UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

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]

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[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

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[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

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[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.

Chris Wright
Secretary of Energy

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

<u>Indiana Utility Regulatory Commission</u>
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)

ENERGYWIRE

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?

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

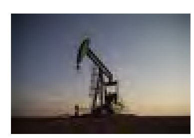

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Exhibit T: Congressional Research Service, *Federal Power Act: The Department of Energy's Emergency Authority* (June 12, 2025)

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

June 12, 2025

Congressional Research Service
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CRS REPORT
Prepared for Members and
Committees of Congress

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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.

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[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]

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[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.

Author Information

Ashley J. Lawson
Specialist in Energy Policy

Disclaimer

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

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

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[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

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[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

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[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] M*idcontinent 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 Assessment[21] and the 2023 – 2024 NERC Winter Reliability Assessment[22]) 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

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[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] M*idcontinent 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,

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[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. "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-reliabilityand-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

Chris Wright
Secretary of Energy

cc:

<u>FERC Commissioners</u>
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. 202-25-14

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.

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[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%

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[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-notices/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

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[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,

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[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-reliabilityand-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

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[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.

Chris Wright
Secretary of Energy

cc: **<u>FERC Commissioners</u>**
Chairman David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

<u>Pennsylvania Public Utility Commissioners</u>
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) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

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.

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

This document contains Confidential Attachments.

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

December 1, 2023

Hearing Exhibit 101
Direct Testimony and Attachments of Lisa K. Tiffin
Proceeding No. 23A-____E
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Attachment LKT-3	Phase II ERP Implementation Report Outline
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[1] ~~LKT-1 includes several attachments,~~ each of which are listed on page 5 the report.

I. <u>INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY AND RECOMMENDATIONS</u>

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

Electric Reliability Corporation ("NERC") Balancing Interchange and Transmission Operator certification.

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

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

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

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

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

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

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

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- 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

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

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

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

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

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

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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. <u>2023 ERP POLICY FRAMEWORK</u>

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

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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. <u>2020 ERP</u>

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

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

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

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

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

A: Yes. Fulfillment of each of these obligations is identified and described in the compliance matrix provided as ~~**Attachment A** to the ERP (**Attachment LKT-1**)~~. Attachment LKT-5

b. Key Objectives and Considerations

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

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

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

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

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

Q: HOW HAS TRI-STATE'S RESOURCE MIX CHANGED IN RECENT YEARS?

A: In 2016, Tri-State's system capacity consisted of 43 percent coal resources, 21 percent gas and oil resources, 12 percent firm contract non-renewable resources and 24 percent renewable resources. In 2022, Tri-State system capacity consisted of 34 percent coal resources, 19 percent gas and oil resources, 14 percent firm contract non-renewable resources and 33 percent renewable resources. By 2025, Tri-State anticipates 50 percent of the electricity its Members use will come from clean resources, in alignment with the REP. Tri-State has made progress and is continuing on its path to achieving an 80 percent reduction in GHG emissions regarding wholesale electricity sales in Colorado from a 2005 baseline by 2030 and 70 percent clean energy serving Member systems by 2030. The IRA Scenario forecasts an 89 percent reduction in GHG emissions regarding wholesale electricity sales in Colorado from a 2005 baseline in 2030 and approximately 70 percent clean energy serving Member systems by 2030.[2]

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

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

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

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[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. <u>Federal and State Legislation Impacting the 2023 ERP</u>

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

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that impact Tri-State's 2023 ERP.

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

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

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

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

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

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

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

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

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

d. <u>Stakeholder Engagement</u>

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

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

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

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

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

Q: HAS THIS APPROACH BEEN SUCCESSFUL?

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

IV. <u>2023 ERP: PLANNING PERIOD, ASSESSMENT OF EXISTING RESOURCES</u>

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

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

Q: PLEASE EXPLAIN THE SIGNIFICANCE OF THE RAP.

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

Commission rules.

Q: PLEASE EXPLAIN THE SIGNIFICANCE OF THE RPP.

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

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

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

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

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

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

A: As Tri-State approaches the end of the decade, a time when a significant amount of baseload power is anticipated to retire and renewable and semi-dispatchable resources are anticipated to come online to meet Colorado's emission reduction goals, there must be a plan in place for ensuring sufficient dispatchable replacement capacity to continue to meet Tri-State's Member load needs reliably. Tri-State's next ERP will not occur until 2027, and at that time, a Phase II would not be concluded with sufficient time to enable the permitting, procurement, and construction steps necessary to bring such resources online prior to the end of the decade. Planning for resources to be in place now for this unprecedented resource shift is essential to meeting reliability requirements.

Q: DID TRI-STATE CONSIDER A LONGER RAP?

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

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

A: Yes, there are two key changes in Tri-State's approach to the RAP. Tri-State's RAP in the 2020 ERP was limited to renewable and storage resources, and while the 2023 ERP will continue to seek procurement of those resources, it will also include opportunity for new innovative technologies[4] and address the need for a dispatchable natural gas resource. Also, Tri-State intends to leverage IRA funding to enable Tri-State to take significant steps forward in achieving its REP objectives during the RAP.

a. <u>Generation Capacity Needs</u>

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

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

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[4] *See* **Attachment** LKT-16 ~~**C-2** of the ERP Report (**LKT-1**)~~ for description of the innovative technology options being modeled in the 2023 ERP.

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

Q: PLEASE EXPLAIN THE PLANNING RESERVE MARGIN.

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

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

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

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

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

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

[6] *See* Proceeding No. 23A-0548E.

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

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

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

b. <u>Forecasted Resource Need</u>

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

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

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

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

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

V. <u>2023 ERP SCENARIO MODELING AND RESULTS</u>

a. <u>Modeling</u>

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

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

[7] Settlement Agreement, Section 3.11.12.

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

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

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

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

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

Base modeling assumptions for each scenario are identified in **Attachment** LKT-7 ~~B of the ERP Report (**LKT-1**)~~, with the assumptions unique to each scenario identified in **Attachment** LKT-10 ~~B-3 of the ERP Report (**LKT-1**)~~. Tri-State also conducted two sensitivity analyses on each scenario, including:

1. Extreme Weather Event ("EWE") Analysis; and
2. High Gas ("HG") Analysis.

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

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

A: Yes, pursuant to Section 3.11.14 of the 2020 ERP Settlement Agreement, Tri-State convened stakeholder meetings to discuss 2023 ERP Phase I scenarios and modeling assumptions, including retirement date windows to be modeled for certain coal units. These meetings also served to address the Commission's request in Decision No. C23-0437[8] to "…work with interested parties to refine modeling assumptions and practices in an attempt to forge as great a degree of consensus as possible, by using its model to analyze the benefits and costs associated with various retirement dates for Craig Unit 3, including identifying economically optimal retirement dates as part of the direct case in its 2023 ERP."

