1 below shows the peak demand forecast for summer of 2026 over time in megawatts ("MWs") year-over-year from forecasts developed in 2022 through the fall of this year. Each updated forecast illustrates the growing peak demand on the Company's system, reflective of the load growth forecasted by Public Service and focused on the year 2026.

Figure 1: Peak Demand Forecast Over Time (2022-2025) for Year 2026



C. Supply Chain and Geopolitical Issues

Supply chain and geopolitical issues also contribute to the challenge, impacting the viability of projects in various ways. The Company addressed this in the CEP Delivery Plan in September 2024 (also in Proceeding No. 21A-0141E). The Commission issued a final decision approving the CEP Delivery Plan parameters on January 14, 2025. In approving the CEP Delivery Plan with modifications, the Commission stated:

Our Decision allows the generation and storage projects included within the CEP to continue advancing despite changing market dynamics and geopolitical uncertainties, including importantly potential future changes in federal law. Advancing these generation and storage projects as part of the overall determinations made through the course of this Proceeding moves Colorado forward towards achieving aggressive state emission reduction targets.¹

The CEP Delivery Plan and associated evidentiary record illustrates the supply chain and geopolitical challenges that utilities and developers are navigating, along with the State of

¹ Decision No. C25-0024, at ¶ 2 (Jan. 14, 2025).

Colorado’s response to them. While the CEP Delivery Plan assists with navigating these issues, it does not cure them.

D. Resource Accreditation and Planning Reserve Margin Changes

In accordance with the USA, the Company worked with an industry-leading consultant in the ongoing Just Transition Solicitation (“JTS”) in Proceeding No. 24A-0442E to update its method for determining accredited capacity in a way that was more accurate and aligned with industry best practices.² That analysis revealed additional energy and capacity needs compared to prior modeling approaches. As such, the Company’s need for resources—including in 2026 and 2027—identified through electric resource planning processes has increased over the coming years. The Commission continues to address overall energy and capacity needs through on-going planning proceedings, including the Near-Term Procurement (“NTP”), an innovative multi-stage electric resource plan solicitation, and other planning proceedings. However, just like the supply chain and geopolitical impacts on resource development and in-servicing, the updated accreditation and planning reserve margin approach affects the Company’s loads and resources balance.

E. Next Steps

The Comanche Unit 3 development brought the Joint Petitioners together in requesting a variance to extend the planned retirement date of Comanche Unit 2. But simply obtaining a variance here is not the end of the work. Indeed, the variance sought through this Petition creates

² See, e.g., Hrg. Ex. 102, Direct Testimony of Jon T. Landrum, at 30:12-20 (explaining that consultant Energy and Environmental Economics, Inc. (“E3”) utilized their Renewable Energy Capacity Planning Model (RECAP), which is a loss of load probability model used to evaluate the resource adequacy of electric power systems. E3 originally developed RECAP in 2011 for the California Independent System Operator (“CAISO”) and has since adapted the model for other Independent System Operators, including MISO, PJM, NYISO, and ISO-NE; utilities, including Duke Energy, the Sacramento Municipal Utilities District, Portland General Electric, Puget Sound Energy, Dominion Energy, Salt River Project, Public Service of New Mexico, and New Brunswick Power; and public utilities commissions, including the Oregon and Texas PUCs.”).

an appropriate period of time to assess more permanent, long-term options, including resources that are projected to come on-line through on-going resource planning and other processes and consideration of updated retirement dates for Comanche Unit 2 and Comanche Unit 3. These efforts will include assessments of resource “portfolio” options for near-term, mid-term, and more permanent resource adequacy solutions, paired with emissions assessments of different approaches.

The Joint Petitioners propose two updates to the Commission on work in the extended review period in two different steps, as follows:

Step 1: March 1, 2026 Report. The Company will provide a report to the Commission on or before March 1, 2026. This report will include an update on the repair and return to service status of Comanche Unit 3, including forecasted cost of repairs, any resource options identified in collaborative work with the Joint Petitioners for potential near-term resource adequacy benefits, and other analysis relevant to the four areas outlined above. It will also include an initial plan to address on-going needs considering all available options, including not only plant extensions, but also expedited resource additions and demand-side options, with further refinement in Step 2. In addition, the Joint Petitioners intend to discuss the operations of Comanche Unit 2 over the course of the first quarter to determine appropriate operational parameters or approaches that may work for the unit while it operates in 2026, with a specific focus on operations after Comanche Unit 3 returns to service. The Step 1 report would include the results or status of these operations-focused discussions among the Joint Petitioners to keep the Commission apprised of potential options under consideration or options that the Company is comfortable pursuing.

Step 2: June 1, 2026 Application. For the second step, the Company commits to file an application for any additional variances or resource approvals, building on the Step 1 report and

depending on options identified through the collaborative work with the Joint Petitioners in the review period, by June 1, 2026. As part of that filing, the Company will include updated loads and resources tables and loss of load calculations that include analysis of new resources projected to come on-line from the NTP, JTS Phase II resource solicitation (in Proceeding No. 24A-0442E and to the extent known), or other relevant proceedings. The Company would likely seek consideration of any such requests on an expedited basis, e.g., a 120-day schedule. Options proposed for approval will focus on intermediate and long-term contracts, generation resource acquisitions, generation resource development, new distributed energy resource opportunities, potential demand response or programming changes beyond currently-approved program limits, or any other options that can benefit the Company's near- or mid-term resource adequacy position on either a temporary (e.g., a few years) or more permanent basis.³

These two steps make use of the extended review period with appropriate check-ins with the Commission. Moreover, and equally important, they set out an orderly process of next steps as the Company, in collaboration with the other Joint Petitioners, assesses the future operation of Comanche Unit 2, Comanche Unit 3, and other resource options.

II. REQUEST FOR VARIANCE

Rule 1003(c) sets forth the requirements for a variance petition:

- (I) citation to the specific paragraph of the rule or decision from which the waiver or variance is sought;
- (II) a statement of the waiver or variance requested;
- (III) a statement of facts and circumstances relied upon to demonstrate why the Commission should grant the request.

³ The other Joint Petitioners may or may not join this application and reserve their rights with respect to this future application.

- (IV) a statement regarding the duration of the requested waiver or variance, explaining the specific date or event that will terminate it;
- (V) a statement whether the waiver or variance, if granted, would be full or partial; and
- (VI) any other information required by rule.

Decision No. C18-0761, at Ordering Paragraphs 1-2, states as follows:

1. The proposed early retirement of units 1 and 2 at the Comanche generation station, owned and operated by Public Service Company of Colorado (Public Service), is approved as part of its 2016 Electric Resource Plan (ERP), consistent with the discussion above.
2. Public Service shall file an application to amend the Certificates of Public Convenience and Necessity (CPCNs) for Comanche units 1 and 2, pursuant to 4 Code of Colorado Regulations (CCR) 723-3-3103 of the Commission's Rules Regulating Electric Utilities, as modified by this Decision, consistent with the discussion above."

Among other things, Ordering Paragraph 1 approves the Company's plan to retire Comanche Unit 2. Ordering Paragraph 2 requires a limited scope CPCN amendment filing associated with such retirement. The Joint Petitioners seek relief in the form of a variance from the Commission's directive to file a CPCN amendment to effectuate a retirement of the unit by the end of this year, as well as any other requirements the Commission deems necessary. The discussion that follows addresses each rule requirement in more detail.

A. Rule 1003(c)(I): citation to the specific paragraph of the rule or decision from which the waiver or variance is sought.

Joint Petitioners seek a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761; specifically the requirement to file for a CPCN amendment to retire Comanche Unit 2

consistent with the Company's 2016 ERP in Decision No. C18-0761 and any other requirements the Commission deems necessary.

B. Rule 1003(c)(II): a statement of the waiver or variance requested.

The Joint Petitioners seek a variance of 365 days, i.e., until December 31, 2026, for the planned retirement of Comanche Unit 2, with the CPCN filing requirement held in abeyance until that time. In Step 2 defined above, the Joint Petitioners or the Company may bring a longer variance request to the extent necessary. Any longer extension, however, is not at issue here in this proceeding. In addition, neither the Company nor the Joint Petitioners seek any ratemaking relief as part of this Petition. Any such requests can be brought forward and addressed by the Commission in other appropriate proceedings.

C. Rule 1003(c)(III): a statement of facts and circumstances relied upon to demonstrate why the Commission should grant the request.

Section II above outlines the facts, circumstances, and need for the variance requested by the Joint Petitioners. The variance and 365-day extension allows time for the two-step process outlined above to assess future plant operations and resource options. In addition, it provides a level of certainty to system operators and the workers at the unit by having a date certain for the plan to retire the unit. Moreover, it is worth noting that, viewed from a greenhouse gas ("GHG") emissions perspective, a Comanche Unit 2 extension will result in GHG emissions in 2026 from the unit that would not otherwise have occurred; however, that should be viewed in the context of a Comanche Unit 3 outage, where the emissions from the larger Comanche Unit 3 will *not occur*, leading to lower GHG emissions in the first half of 2026 (along with lower GHG emissions in the latter part of 2025). The Company also intends to evaluate the emissions impact, including other

pollutants beyond GHG emissions, and to work with the Colorado Department of Public Health and Environment on that effort.