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

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

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

retirement. Without these resources ESPV3 relies on an estimated penalty[9] related to the third-party sale which impacts the affordability of the scenario and drives the Springerville 3 retirement date selected in the ESPV3 scenario to the latest date the model was given.[10] Despite having more aggressive Colorado or system emissions reductions, ACER and SWER Scenarios have less Colorado GHG reductions by 2030 than the IRA Scenario.

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

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

A: Yes. In every scenario modeled, the retirement date for Craig 3 is January 1, 2028. This is a change from the 2020 ERP. Decision No. C23-0437[11] 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** LKT-10 ~~B-3 of the ERP Report (**LKT-1**~~).

[11] ¶ 77, Proceeding No. 20A-0528E.

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

b. Preferred Plan: IRA Scenario

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

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

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

A: The IRA Scenario retires 1,207 MW (nameplate – 1,067 net MW) of coal-fired generation during the RAP. Under the IRA Scenario, if USDA funding is received as requested and if contractual commitments are adequately addressed, Tri-State intends to announce a retirement date of 2031 for the coal-fired Springerville Station Unit 3 (458 MW nameplate capacity). This is a dramatic acceleration from its expected operating life of 2066. Additionally, the IRA Scenario further accelerates the retirement date for coal-fired Craig 3 (535 MW nameplate capacity) by two years, to 2028. The IRA Scenario also adds 1,250 MW of renewables and storage between 2024 and 2031, 1,040 MW of those projects are anticipated through PPAs, with 210 MW being build-transfer arrangements. Lastly, the IRA Scenario continues to select a 290 MW dispatchable, natural gas combined-cycle plant for 2028, with conversion to carbon capture and storage capability in 2031. This set of ambitious, near-term resource plan actions is predicated on Tri-State receiving New ERA Funding as requested.

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

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

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

If financially viable through direct pay tax credits, Tri-State may still elect to pursue the approximately 10 MW iron air battery storage project for 2026 without 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.

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

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

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

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

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

VI. <u>2023 ERP PERFORMANCE METRICS</u>

a. <u>Reliability</u>

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

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

- Level I:
  - Planning Reserve Requirement ("PRM") of 22 percent, transitioning to 30.5 percent upon the retirement of Craig Station, based upon the third-party ELCC and PRM Study (**Attachment** LKT-15 ~~G-1 of the ERP Report (**LKT-1**)~~);
  - Loss of load hours ("LOLH") of no more than 1 day in 10 years;
    - 2.4 hours per year 2024 to 2033;
    - 24 hours total 2034 to 2043; and
  - No more than 0.4 GWh annually of expected unserved energy ("EUE").
- Level II:
  - No more than 12 hours of EUE in 12 EWE from 2026 to 2031;
  - No more than 3 hours of expected unserved energy in any year during EWE event periods 2026 to 2031; and
  - EUE in any EWE hour cannot exceed 20 percent of load in that hour.

Level I metrics set a baseline that ensures Tri-State resources will meet industry-standard service reliability requirements and Level II metrics provide an added level of assurance of resource adequacy under potential EWE conditions, which are becoming more frequent and extreme. The Commission acknowledged in Decision No. C23-0437 that "…history may not be fully predictive of future weather extremes given climate change…"[13]

Q: HOW WERE THE RELIABILITY METRICS DEVELOPED?

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).

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

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

A: First and foremost, Tri-State is a Load Responsible Entity ("LRE") meaning it must maintain capacity to meet its load and planning reserve needs. Even as a future Market Participant in SPP RTO in the western interconnection, Tri-State will continue to be responsible for its performance obligation as an LRE. Each LRE is required to maintain the total of planning capacity necessary to serve Net Peak Demand (load) and PRM. This is consistent with the 2020 ERP Settlement Agreement at section 3.11.14. which describes certain elements of "Tri-State's Next ERP Filing," which commits that "reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access." 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. <u>Financial Results</u>

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

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

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

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

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

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

A: To support necessary generation investments in the coming years and to assist in alleviating the impact of stranded assets due to coal unit retirements, Tri-State submitted a Letter of Interest to the USDA on September 13, 2023 seeking to 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.

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

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

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

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

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

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

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

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

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

c. <u>Environmental Compliance</u>

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

A: Under the 2020 ERP Settlement Agreement, Tri-State committed that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its Colorado Air Pollution Control Division ("APCD") verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): a twenty-six percent (26 percent) reduction in calendar-year 2025; a thirty-six percent (36 percent) reduction in calendar-year 2026; and a forty-six percent (46 percent) reduction in calendar-year 2027.[18] Tri-State also agreed that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD verified 2005 Baseline, an eighty percent (80 percent) reduction in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado in calendar-year 2030 ("the 2030 Emissions Reduction").[19]

The Interim-Year Emissions Reductions and 2030 Emissions Reduction will be calculated and reported consistent with the methodology adopted by APCD for the Verification Workbook.[20] In each year following a year in which Tri-State has committed to emissions reductions, Tri-State will report the results of emissions reductions in its ERP Annual Progress Report (the "Annual Progress Report") submitted to the Commission under Rule 3618.[21]

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[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.

Q: PLEASE EXPLAIN THE VERIFICATION WORKBOOK.

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

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

The Workbook provides the basis for the APCD to perform emission reductions verification, as well as a high level of transparency while also providing clarity and certainty an ERP evaluation. Further, the Workbook establishes carbon 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** LKT-18 ~~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

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Partial Requirements in Colorado. The reduced load forecast[22] for the planning period starting in 2025 (Member exits) and 2026 (Partial Requirements) results in a need to correspondingly adjust the 2005 Baseline in the Workbooks. Upon those Colorado Member exits and implementation of Partial Requirements elected by Colorado Members, Tri-State will no longer be responsible for emissions and emissions reductions associated with those loads. The 2005 Baseline used for determination of emissions reductions for 2025 adjusts for the Member exits only, as the Partial Requirements contracts are not anticipated to begin until 2026. Partial Requirements Members can select MAX (Firm capacity) or MARS (intermittent resource) options, where only the MAX selections reduce the system capacity that Tri-State is responsible – currently forecasted as 163 MW, 86 MW of which is related to Members in Colorado. The Workbook accounts for the impacts of 117 MW of the MARS option as a renewable resource.

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

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

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[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."

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

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

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

VII. <u>RESOURCE ACQUISITION PLAN</u>

Q: WHAT SIGNIFICANT ELEMENTS OF TRI-STATE'S ACQUISITION APPROACH ARE NEW FOR THE 2023 ERP?

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A: In the 2020 ERP Phase II, Tri-State utilized a single RFP for renewable and storage PPA resources only for the 2025-26 period, indicating Tri-State did not intend to pursue self-build or ownership options for resources at that time[23] and agreeing to a limited procurement window[24] given load uncertainties and its capacity-long position. The 2020 ERP Phase II procurement and modeling process resulted in identification of the need to procure only one 200 MW wind resource within that two-year period.

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

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

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[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.

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

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

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

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

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

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

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

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

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

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

Q: WHAT ACQUISITION PROCESS IS TRI-STATE PROPOSING FOR THIS 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.

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

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

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

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

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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.

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VIII. <u>Organized Market Participation</u>

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.

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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** LKT-7 ~~B of 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 to be resource-long until 2029. With the resource additions planned under the IRA Scenario, our resource-long position will extend through the planning period.

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

A: First, Member load has declined due to Member exits and Partial Requirements. Second, the capacity contribution from renewable resources has declined due to the ELCC and PRM Study results (**Attachment** LKT-15 ~~**G-1** of the ERP Report (**LKT-1**)~~). Additionally, coal resource retirements occur during the RAP that result in firm capacity reductions.

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

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

X. CONCLUSION

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

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

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

PROCEEDING?

A: Tri-State requests Commission approval of the proposed Phase II timeline, Phase II RFPs, Bid Policy, IE SoW, Model PPAs and Term Sheets, Implementation Report outline, 45-Day Report approach, and RAP Action Plan. Tri-State also requests that the Commission approve its proposal to model no more than eight Phase II portfolios[27] to be modeled, two of which will be identified through informal discussions with stakeholders prior to the start of Phase II.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

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

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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: [signature]
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

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ATTACHMENTS

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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
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Attachment LKT-11	Ancillary Services
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Attachment LKT-20HC	Inflation Reduction Act (IRA) - Executable
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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)
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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
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Attachment LKT-29	ELCC and PRM Study (Astrape)
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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. 202-25-14

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)

~~Hearing Exhibit 101~~
~~Attachment LKT-1 - Redline~~
~~Proceeding No. 23A-0585E~~
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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

123055698.2

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Attachment LKT-32	Reliability Evaluation

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 (“CO_2”) 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~~ LKT-5 to this report identifies the components of this report and 2023 ERP Phase I filing that comply with Commission directives.

The 20-year[2] resource planning period (RPP) for the 2023 ERP is 2024-2043 and the resource acquisition period (RAP) is the six-year[3] 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 (PVRR), 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.

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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 period[8], 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).

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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]	~~2826~~2815	~~2736~~2725	~~2516~~2505	~~2560~~2549	~~2733~~2722	~~2801~~2790	~~2827~~2816	~~2846~~2835	~~2897~~2797	~~2927~~2827
Excess (MW)	~~398~~409	~~561~~572	~~697~~708	~~656~~667	~~84~~95	~~-68~~-57	~~-82~~-71	~~-99~~-88	~~-143~~-43	~~-180~~-80

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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.

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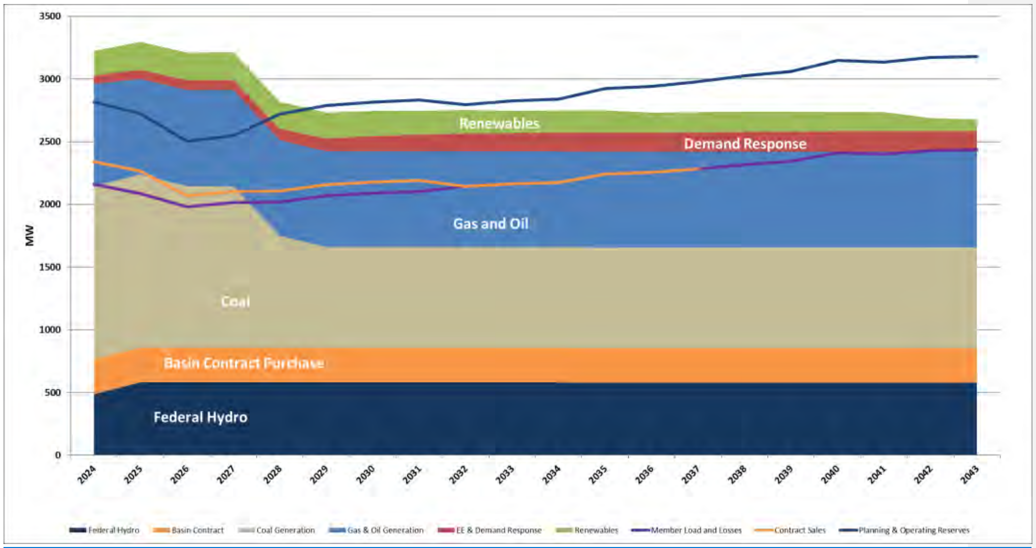

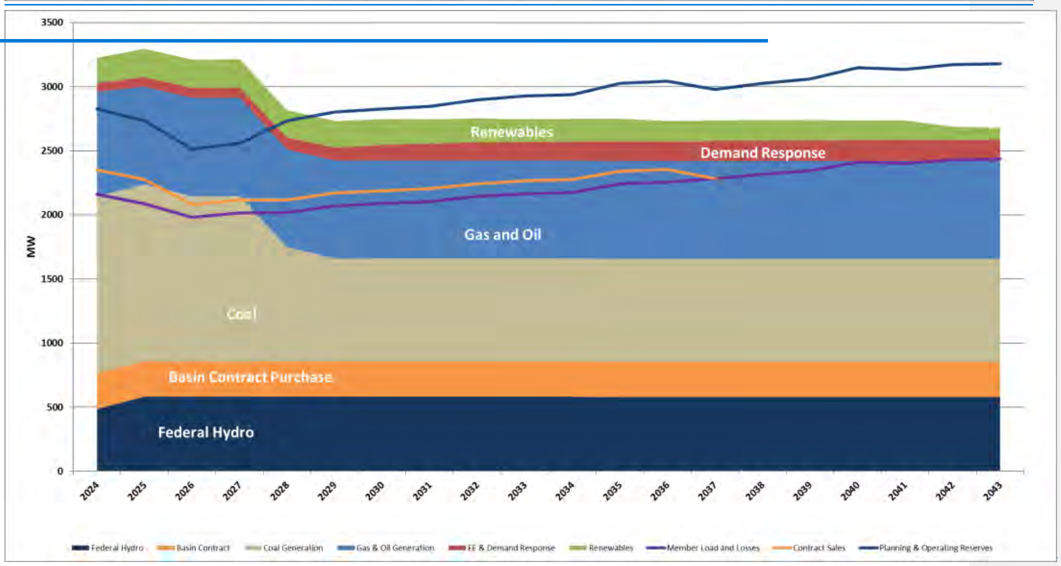

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Table 2: Load & Resources (L&R), IRA Scenario