D. Rule 1003(c)(IV): a statement regarding the duration of the requested waiver or variance, explaining the specific date or event that will terminate it.

The duration of the requested variance is through December 31, 2026. The variance will terminate on that date absent an additional variance request and the subsequent grant of the request by the Commission.

E. Rule 1003(c)(V): a statement whether the waiver or variance, if granted, would be full or partial.

The variance is partial as it is time-limited through December 31, 2026, absent a further variance.

F. Rule 1003(c)(VI): any other information required by rule.

The Joint Petitioners are not aware of any additional information required by rule.

IV. REQUEST FOR SHORTENED NOTICE AND INTERVENTION PERIOD AND RELATED PROCEDURES

The Joint Petitioners request a shortened notice and intervention period pursuant to Rule 1003(b), along with related procedures. Rule 1003(b) states: “If a petition requests a waiver or variance to be effective less than 40 days after the date of filing, the petition must include a request to waive or shorten the Commission notice and intervention period found in paragraph (d) of rule 1206.”

The Joint Petitioners request approval of the procedures and schedule set forth below, which feature: (1) a shortened notice and intervention period of ten calendar days; (2) the filing of responses to the petition *with* any motions to intervene; and (3) a two-calendar day reply timeline

for the Joint Petitioners to address any responses.⁴ The procedures are set forth with specific dates, including a proposed date for Commission deliberation and action.

<i>Process Step</i>	<i>Timing</i>
Joint Petition	+0 (November 10, 2025)
Commission accepts Petition	(November 12, 2025)
Intervention Deadline (petition responses included with interventions)	+10 calendar days after filing (November 20, 2025)
Joint Petitioner Reply	+6 calendar days after response (November 26, 2025)
Commission Deliberation	December 3, 2025
Commission Action	December 10, 2025

V. CONCLUSION AND REQUEST FOR RELIEF

The Joint Petitioners ask for swift Commission action on this Petition, and time is of the essence given the upcoming retirement date for Comanche Unit 2. The Joint Petitioners appreciate the Commission's prompt consideration of this request and the related procedural requests.⁵

The Joint Petitioners request approval of:

- A variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761 and any other requirements deemed necessary by the Commission.
- A shortened notice and intervention period of ten days.
- The procedures for consideration and decision on this Petition set forth above.

The Joint Petitioners further request that the Commission grant this Petition without a hearing.

⁴ The Joint Petitioners are providing electronic courtesy service of this Petition to all parties to Proceeding No. 16A-0396E, Proceeding No. 21A-0141E, and Proceeding No. 24A-0442E given the request for a shortened notice and intervention period and associated procedures here.

⁵ The Joint Petitioners ask the Commission to ensure that the relief sought in this petition will not interfere with the Company's planned or in-progress acquisition or interconnection of new generating resources. Nothing in this proposal shall be construed as the Joint Petitioners' request to alter the Company's proposal to acquire new resources through the NTP and the JTS. The Joint Petitioners strongly encourage the Commission to ensure that the NTP remains on the procedural schedule that the Commission approved, and to move as quickly as possible to conclude the Phase I JTS and proceed to Phase II of the JTS.

Dated this 10th day of November 2025.

Respectfully submitted,

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**ATTORNEYS FOR PUBLIC SERVICE COMPANY
OF COLORADO**

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * *

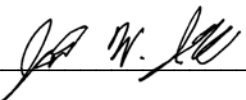
IN THE MATTER OF THE VERIFIED) PETITION OF TRIAL STAFF OF THE) COMMISSION, THE COLORADO) ENERGY OFFICE, THE COLORADO) OFFICE OF THE UTILITY CONSUMER) ADVOCATE, AND PUBLIC SERVICE) COMPANY OF COLORADO) FOR A VARIANCE FROM ORDERING) PARAGRAPHS 1 AND 2 OF DECISION NO.) C18-0761 AND ANY OTHER) REQUIREMENTS)	)	PROCEEDING NO. 25V-____E

VERIFICATION OF JACK W. IHLE

STATE OF COLORADO)
CITY AND COUNTY OF DENVER) SS:

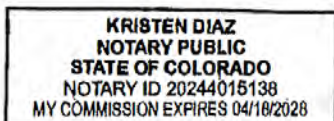
I, Jack W. Ihle, being duly sworn, do hereby depose and state that I am the Regional Vice President, Regulatory Policy, at Xcel Energy Services Inc., and am an authorized agent for Public Service Company of Colorado. I have read the foregoing Verified Petition of Trial Staff of the Commission, the Colorado Energy Office, the Colorado Office of the Utility Consumer Advocate, and Public Service Company of Colorado for a Variance from Decision No. C18-0761 and Any Other Requirements, Request for Shortened Notice and Intervention Period, and Request for Approval of Associated Procedures. The facts set forth therein are true, accurate, and correct to the best of my knowledge, information, and belief.

Dated at Denver, Colorado, this 10th day of November, 2025.



Jack W. Ihle
Regional Vice President, Regulatory Policy
3500 Blake Street
Denver, Colorado 80205

Subscribed and sworn to before me this 10th day of November, 2025.





Notary Public
My Commission expires 4/18/2028

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-21
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit YY: Department, Order No. 202-26-17 (Feb. 23, 2026)



Department of Energy
Washington, DC 20585

Order No. 202-26-17

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, Pennsylvania. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order Nos. 202-25-04 and 202-25-08, issued pursuant to FPA section 202(c), each required that the Eddystone Units remain in operation for 90 days, until August 28, 2025, and November 26, 2025, respectively. Subsequently, Order No. 202-25-10, issued pursuant to FPA section 202(c), required the Eddystone Units to remain in operation for 90 days, until February 24, 2026. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.³ I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.⁴ I determined that continued operation and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest.⁵ My determination was based on a number of different facts.

First, in congressional testimony, PJM's President and CEO stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ See, e.g., *PJM Interconnection, L.L.C. and Constellation Energy Corp.*, Order No. 202-25-10, at 7 (Nov. 25, 2025).

⁴ See, e.g., *id.*

⁵ See, e.g., *id.* at 8, Ordering Paragraph A.

dispatchable resources, and other factors.⁶ Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM’s interconnection queue.⁷ Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that “available generation capacity may fall short of required reserves in an extreme planning scenario.”⁸ In its February 2023 assessment, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM highlighted increasing reliability risks in the coming years due to the “potential timing mismatch between resource retirements, load growth and the pace of new generation entry” under “low new entry” scenarios for renewable generation.⁹

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found “the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry.”¹⁰

⁶ *Keeping the Lights On: Examining the State of Regional Reliability: Hearing Before the Subcomm. on Energy of the H. Comm. on Energy & Com.*, 119th Cong., at 4-5 (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.), <https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf>.

⁷ *Id.* See also *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (PJM states that, in 2023, “it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM’s interconnection queue pose increasing reliability risks through 2030.”).

⁸ PJM Inside Lines, *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk* (May 9, 2025), <https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/>.

⁹ PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, at 1 (Feb. 24, 2023) (Four Rs Report).

¹⁰ *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-04, 202-25-08, and 202-25-10 continue, both in the near and long term.¹¹ The production of electricity from the Eddystone Units will continue to be a critical asset for maintaining reliability in PJM. According to data from the U.S. Environmental Protection Agency, the Eddystone Units generated 26,971 MWh between June 2025 and December 2025,¹² providing vital generation capacity to the region. Over the summer of 2025, PJM took action to manage grid operations, issuing Hot Weather Alerts and/or Maximum Generation Alerts (Energy Emergency Alert (EEA) 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.¹³

PJM's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when PJM operated under a cold weather alert and declared conservative operations from January 24 – February 2, 2026. Additionally, on January 27, 2026, PJM declared a Maximum Generation Emergency/ Load Management Alert and an EEA 1.¹⁴ Due to concerns about resource adequacy from the high demand driven by the extreme cold, PJM also applied for an order pursuant to FPA section 202(c) “that broadly authorizes all electric generating units located within the PJM Region to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages during the pendency of this emergency.”¹⁵ The Department granted PJM's application and issued Order No. 202-26-02 on

¹¹ Further, it likely would be difficult for the oil-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. If Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists.

¹² See *Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), <https://campd.epa.gov/data/custom-data-download> (search criteria Emissions >> Monthly >> Unit (default) >> Apply >> “2025” and “June, July, August, September, October, November, December.” The data can then be filtered to include only the Eddystone Generating Station.

¹³ See PJM, *Emergency Procedures*, <https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf> (search range set to: effective from 06/01/2025 until 08/31/2025).

¹⁴ See *id.* (search range set to: effective from 01/20/2026 until 02/07/2026).

¹⁵ PJM, *Request for Emergency Order Under Federal Power Act, Section 202(c)*, at 2 (Jan. 24, 2026), <https://www.energy.gov/documents/pjm-202c-application-2026-01-24>.