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3303	~~3286~~3276	~~3291~~3281	~~3210~~3201	~~3193~~3184	3332	~~3458~~3448	~~3134~~3124	~~3134~~3124
Total Obligations (MW)[12]	~~2826~~2815	~~2970~~2959	~~2750~~2739	~~2794~~2783	~~2733~~2722	~~2801~~2790	~~2827~~2816	~~2846~~2835	2997	3027
Excess (MW)	~~398~~409	~~333~~344	~~536509~~37	~~498509~~499	~~477~~4878	~~392403~~393	~~504515~~06	~~612~~6213	~~137~~127	~~107~~97

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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.

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Figure 2: Load & Resources (L&R), IRA Scenario

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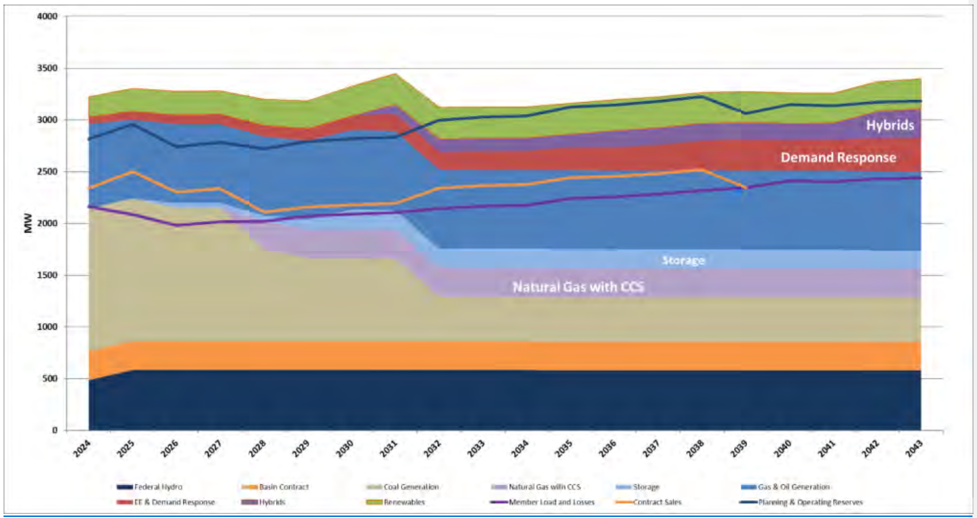