January 25, 2026.¹⁶ On January 29, 2026, PJM applied for an extension of Order No. 202-26-02, which was granted by the Department on the same day.¹⁷

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.¹⁸ PJM notes that the "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."¹⁹ Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.²⁰

The evidence indicates that there is also a potential longer term resource adequacy emergency in the PJM region. In a news release expressing support for Order No. 202-25-04, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."²¹

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.²² PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for

¹⁶ *PJM Interconnection, L.L.C.*, Order No. 202-26-02 (Jan. 25, 2026).

¹⁷ *PJM Interconnection, L.L.C.*, Order No. 202-26-02A (Jan. 29, 2026).

¹⁸ PJM Inside Lines, *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand* (Jan. 22, 2025), <https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/>.

¹⁹ PJM Inside Lines, *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand* (Jan. 30, 2025), <https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/>.

²⁰ PJM Resource Adequacy Planning Special Planning Committee, *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk*, at 8 (Mar. 13, 2025), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf>.

²¹ PJM Inside Lines, *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30* (May 31, 2025), <https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/>. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint" *Id.*

²² Four Rs Report at 2.

renewable projects is approximately 5%.²³ PJM determined that the pace of new capacity additions “would be insufficient to keep up with expected retirements and demand growth by 2030.”²⁴ PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.²⁵

In its December 2024 RRI filing with FERC, PJM stated that “[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report”²⁶ PJM warned that its “resource adequacy concerns are increasing at an extraordinary pace.”²⁷ PJM went on to explain that its “resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers,” and that its preliminary analysis shows “substantial increases [in load additions] since the 2024 forecast” for both the summer and winter seasons.²⁸ According to PJM, “load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence.”²⁹ Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.³⁰

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM’s Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as “extraordinary” and “unprecedented,” stating that it “could not have been foreseen as recently as a year ago.”³¹ Mr. Bielak expressed the opinion that the “rapid” retirement of thermal generation resources, “extreme” forecasted load growth, and “delays in new generation resources achieving commercial operation,” would adversely affect resource adequacy throughout PJM’s electricity grid.³²

²³ *Id.*

²⁴ *Id.* at 16, Table 1.

²⁵ *Id.*

²⁶ PJM, *Tariff Revisions for Reliability Resource Initiative*, FERC Docket No. ER25-712, at 10 (Dec. 13, 2024).

²⁷ *Id.*

²⁸ *Id.* at 10-11. *See also id.* at 13 (“the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . .”).

²⁹ *Id.* at 14.

³⁰ *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, “could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.”).

³¹ Affidavit of Mr. Donald Bielak at P 10.

³² *Id.* at P 12.

On February 11, 2025, FERC accepted PJM’s RRI filing.³³ In its order on rehearing, FERC concluded that “PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest.”³⁴

The North American Electric Reliability Corporation (NERC) has raised similar concerns. In its 2025 Long-Term Reliability Assessment, released in January 2026, NERC observes that the PJM region is at high risk of energy shortfalls over the next five years³⁵ and faces significant reliability challenges as “[c]urrent projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements.”³⁶ The assessment notes that “[d]emand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads;” however “[a]t the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays.”³⁷ Overall, the assessment concludes that “[b]ased on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.”³⁸

Order Nos. 202-25-04, 202-25-08, and 202-25-10 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our nation’s economy, national security, and foreign policy.”³⁹ The Executive Order adds, “hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international

³³ *PJM Interconnection*, 190 FERC ¶ 61,084 at P 263.

³⁴ *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

³⁵ NERC, *2025 Long-Term Reliability Assessment*, at 7, Figure 1 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

³⁶ *Id.* at 8.

³⁷ *Id.* at 16.

³⁸ *Id.* at 91.

³⁹ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

commodity markets.”⁴⁰ In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”⁴¹

Further, the Department detailed the myriad challenges affecting the nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”⁴² The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.⁴³ As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.⁴⁴ In collaboration with the national labs, the Department modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.⁴⁵ Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a maximum unserved load of approximately 21.335 GW.⁴⁶

⁴⁰ *Id.*

⁴¹ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

⁴² U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025) (Resource Adequacy Report), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

⁴³ See PPL Corporation, *PPL Corporation Q2 2025 Investor Update*, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINA L.pdf.

⁴⁴ See Dominion Energy Virginia, *Q4 2024 Earnings Call*, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slidesvTCII.pdf.

⁴⁵ Resource Adequacy Report at 28.

⁴⁶ *Id.* at 27.

Grid operators, including PJM, have likewise acknowledged the nation's current energy crisis. For instance, during a hearing before the United States House of Representatives Committee on Energy and Commerce on March 25, 2025, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."⁴⁷ Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."⁴⁸ Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.⁴⁹ Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."⁵⁰

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."⁵¹ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

⁴⁷ Asthana Test. at 4.

⁴⁸ *Id.*

⁴⁹ *Id.* at 9-10.

⁵⁰ *Id.* at 10.

⁵¹ Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from the combination of increasing demand and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-04, 202-25-08, and 202-25-10 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the increased demand for emergency and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Eddystone Units will be available if needed to address emergency conditions, they shall remain in operation through May 24, 2026.⁵²

Based on my determination of an emergency set forth above, I hereby order:

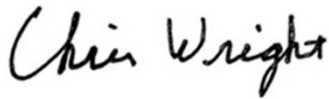
- A. From February 24, 2026, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.
- C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.
- D. By March 11, 2026, PJM is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this

⁵² 16 U.S.C. § 824a(c)(4).

Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

- E. Constellation Energy is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.
- H. This Order shall be effective on February 24, 2026, through May 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of February 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Pennsylvania Public Utility Commissioners
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zeffuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Craig Unit 1	)	Order No. 202-26-21
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit Z: CoPUC, Tri-State, *2025 Annual Progress Report*, filed on December 1, 2025,
in Proceeding No. 23A-0585E



Tri-State Generation and Transmission Association, Inc.



2025 Annual Progress Report

2023 Electric Resource Plan
Colorado Public Utilities Commission
Proceeding No. 23A-0585E

December 1, 2025

Forward-Looking Statement

Forward-looking statements include statements concerning our plans, objectives, goals, strategies, future events, future revenue or performance, forecasts, including load, energy, resources, and commodities, future capital expenditures, capacity needs, plans or intentions relating to development, acquisition, operation, or closure of facilities, in-service dates of facilities, emission reductions, demand response targets, energy efficiency targets, Member withdrawals, business trends or business strategy and other information that is not historical information. When used in this Annual Progress Report, the terms "estimates," "expects," "anticipates," "projects," "plans," "intends," "believes" and "forecasts" or future or conditional verbs, such as "will," "should," "could" or "may," and variations of such words or similar expressions, are intended to identify forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties, and assumptions, including those described in our filings with the Securities and Exchange Commission. All forward-looking statements, including, without limitation, management's examination of historical operating trends and data, are based upon our current expectations and various assumptions. These expectations and beliefs are expressed in good faith grounded in a reasonable basis. However, we cannot guarantee that management's expectations and beliefs will be achieved. There are a number of risks, uncertainties, and other important factors that could cause actual results to differ materially from the forward-looking statements contained in this Annual Progress Report.

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Introduction

Tri-State Generation and Transmission Association, Inc. (“Tri-State”) filed Phase I of its 2023 Electric Resource Plan (“ERP” or “Resource Plan”) with the Colorado Public Utilities Commission (“Commission”) on December 1, 2023 in Proceeding No. 23A-0585E. At the time of this report, Phase II resource acquisitions remain ongoing, pursuant to Decision No. C25-0612. In compliance with Commission Rule 3618(a), Tri-State submits the following Annual Progress Report (“APR”) on its efforts under its electric resource plan.

As discussed below, Tri-State is forecasting a need for 19 MW of additional generation capacity by summer 2035.¹ This forecast incorporates existing resources, 2023 ERP Phase II preferred portfolio resources, and planned unit retirements.

This 2025 APR contains the following sections, in compliance with Commission Rule 3618(a):

- A. An updated annual electric demand and energy forecast;
- B. An updated evaluation of existing resources;
- C. An updated evaluation of planning reserve margins and contingency plans;
- D. An updated assessment of need for additional resources;
- E. An updated report of the utility’s action plan and resource acquisitions; and
- F. An explanation of Tri-State’s efforts to give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions.
- G. An update on Tri-State’s progress toward its GHG emissions reduction targets.

The intent of the APR is to discuss material changes in assumptions, fleet characteristics, load forecasts and other factors that have occurred since the 2024 APR and 2023 ERP Phase II were filed. To the extent issues addressed in Tri-State’s 2024 APR or 2023 ERP Phase I and Phase II filing have not materially changed, they are not addressed herein.

¹ 2024 APR: 11 MW need projected starting in 2030
2023 ERP: 68 MW need projected starting in 2029
2022 APR: 126 MW need projected starting in 2030
2021 APR: 248 MW need projected starting in 2030
2020 ERP: 95 MW need projected starting in 2029
2019 APR: 70 MW need projected starting in 2027
2018 APR: 115 MW need projected starting in 2026
2017 APR: 148 MW need projected starting in 2026
2015 ERP: 9 MW need projected starting in 2023

Tri-State has made several changes to its resource portfolio in recent years reflecting increasing amounts of renewable resources and lower emissions trajectory, notably:

- Craig Unit 1² is planned to cease operations by December 31, 2025, Craig Unit 3 will retire January 1, 2028, and Craig Unit 2³ will retire by September 30, 2028.
- Springerville Unit 3 (“SPV 3”) is planned to cease operations by March 1, 2031.⁴
- Two solar projects came online in 2024 in Colorado, Spanish Peaks Solar (100 MW) and Spanish Peaks II Solar (40 MW) in Las Animas County.
- Two solar projects came online at the end of October 2025 in Colorado, Axial Basin Solar (145 MW) in Moffat County and Dolores Canyon Solar (110 MW) in Dolores County.

1. Updated Annual Electric Demand and Energy Forecast

Commission Rule 3618(a)(I)

Tri-State’s most current demand and energy forecast was modeled in 2023 ERP Phase II and no subsequent revisions have been made. The forecast reflected in Table 1 represents Tri-State’s System Wide annual energy and seasonal peaks as modeled in 2023 ERP Phase II. Subsequent to the commencement of modeling in Phase II, Tri-State received notice from the Northwest Rural Public Power District in Nebraska (“NRPPD”) that it intends to depart Tri-State Utility Membership on January 1, 2027. NRPPD is served solely in the Eastern Interconnection through an all requirements contract, and NRPPD’s departure does not impact Tri-State’s electric demand and energy forecast for purposes of Tri-State’s Colorado ERP.⁵

² Tri-State’s ownership share is 102 MW (24%) of this unit, which has a total nameplate capacity of 427 MW.

³ Tri-State’s ownership share is 98 MW (24%) of this unit, which has a total nameplate capacity of 410 MW.

⁴ Decision No. R24-0602 found that a retirement date of September 15, 2031 for SPV 3 was reasonable contingent upon Tri-State receiving a New ERA funding award and successful negotiation of contractual agreements impacted by the unit’s retirement. The New ERA award is contingent upon a March 1, 2031 retirement date for SPV 3, consistent with the requirement for USDA to disperse all New ERA funds by September 30, 2031.

⁵ See Attachment B to Tri-State’s Phase II Implementation Report, filed April 11, 2025 in Proceeding No. 23A-0585E.

TABLE 1 – 10-YEAR DEMAND AND ENERGY FORECAST

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Sales (GWh)	13,051	13,110	13,455	13,642	13,830	14,049	14,289	14,521	14,773	15,036
Winter Peak Demand (MW)	1,865	1,739	1,778	1,825	1,847	1,888	1,886	1,955	1,998	2,038
Summer Peak Demand (MW)	2,344	2,423	2,454	2,431	2,472	2,535	2,583	2,635	2,646	2,629

2. Updated Evaluation of Existing Resources

Commission Rule 3618(a)(II)

Figure 1 below depicts the sources of generation serving Tri-State’s 2024 total energy sales. Figure 2 below depicts Tri-State’s 2024 capacity by generation source. Tri-State’s assessment of its existing resources remains the same as what was presented in Tri-State’s 2023 ERP Phase I.

FIGURE 1 – 2024 ENERGY MIX, GROSS SALES

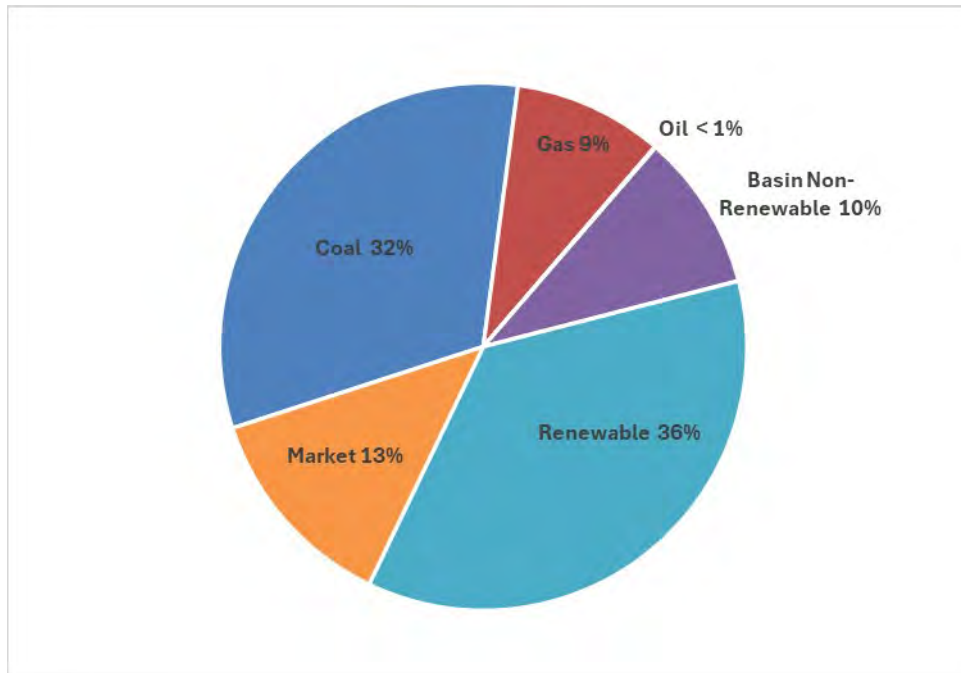
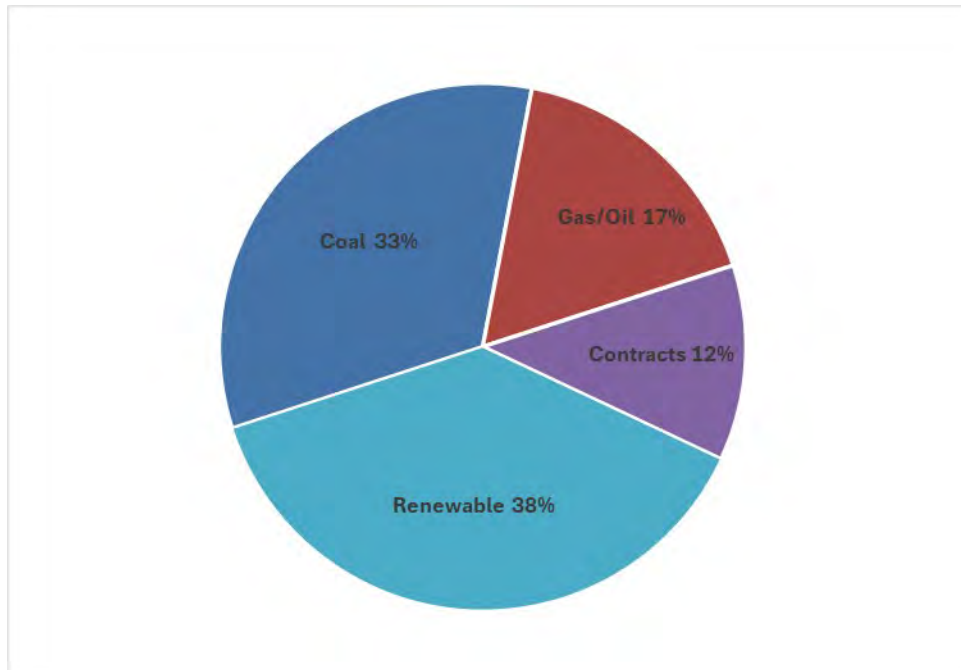


FIGURE 2 – 2024 CAPACITY PORTFOLIO



3. Updated Evaluation of Planning Reserve Margins and Contingency Plans

Commission Rule 3618(a)(III)

There are no updates or changes to the planning reserve margin (“PRM”) or contingency plans from those contained in Tri-State’s 2023 ERP Phase I or Phase II filing.⁶ Tri-State continues to base its resource plans on a 22% PRM until the retirement of Craig Unit 3, after which the PRM increases to 30.5% beginning in 2028. Tri-State’s participation in reserve sharing agreements and bilateral hazard-sharing arrangements provide additional support for reliable operations.

Tri-State continues to plan for its WACM load and resources to enter the Southwest Power Pool (“SPP”) RTO in April 2026. Once in the RTO, Tri-State’s assets in the WACM BA authority will be subject to SPP’s PRM requirements. Tri-State is evaluating the SPP PRM requirements and will compare them to Tri-State’s most recent PRM requirement. Tri-State intends to follow the more stringent of the two PRM requirements for its system planning.⁷