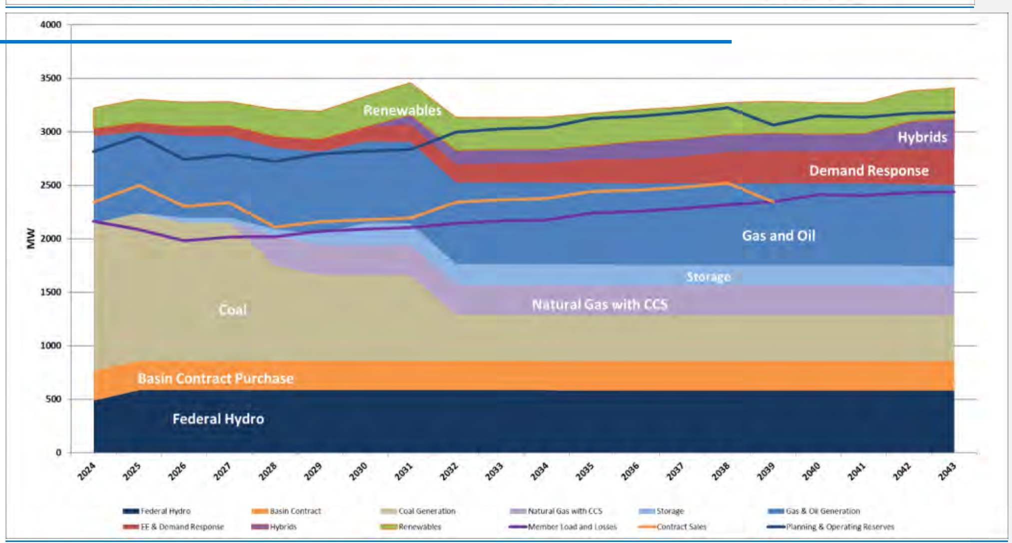

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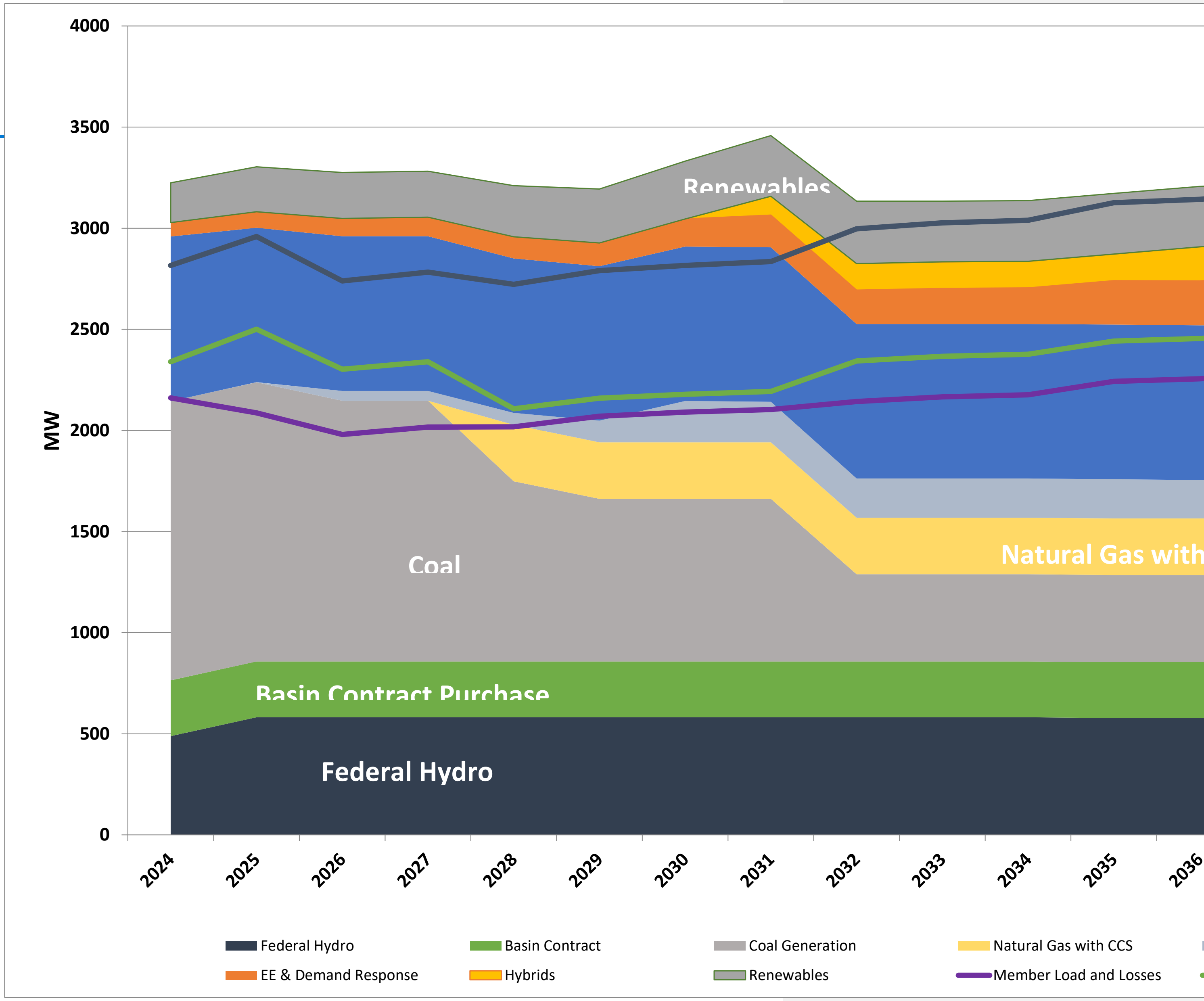

[13] Commission Rule 3605(a)(IV)(O).

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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 LKT-17 ~~C-3.~~ Resources capable of self-supplying certain ancillary services are identified in Attachment LKT-11 ~~B-4.~~ Information on Tri-State's PPA and contract resources is provided in Attachment LKT-15 ~~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 LKT-30 ~~G-2~~).

Electric Energy and Demand Forecast

Attachments LKT-26 and LKT-27 ~~F and F-1~~ 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, two[14] 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 LKT-12 ~~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 LKT-25~~E.~~

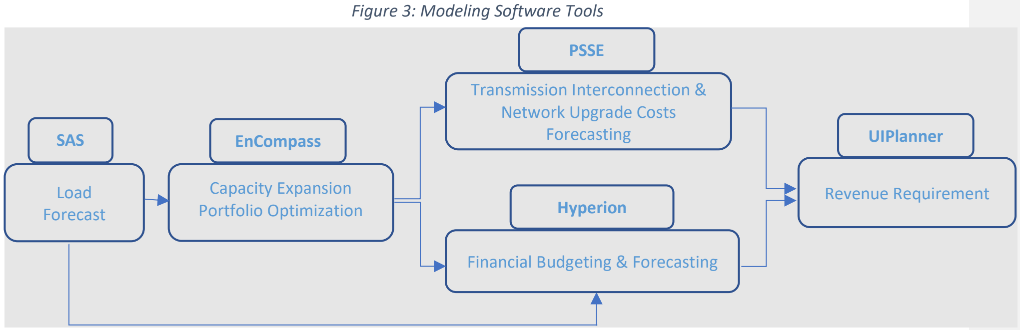
The Tri-State system is modeled as four planning regions. The planning regions are not state boundary restricted, rather they reflect significant power flow constraints within the Tri-State system:

- 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 LKT-13~~B-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[16] and reflecting the Tri-State system topology, provided as Attachment ~~B-6~~ 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[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 MROW[19] 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 ~~G-1~~LKT-29) 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.

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    - 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).
    - 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.
    - 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 hour[27]
- 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.

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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).

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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 PVRRs 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

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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 RFP[34]
2. February 16, 2023: Beneficial Electrification (BE) Meeting #1[35]
3. February 23, 2023: Phase I Storage Valuation, ELCCs, DSM/DR/BE,[36] and Scenarios/Sensitivities[37]
4. March 10, 2023: Phase I Scenario and Sensitivity Planning #1[38]
5. March 14, 2023: Phase I Reliability and Extreme Weather Event (EWE) Sensitivities
6. March 22, 2023: BE Meeting #2[39]
7. March 24, 2023: Phase I Reliability and Extreme Weather Sensitivities
8. March 27, 2023: Phase I Scenario and Sensitivity Planning #2[40]
9. April 24, 2023: Phase I Battery Modeling and ELCC Study[41]
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 Feedback[43]
13. July 19, 2023: Phase I PRM, ELCC, and EWE Modeling[44]
14. August 14, 2023: Phase I Scenario and Sensitivity Planning #4[45]
15. September 27, 2023: Phase II Planning[46]
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 website[48] in advance of the meetings and were open for public participation.[49]

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[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)

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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 PVRRs 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 PVRRs

Error! Reference source not found.~~Table 8~~ identifies the PVRRs resulting from each scenario modeled, over the RPP.

Table 8: PVRR by Scenario

Scenario	PVRR ($, Millions)
Scenario 1: BAU	$17,507.40
Scenario 2: IRA	$176~~6~~,221~~352~~.4~~0~~0
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.