4. Updated Assessment of Need for Additional Resources

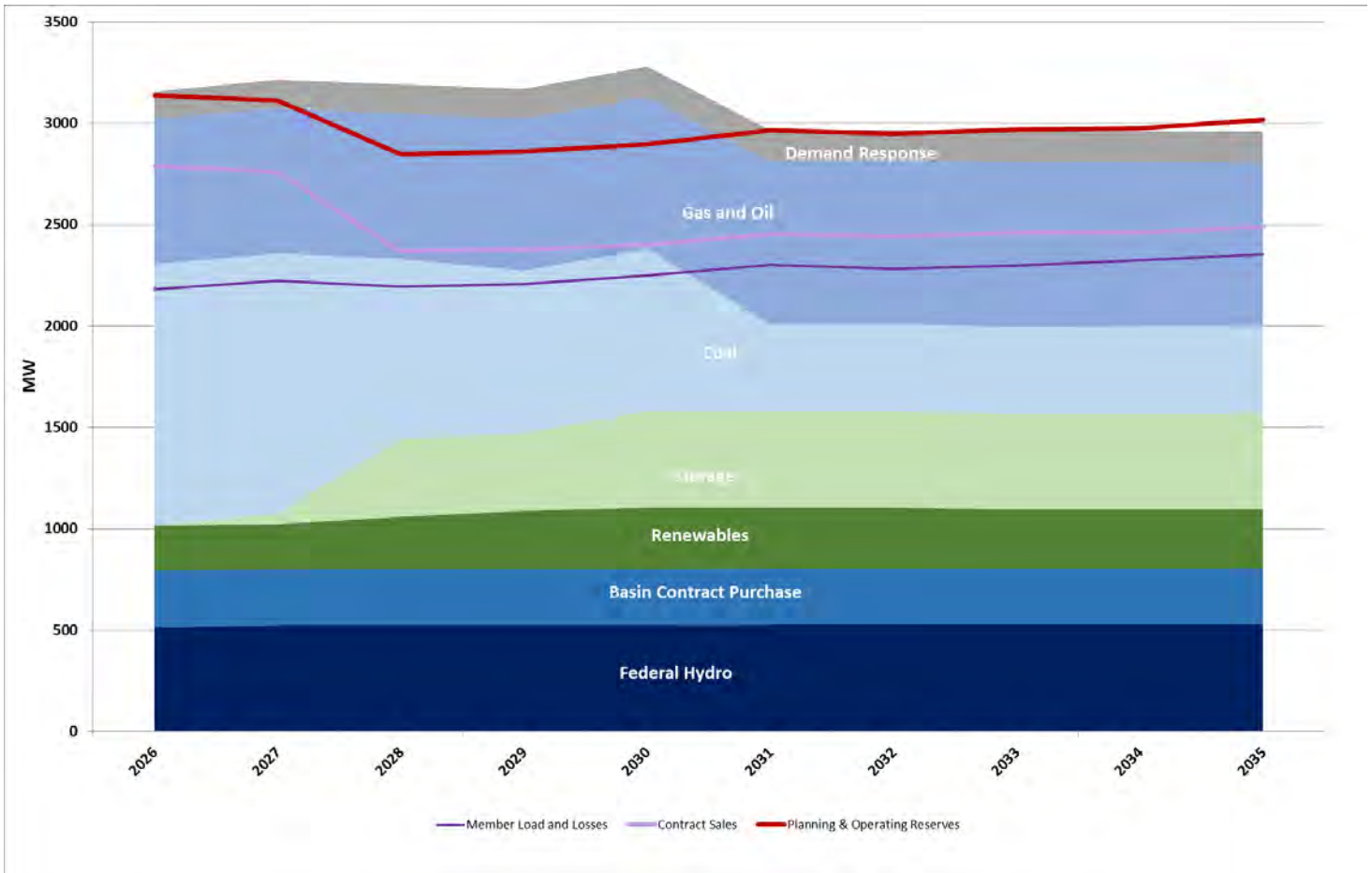
Commission Rule 3618(a)(IV)

Tri-State stated within Phase I of the 2023 ERP that it did not forecast a capacity shortfall until 2029. With the updated load forecast, shown above, utilized in Phase II and Phase II preferred portfolio resources, a capacity shortfall is not forecasted to occur until 2035, as shown in Figure 3 and Table 2 below. Tri-State’s electrically east load is supplied by a full requirements contract with Basin Electric Power Cooperative and is not included in the load or resource portion of Figure 3 and Table 2.

⁶ LKT-1 - Attachment G-1 - Confidential - ELCC and PRM Study (Astrape) filed December 1, 2023 in Proceeding No. 23A-0585E.

⁷ Response Comments of Tri-State Generation and Transmission Association, Inc., Proceeding No. 25A-0266E.

FIGURE 3 –LOAD AND RESOURCES



The data for Figure 3 is shown in Table 2.

TABLE 2 – LOAD AND RESOURCES

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Federal Hydro	516	524	523	524	525	527	527	527	527	527
Contract Purchases	278	278	278	278	278	278	278	278	278	278
Renewables ⁸	224	221	259	285	303	299	299	290	291	291
Demand Response	134	141	144	147	149	151	152	153	154	155
Coal Generation ⁹	1287	1286	888	800	431	431	432	431	432	431
Gas & Oil Generation ¹⁰	717	717	717	751	751	806	806	806	806	806
Storage ¹¹	0	49	383	383	474	474	474	474	474	474
Total Resources	3155	3215	3193	3169	3280	2965	2967	2959	2961	2961
Member Load and Losses ¹²	2180	2223	2195	2206	2249	2302	2282	2297	2323	2355
Planning & Operating Reserves	350	351	478	482	495	511	505	509	517	527
Contract Sales	608	536	173	173	151	151	162	162	135	135
Total Obligations	3138	3110	2846	2861	2895	2964	2949	2968	2976	3017
Excess Resources	8	89	372	335	412	30	46	19	22	-19

5. Updated Report of the Utility's Action Plan and Resource Acquisitions

Commission Rule 3618(a)(V)

Tri-State's 2023 ERP Phase II procurement process is underway. Bids were received on October 28, 2024, in response to three Phase II requests for proposals.¹³ A summary of bids was filed in Proceeding No. 23A-0585E on December 12, 2024;¹⁴ and bids selected in the Phase II preferred portfolio were identified in Tri-State's ERP Implementation Report filed April 11, 2025. Tri-State has 500 MW of preferred portfolio storage resources under contract, 200 MW of preferred portfolio wind resources under contract, and is continuing contracting efforts for other preferred

⁸ Capacity is based on applying the effective load carrying capability by renewable technology to the nameplate of renewable resources.

⁹ Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.

¹⁰ Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.

¹¹ Capacity is based on applying the effective load carrying capability for storage to the nameplate of storage resources.

¹² Western Interconnection Load.

¹³ Bids for the Dispatchable RFP were received November 27, 2024.

¹⁴ See Tri-State's 45-Day Report filed in Proceeding No. 23A-0585E.

portfolio resources, including evaluation of back-up bids as needed. The preferred portfolio bids under contract include:

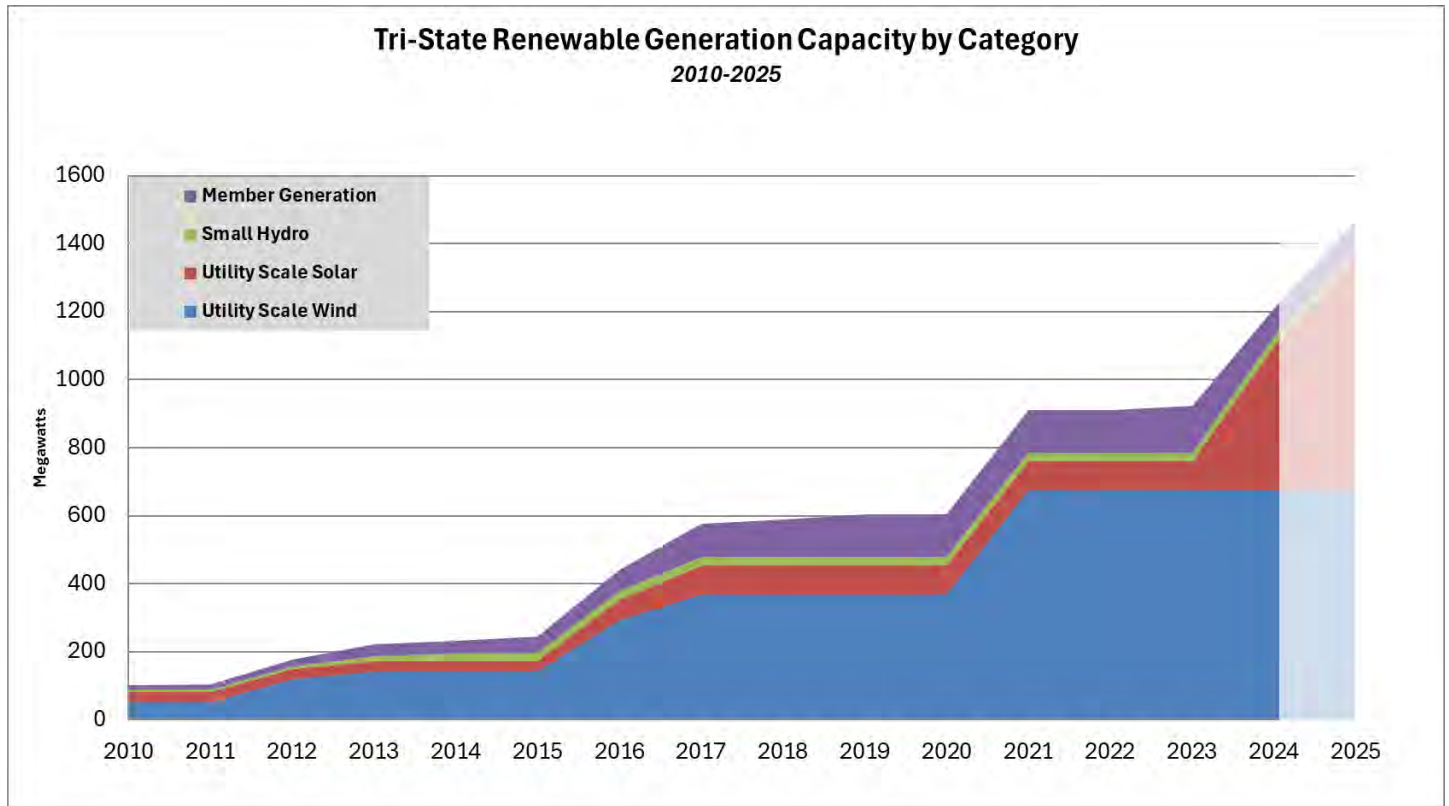
- High Country Energy Station 2 (Montrose County, CO), 50 MW, Q2-2027 COD;
- Oso Negro Energy Storage (Bernalillo County, NM), 100 MW, Q2-2028 COD;
- Morel Energy Storage (Moffat County, CO), 200 MW, Q1-2030 COD;
- Carousel Energy Storage (Kit Carson County, CO), 150 MW, Q4 2027 COD; and
- Arriba Wind (Lincoln County, CO), 200 MW, Q1 2029 COD.