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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]

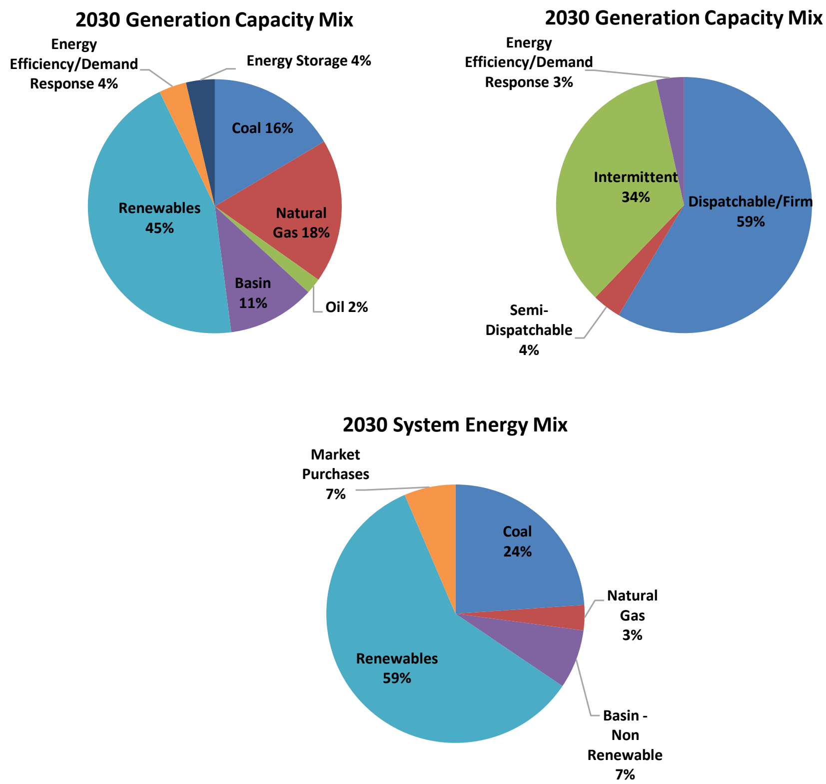
Table 10: Modeled Retirements (Scenario 1 – BAU)

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.

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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)	CH4 (MT CO2e)
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)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 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.

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Year	CO_2 [65] (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
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.

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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

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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 (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.

[68] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

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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**

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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	

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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.

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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:
  - 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 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.

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2. Inflation Reduction Act of 2022 (IRA) Scenario

Assumptions unique to each scenario are identified in Attachment LKT-10 ~~B-3.~~

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.

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- 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.

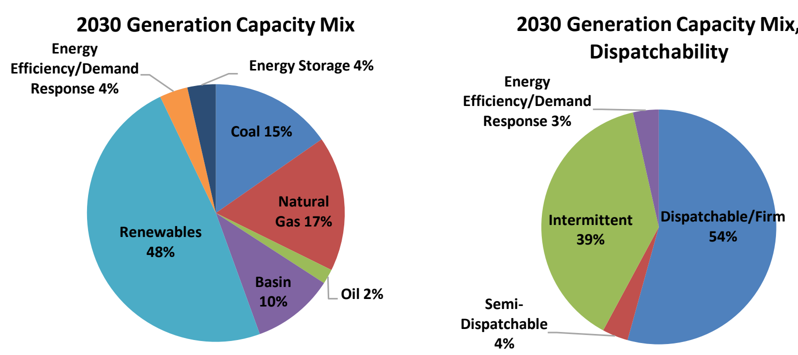
Unit retirements modeled are shown in the following table.[75]

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)(I)(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.

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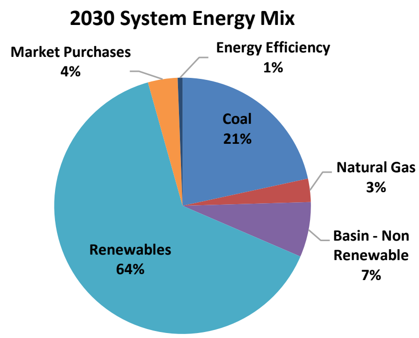

Table 31: Projected Annual Capacity Factors for Thermal Resources (Scenario 2 – IRA)

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

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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)	CH4 (MT CO2e)
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)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 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.

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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

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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 (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.

[82] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

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Table 37~~373736~~: 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
	$17,221.4~~16,352.0~~	$10,726.7	$733.1	$27,948.1~~27,078.7~~	$28,681.2~~27,811.8~~
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.

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*Table 39: Total Financial Under **EWE** Sensitivity (Scenario 2 – IRA)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,166.8~~16,300.1~~

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**

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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	

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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.

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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~~Table 46~~ 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~~Table 47~~ 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.

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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:
    - 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 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)

Assumptions unique to each scenario are identified in Attachment LKT-10~~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.

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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").

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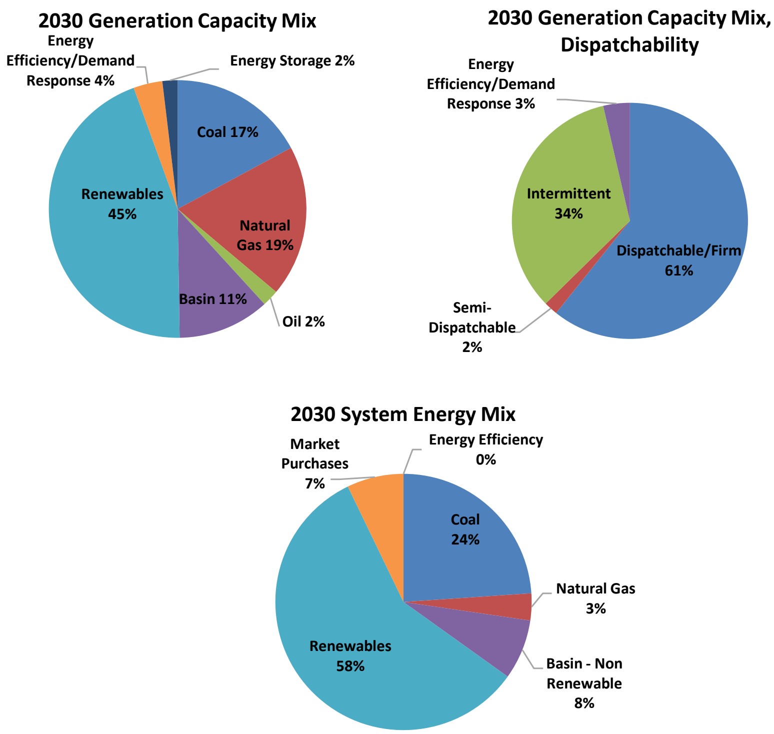
Figure 6: Projected Tri-State System Resource Mix 2030 (Scenario 3 – ESPV3)[90, 91, 92]



[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.