Expansion of Renewable Energy Portfolio

Tri-State's first owned renewable energy resources, Axial Basin Solar (145 MW) and Dolores Canyon Solar (110 MW) came online in October 2025. With those additions, along with existing renewable PPA resources, the renewable resources on Tri-State's system total approximately 2 GW.¹⁵ Tri-State's renewable generation capacity, actuals through 2024 and forecasted for 2025, is shown in Figure 4 below.

¹⁵ 1,466 MW wind, solar, small hydro, and renewable Member generation; and 580 MW large hydro.

FIGURE 4 – TRI-STATE RENEWABLE GENERATION CAPACITY¹⁶



6. Update on Consideration of Acquisition of Cost-Effective New Clean Energy and Energy-Efficient Technologies

Commission Rule 3618(a)(VI)

Emerging Technologies

Tri-State expanded its generic resource data set for Phase I of the 2023 ERP to include additional clean energy and energy efficient technologies, as technologies continue to evolve and become more competitive.¹⁷ Tri-State utilizes the Electric Power Research Institute (“EPRI”) for advanced generation and storage research, input from internal Tri-State Generation Engineering staff, industry benchmarking, and relationships with vendors, stakeholders, and consultants to stay aware of the progress of emerging technologies at a utility scale that can assist in a clean

¹⁶ Figure 4 does not include Western Area Power Administration Colorado River Storage Project or Loveland Area Projects hydro allocations.

¹⁷ See Hearing Exhibit 101, Attachment LKT-16, Rev. 2, filed on May 15, 2024, in Proceeding No. 23A-0585E.

energy transition to maintain affordability and reliability for Tri-State's Utility Member Systems. Tri-State will continue to evaluate emerging technologies to consider for its 2027 ERP generic resource data set, to the extent the resources are utility-scale proven and cost-competitive.

Tri-State's entry of its resources into the SPP RTO in April 2026 is key for integrating intermittent resources on a large scale and further supporting affordable and reliable operations, while meeting carbon reduction targets.

Renewables

Tri-State's renewable resource portfolio includes utility scale projects and distribution level projects. Tri-State's wholesale power contract with each of its Utility Members and Board policies allow for, and facilitate, the development of local distributed resources in its Utility Members' service territories. The Federal Energy Regulatory Commission ("FERC") accepted, subject to refund and settlement procedures, Tri-State's amended Board Policy 115 effective August 6, 2025, enabling Utility Members to now self-supply up to 20% of their energy needs through distributed or renewable generation, a substantial increase from the previous 5% allocation. These renewable and distributed projects are helping to fulfill both Colorado and New Mexico Renewable Energy Standards ("RES")/Renewable Portfolio Standards ("RPS") requirements, as well as satisfy Utility Members'/consumers' interests in purchasing renewable power from locally-sited projects.

Figure 5 below shows the decline in capacity of these distributed projects through the end of 2024, reflecting the departures of United Power and Mountain Parks Electric, accounting for a decrease in distributed generation capacity of 49.6 MW. The number and capacity of these projects is expected to continue to grow, with a small net increase in 2025, as many of Tri-State's Utility Members remain interested in supporting local renewable projects.

FIGURE 5 – MEMBER RENEWABLE AND DISTRIBUTED GENERATION PROJECTS, NAMEPLATE CAPACITY UNDER CONTRACT, 2007-2024 AND FORECASTED for 2025

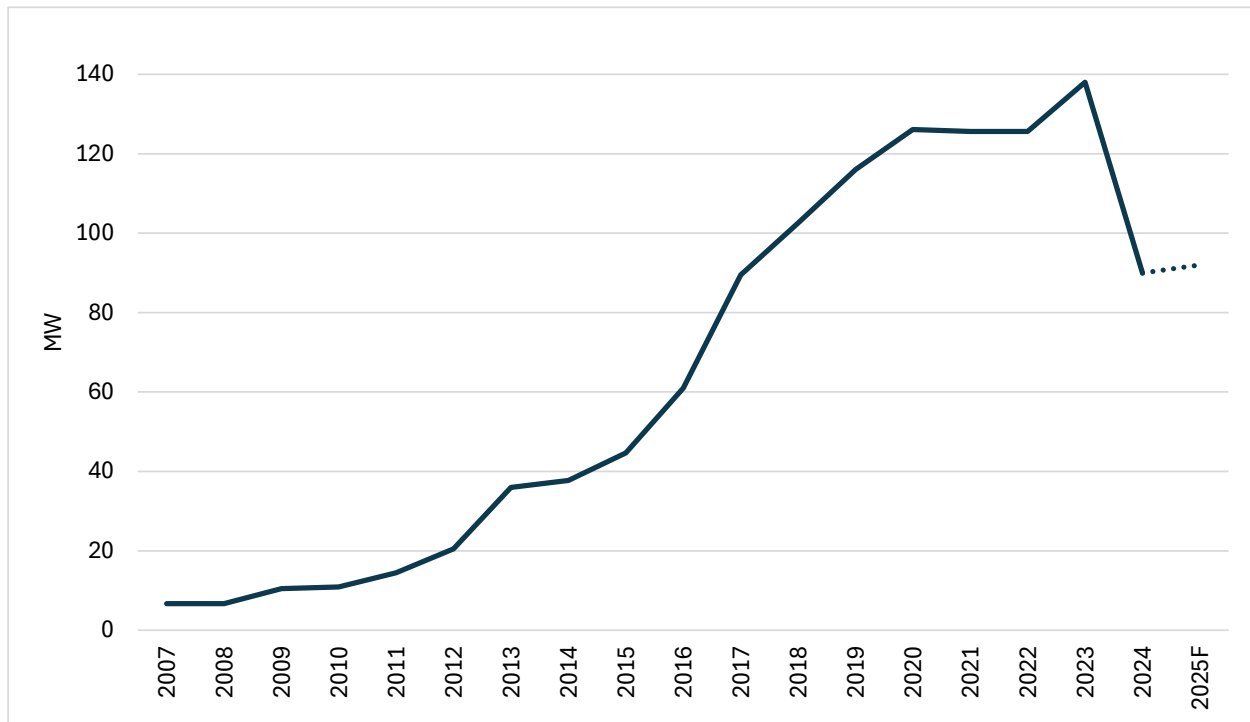
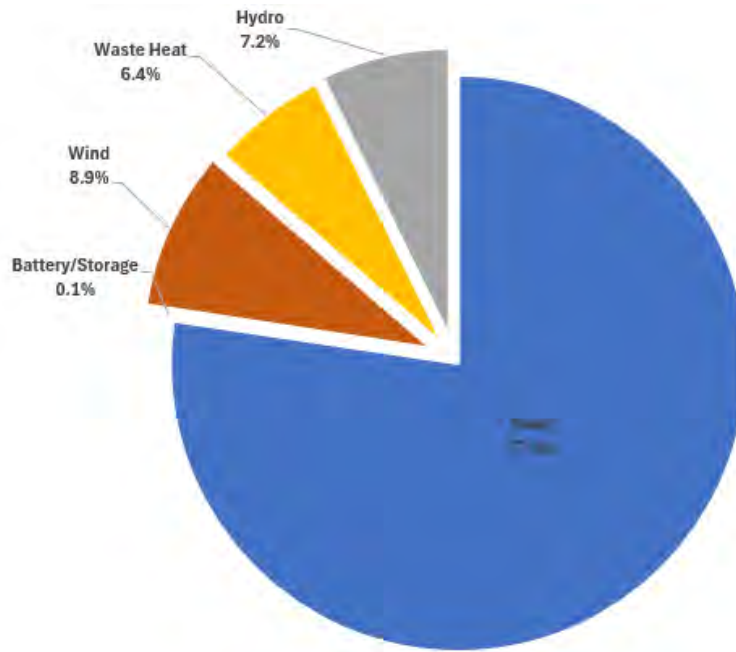


Figure 6 shows the breakdown of these projects by technology category. As of December 31, 2024, fifty-eight renewable or distribution generation projects totaling 90 MW were in operation across 20 Member Systems, with solar technology comprising over 77% of Member generation distributed resources.

FIGURE 6 – MEMBER BP 115 RENEWABLE AND DISTRIBUTED GENERATION PROJECTS BY TECHNOLOGY,
NAMEPLATE CAPACITY OPERATING AS OF 12/31/2024



Bring Your Own Resource (BYOR)

Tri-State's BYOR program was accepted by FERC on August 2, 2025. Within this program Utility Members can bring forth resources equivalent up to 40% of their peak capacity needs through their owned or controlled projects, with Tri-State supporting all Utility Members by integrating BYOR projects into its multi-state system. BYOR allows Utility Members to have additional flexibility to develop resources under their Wholesale Electric Service Contracts with Tri-State, while not increasing wholesale rates or shifting costs between Utility Members. All load served under the BYOR resources remains Class A load.

Energy Efficiency

In 2024, Tri-State's long-standing energy efficiency program spent a total of \$5.8 million on incentives in support of energy efficiency and certain electrification programs (not including administrative costs associated with this program). The programs delivered 56,133 MWh of first-year savings in Colorado, and an estimated 322,612 MWh of lifetime energy savings resulting from 2024 efficiency installations. Annual and cumulative savings from the program through 2024, including the removal of all items that have reached their established end of useful life, are shown in Figure 7 below.

FIGURE 7 – TRI-STATE 2024 ENERGY EFFICIENCY MEASURES AND SAVINGS, CUMULATIVE AND ANNUAL

Cumulative			
Category	Typical Measures	kW Savings	kWh Savings
Agricultural	Irrigation Motors		
	Variable Speed Drive Retrofits	13,065	22,226,468
C&I HVAC	Air Source and Ground Source Heat Pumps	3,471	2,716,881
C&I Lighting	LED Lighting		
	Street & Parking Lot Lighting		
	Refrigerated Case Doors	47,229	175,876,342
C&I Motors	Variable Speed Drive Retrofits and Process Measures	9,403	48,493,751
Residential HVAC	Air Conditioners		
	Air Source and Ground Source Heat Pumps	50,255	42,700,554
Residential - Other	LED Lamps, Energy Star Appliances		
	Electric Water Heaters		
	Low Income Weatherization	54,728	30,597,885
Total		178,151	322,611,881

Annual Savings			
Category	Typical Measures	kW Savings	kWh Savings
Agricultural	Irrigation Motors		
	Variable Speed Drive Retrofits	738	1,175,175
C&I HVAC	Air Source and Ground Source Heat Pumps	139	447,190
C&I Lighting	LED Lighting		
	Street & Parking Lot Lighting		
	Refrigerated Case Doors	1,294	4,938,378
Industrial	Process Measures	3,076	36,674,828
Residential HVAC	Air Conditioners		
	Air Source and Ground Source Heat Pumps	5,086	11,187,795
Residential - Other	LED Lamps, Energy Star Appliances		
	Electric Water Heaters		
	Low Income Weatherization	1,127	1,710,328
Total		11,459	56,133,693

On September 1, 2022, Tri-State submitted its 2023/24 Colorado Demand-Side Management (“DSM”) Plan, informationally, in Proceeding No. 20A-0528E. The DSM Plan describes Tri-State energy efficiency programs and its plans to scale programs to meet energy savings targets agreed upon in the 2020 ERP Settlement Agreement (“Colorado EE Targets”), which began in 2023.

By the end of 2024, Tri-State met its second Colorado EE Target.

2024 Colorado EE Target		2024 Colorado EE Achievement	
0.50%	45.6 GWh	0.61%	56.6 GWh

The programs that contributed most significantly to the 2024 EE Target included: Air-Source Heat Pumps for Space Conditioning, Commercial Lighting, Oil and Gas, and Commercial and Industrial (“C&I”) savings.

Tri-State anticipates meeting its 2025 Colorado EE Target due to growth in oil and gas (“O&G”) sector energy efficiency projects. As of October 2025, Tri-State’s EE program savings is 36.1 GWh or 60.1% of the 2025 Tri-State’s goal of 60.04 GWh (0.75% of Colorado Member load). Tri-State held informational DSM Roundtable Meetings with interested stakeholders on June 17, 2025 and November 12, 2025.

Demand Response

Tri-State is committed to the development of in-house demand response (“DR”) programs designed to meet the target of 4% of Colorado peak load under control in 2025 (“2025 Colorado DR Target”).¹⁸

2025 Colorado DR Target	
4%	59.5 MW

Tri-State’s Demand Response Rider was accepted by the Federal Energy Regulatory Commission (“FERC”) effective May 2025.¹⁹ Following FERC acceptance, Tri-State’s DR programs became available to the entirety of the Tri-State Utility Membership in late May 2025, subject to Tri-State and relevant vendor implementation resources. These programs include:

- Irrigation Load Control
- Commercial & Industrial Load Control

¹⁸ 2020 ERP Phase I Settlement Agreement, section 3.11.8. states: “Tri-State will either conduct an RFP for demand response prior to submitting its next ERP or develop in-house demand response offerings in Colorado by 2025 that are designed to control at least 4% of Tri-State’s Colorado peak load.”

¹⁹ Docket No. ER25-1733.

- Smart Thermostats
- Member Battery Energy Storage

Between 2026 and 2029, Tri-State will continue to evaluate additional program concepts to support reaching the 2030 Colorado DR Target,²⁰ including but not limited to water heater controls, electric vehicle charging, and distribution-scale virtual power plants.

In 2025, Tri-State worked with its contracted partner, OATI, to implement a new Distributed Energy Resource Management System (“DERMS”) which is a platform that enables event scheduling, DR and Distributed Energy Resource (“DER”) integration and dispatch, DR/DER meter data analysis, and reporting. Most facets of the OATI DERMS are now operational for Tri-State users, with development resources now focused on Member system integrations. Tenants of the OATI DERMS platform will be made available to participating Utility Members, subject to terms and conditions of the Demand Response programs. Additionally, Tri-State has partnered with an outside consultant to assist with program design recommendations, in collaboration with Utility Members.

As of November 2025, the total DR capacity enrolled is 40 MW; in addition, approximately 45 battery assets are slated for enrollment once associated funding is released and will join the DR program at that time. Through the remainder of the year, Tri-State is working with Utility Members to continue to implement DERMS tenants and enroll additional C&I, residential and irrigation load, as well as battery storage resources. Tri-State informed stakeholders of its delay in implementing the DR program, and provided an update on the new DR Rider, during the June 17, 2025 DSM Roundtable Meeting.

7. Update on Emissions Reductions

In January 2022, Tri-State filed a Settlement Agreement with numerous parties to its 2020 Phase I ERP. Emissions reductions were among the many topics addressed through the Settlement Agreement. Tri-State agreed to emissions reduction targets for Tri-State’s wholesale sales of electricity in Colorado, with respect to Tri-State’s APCD-verified 2005 Baseline, as follows:

²⁰ 2023 ERP Phase I Settlement Agreement, section 4.9.1 states: “Tri-State will aim to control at least 5.5% of Tri State’s Colorado peak load through demand response programs by 2030.”

TABLE 3 – GHG EMISSIONS REDUCTION TARGETS²¹

Year	Percentage GHG Emissions Reduction
2025	26%
2026	36%
2027	46%
2030	80%

Tri-State also committed to including the following information in its APRs in each year following a year shown in Table 3:²²

- The amount of GHG emissions, in tons, related to Tri-State’s wholesale sales of electricity in Colorado for the prior calendar year, as reported by Tri-State to the Colorado Air Quality Control Commission under Regulation 22; and
- The percentage reduction in GHG emissions related to Tri-State’s wholesale sales of electricity in Colorado for the prior calendar year, computed using the CEP Guidance and the 2005 Baseline. The percentage reduction will be consistent with the tonnages that Tri-State reports under Regulation 22.
- Information on how the emission rate for unspecified energy purchases specified by the CEP Guidance differed from the actual annual reported emissions rate for those purchases. Tri-State also will provide information as to whether any adjustments in operations or resource acquisitions are needed in order to ensure Tri-State meets the targets.

Tri-State will begin reporting this information in its December 2026 APR, for the 2025 GHG emissions reduction target.

As of October 31, 2025, Tri-State is forecasting a ~31% reduction in greenhouse gas (GHG) emissions from energy serving its Colorado load, from a 2005 baseline; the 2025 target is a 26% reduction,²³ making Tri-State on-target toward achieving its first Colorado emissions reduction milestone.

²¹ Section 3.3.4. of the Settlement Agreement filed in Proceeding No. 20A-0528E.

²² Section 3.3.11. of the Settlement Agreement filed in Proceeding No. 20A-0528E.