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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)	CH4 (MT CO2e)
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)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 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.

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Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
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.

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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.

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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

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Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 59~~XX~~: Total Financial Under **EWE** Sensitivity (Scenario ~~1~~3 – ~~BAU~~ESPV3)*

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Scenario PVRR ($, Millions) (2023 WACC 4.12%)

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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 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**

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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)					

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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

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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

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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.

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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.

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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.

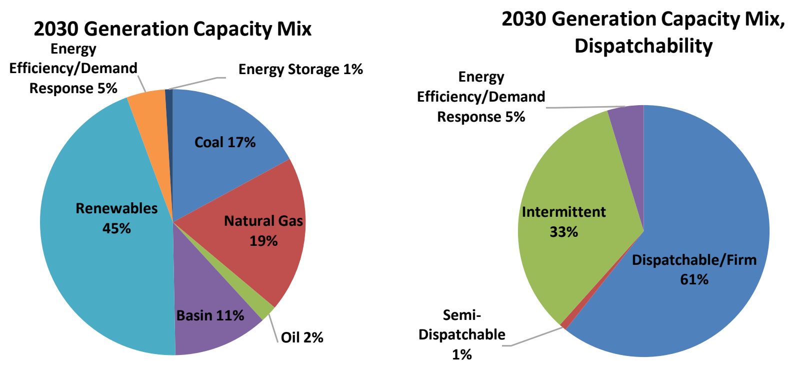
Unit retirements selected in the modeling are shown in the following table.[103]

Table 70: 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)(I)(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.

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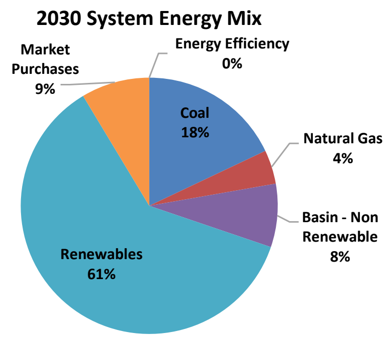

Table 71: Projected Annual Capacity Factors for Thermal Resources (Scenario 4 - SWER)

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

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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)	CH4 (MT CO2e)
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)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 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.

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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

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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.

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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				

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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 80~~XX~~: Total Financial Under **EWE** Sensitivity (Scenario 4 – SWER)*

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Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,~~275.6~~315.4

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**

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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	

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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)

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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 LKT-29 ~~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.

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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:
  - NM Market HE 2 to HE 6 and HE 11 to 15

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    - 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 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.

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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)(I)(I).
[115] 2020 ERP Settlement Agreement at Section 3.11.6.

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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.

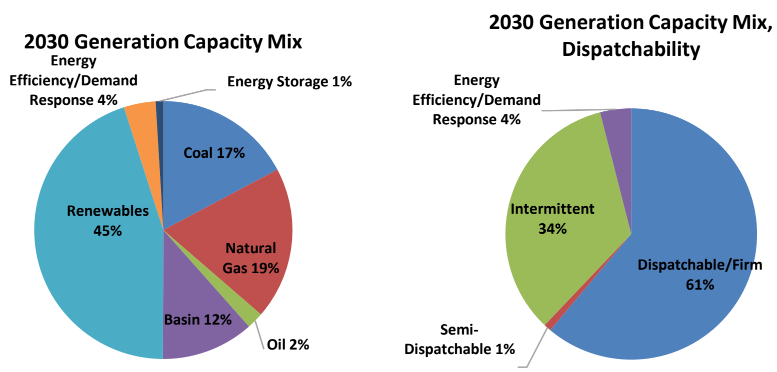
Unit retirements selected in the modeling are shown in the following table.[118]

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)(I)(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.

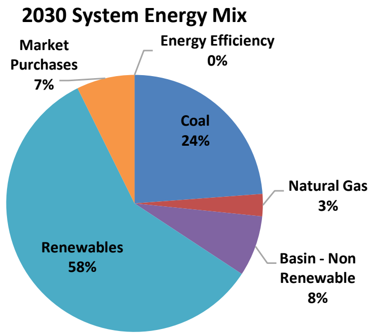


Table 92: Projected Annual Capacity Factors for Thermal Resources (Scenario 5 - ACER)

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

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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)	CH4 (MT CO2e)
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)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 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.

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Table 95: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 5 - 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

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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.

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[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.

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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%)
$17,180.6

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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 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	

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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 LKT-29 ~~G-1~~) and ELCCs continue to decline with the addition of intermittent resources. In Scenario

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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.

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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

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:
  - July 12, 2042 HE2, 40 MW; and
  - 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:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth

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- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

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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 CO_2 and CH_4 emissions in 2025 and 2030.

Figure 9: Comparison of Forecasted CO_2 Emissions in 2025 and 2030, by Scenario

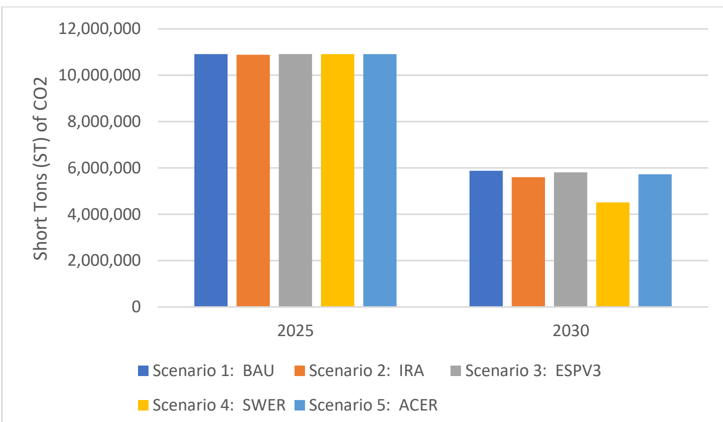
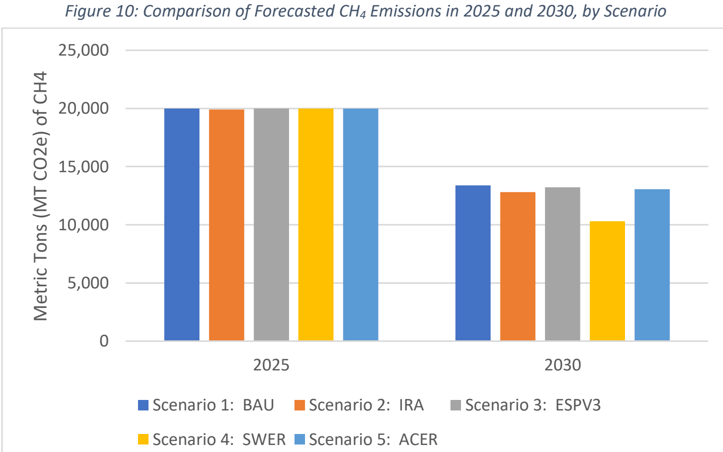