²³ Section 3.3.4. of the Settlement Agreement filed in Proceeding No. 20A-0528E.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	Order No. 202-26-21
Emergency Order: Craig Unit 1	)	
	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit ZZ: Department, Order No. 202-26-18 (Mar. 16, 2026)



Department of Energy
Washington, DC 20585

Order No. 202-26-18

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

TransAlta Centralia Generation ("Centralia") is an electric generating facility in Centralia, Washington. Centralia is owned and operated by the TransAlta Centralia Generation LLC ("TransAlta"). Centralia consists of one remaining coal-fired generation unit, Unit 2, with a nameplate capacity of 729.9 MW.³ Unit 2 began operations in 1973 and was slated to cease operations in December 2025. Unit 1 was retired in 2020. Unit 2 was slated to cease operation in December 2025 based on a 2011 Washington law⁴ and a subsequent agreement between TransAlta and the State of Washington.⁵ TransAlta has announced plans to convert the unit to natural gas by 2028.⁶

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ U.S. Energy Information Administration, *Form EIA-860, Schedule 3: Generator Data (2024)* (2024 Form EIA-860), (September 09, 2025), <https://www.eia.gov/electricity/data/eia860/>.

⁴ Act of Apr. 29, 2011, Ch. 180, 2011 Wash. Laws, <https://leg.wa.gov/CodeReviser/documents/sessionlaw/2011pam4.pdf>.

⁵ See MOA (Dec. 23, 2011), <https://ecology.wa.gov/getattachment/858591f6-dd25-47be-ba1d-0f58264ca147/20111223TransAltaMOA.pdf> ("D. In exchange for the benefits of entering into an MOA with the State pursuant to RCW 80.80.100, the Company will . . . (5) permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives . . ."); see also First Amendment to MOA (July 13, 2017), <https://fortress.wa.gov/ecy/ezshare/AQ/PDFs/TransAltaMOAAmend1-20170713.pdf>. As a coal-fired facility, it would be difficult for the Centralia Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if TransAlta were to begin disassembling the plant or other related facilities, the associated challenges

Order Nos. 202-25-11 and 202-25-11B, issued pursuant to FPA section 202(c), required that Centralia remain in operation for 90 days, until March 16, 2026. Those orders were based on my determination that emergency conditions existed in the WECC Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes.

Specifically, I determined that the WECC Northwest region is at an elevated risk of insufficient operating reserves during periods of extreme weather.⁷ I determined that the continued operation of Centralia would provide additional generation capacity during these periods, which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.⁸ I determined that the continued operation of Centralia was necessary to alleviate immediate and anticipated threats to reliability.⁹ My determination was based on a number of facts.

First, in its 2025–2026 Winter Reliability Assessment, NERC finds that the WECC Northwest region, which includes Montana, Oregon, Washington, and parts of northern California and northern Idaho, is at elevated risk during periods of extreme weather.¹⁰ The assessment notes that “there is sufficient capacity in the area for expected peak conditions; however, [balancing authorities] are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year.”¹¹

Second, in a September 2025 report evaluating Resource Adequacy in the Pacific Northwest, Energy + Environmental Economics (E3) determined that “[a]ccelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030”¹² and that “[l]oad growth and retirements mean the region faces a

would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

⁶ TransAlta, *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion* (Dec. 9, 2025), <https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/>.

⁷ See, e.g., *TransAlta*, Order No. 202-25-11, at 1 (Dec. 16, 2025).

⁸ See, e.g., *id.* at 1-3.

⁹ See, e.g., *id.* at 3-4.

¹⁰ NERC, *2025-2026 Winter Reliability Assessment*, at 6 (November 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

¹¹ *Id.*

¹² E3, *Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results*, at 2 (Sept. 22, 2025), <https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20>

power supply shortfall in 2026.”¹³ E3 reported that nearly 9000 MW of new capacity will be needed in the region by 2030, but currently only 3000 MW of projects for new capacity are in active development.¹⁴ Overall, E3 found that “[p]referred resources such as wind, solar and batteries make only small contributions to meeting resource adequacy needs” and “[t]imely development of all resources is extremely challenging due to permitting and interconnection delays, federal policy headwinds, and cost pressures.”¹⁵

EMERGENCY SITUATION

The emergency conditions that necessitated the issuance of Order Nos. 202-25-11 and 202-25-11B continue, both in the near and long term.¹⁶ The production of electricity from Centralia will continue to be an asset to maintain reliability in the WECC Northwest region. According to the U.S. Environmental Protection Agency’s data, in 2025,¹⁷ Centralia generated an average of approximately 340,000 MWh per month, providing vital generation capacity to the region.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.¹⁸ NERC assessed that the WECC Northwest region is at high risk of energy shortfalls over the next five years,¹⁹ noting that “[r]apid forecasted demand growth is driving the need for more resources” and that “[p]eriods of unserved energy are projected for both summer and winter.”²⁰ The assessment notes that peak load in the region “is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest.”²¹ Additionally, while over 10 GW of new variable resources are in development, the assessment warns that “additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging.”²²

On February 25, 2026, a preliminary injunction was issued by the United States District Court for the District of Oregon that imposes operational constraints on the dams

WA%20RA%20Meeting.pdf. *See also id.* for the list of E3’s study sponsors, which include certain “regional utilities and generation owners.”

¹³ *Id.* at 10.

¹⁴ *Id.*

¹⁵ *Id.* at 2.

¹⁶ *See, e.g.*, Order No. 202-25-11 at 1.

¹⁷ *See Custom Data Download, EPA CAMPD (Clean Air Markets Program Data)*, <https://campd.epa.gov/data/custom-data-download> (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >> Apply >> “2025” and “January, February, March, April, May, June, July, August, September, October, November, December.” The data can then be filtered to only include the Centralia).

¹⁸ NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

¹⁹ *Id.* at 7.

²⁰ *Id.* at 8.

²¹ *Id.* at 19.

²² *Id.* at 19.

that comprise the Federal Columbia River Power System.²³ The restrictions imposed by the preliminary injunction will impact power and transmission system reliability, grid stability, and the ability to meet reserve requirements in the WECC Northwest assessment region.²⁴ The District Court did not give adequate consideration to the impacts that the preliminary injunction measures will have on the Bonneville Power Administration's (BPA) ability to provide reliable power and transmission services. BPA submitted several declarations detailing the impacts on reliability that would result from the preliminary injunction sought.²⁵ BPA's modeling of the operational measures in the motion for preliminary injunction concluded that the Columbia River System generation would be greatly decreased in March through November (nine months out of the year) and substantially increase the risk during time periods of high demand such as summer heat waves.²⁶ Indeed, there is a substantial increased risk that the regional power system will not be able to operate reliably under the ordered spill levels.²⁷

Order Nos. 202-25-11 and 202-25-11B were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."²⁸ The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."²⁹ In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid

²³ *National Wildlife Federation, et al. (NWF) v. National Marine Fisheries Service, et al. (NMFS)*, case 3:01-cv-00640 (D. Or. Feb. 25, 2026) (order granting preliminary injunction).

²⁴ Fed. Def. Response to Minute Order at 4-5, *NWF v. NMFS, et al.*, case 3:01-cv-00640 (D. Or. Feb. 24, 2026).

²⁵ See, e.g., Decl. of Rachel Dibble in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, case 3:01-00640, ECF No. 2574; Decl. of Audrey Stevenson in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, case 3:01-00640, ECF No. 2582.

²⁶ See Dibble Decl. ¶ 28; ¶ 42, fig. 3.

²⁷ See, e.g., Dibble Decl. ¶ 26; Stevenson Decl. ¶ 18.

²⁸ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

²⁹ *Id.*

technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”³⁰

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”³¹ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”³² This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Centralia Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes, businesses, and facilities critical to the national defense in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

³⁰ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

³¹ U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

³² Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Centralia Unit 2 shall be made available for operation through June 14, 2026.

Based on my determination of an emergency set forth above, I hereby order:

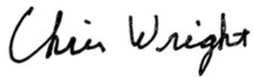
- A. From March 17, 2025, TransAlta shall take all measures necessary to ensure that Centralia Unit 2 is available to operate at the direction of either Gridforce Energy Management, LLC (in its role as Balancing Authority)³³ or Southwest Power Pool Western RC³⁴ (in its role as the Reliability Coordinator). Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices.
- B. To minimize adverse environmental impacts, this Order limits operation of Centralia Unit 2 to the times and within the parameters established in paragraph A. TransAlta shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Centralia Unit 2 has operated in compliance with this Order.
- C. All operations of Centralia Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By March 31, 2026, TransAlta is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Centralia Unit 2 consistent with this Order. TransAlta shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

³³ See EIA-930A 2024 Data, <https://www.eia.gov/electricity/gridmonitor/about>. On EIA-930A 2024 SCH 2, the BA Code for TransAlta Central Generation is GRID. See EIA-930 data reference tables, <https://www.eia.gov/electricity/gridmonitor/about>. On EIA-930 data reference tables BA Code GRID is associated with Gridforce Energy Management, LLC.

³⁴ See Southwest Power Pool RTO and Western RC Footprint with Planned Expansion map, <https://www.spp.org/documents/62914/rto%20and%20western%20rc%20footprint%20w%20planned%20expansion.png>.

- E. TransAlta is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. BPA is directed to facilitate transmission service, as needed, to effectuate this Order.
- G. This Order shall not preclude the need for Centralia Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Centralia Unit 2 shall not be considered a capacity resource.
- I. This Order shall be effective from March 17, 2026 through June 14, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 16th day of March 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Washington Utilities and Transportation Commission
Chairman Brian Rybarik
Commissioner Milt Doumit
Commissioner Ann Rendahl