Figure 10: Comparison of Forecasted CH_4 Emissions in 2025 and 2030, by Scenario



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 CO_2 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 LKT-10 ~~B-3~~ 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 PVRRs 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

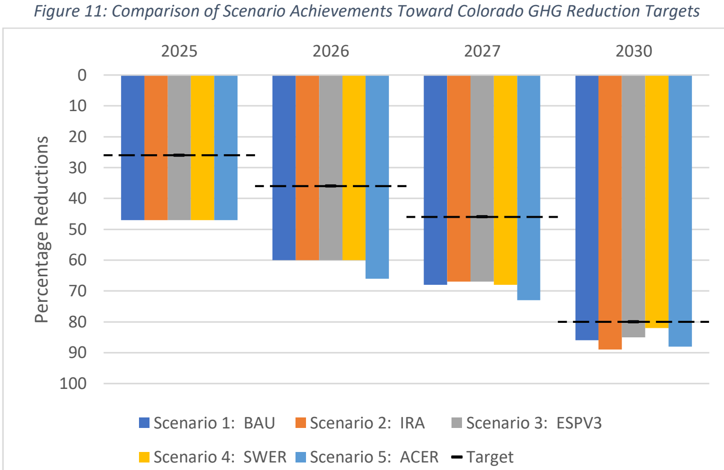


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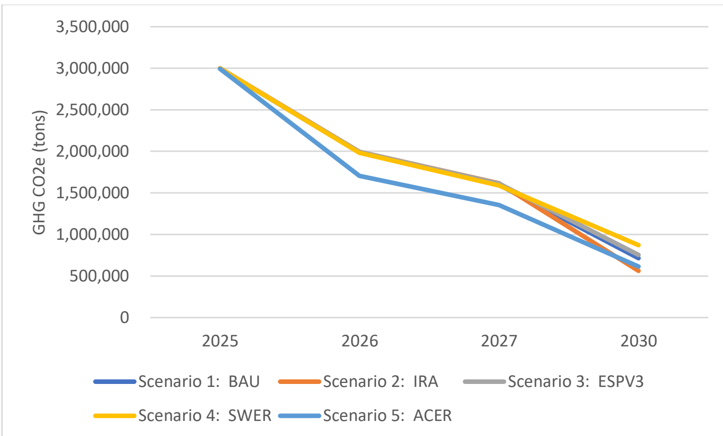
Figure 12: Comparison of Colorado CO2e



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.

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Figure 13: Comparison of SCoC

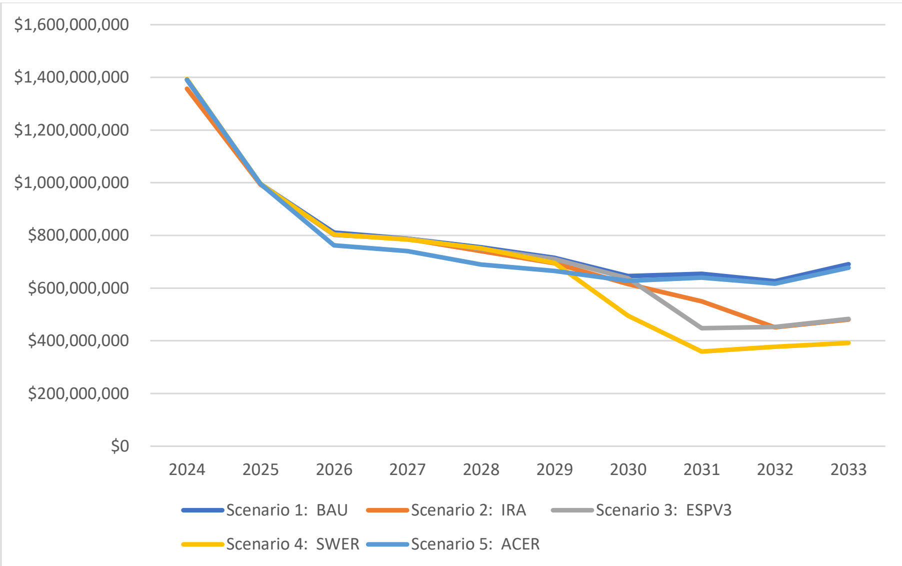
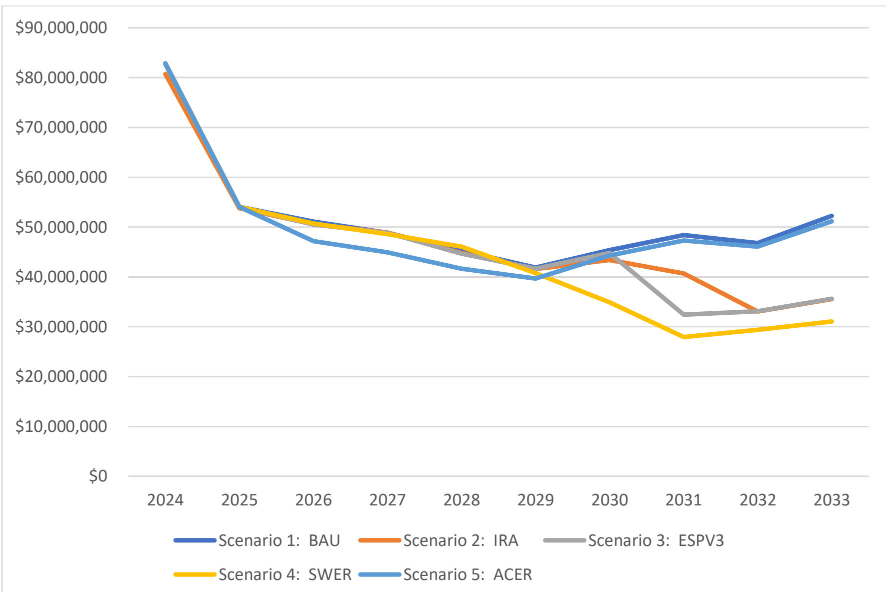


Figure 14: Comparison of SCoM



Financial Analysis

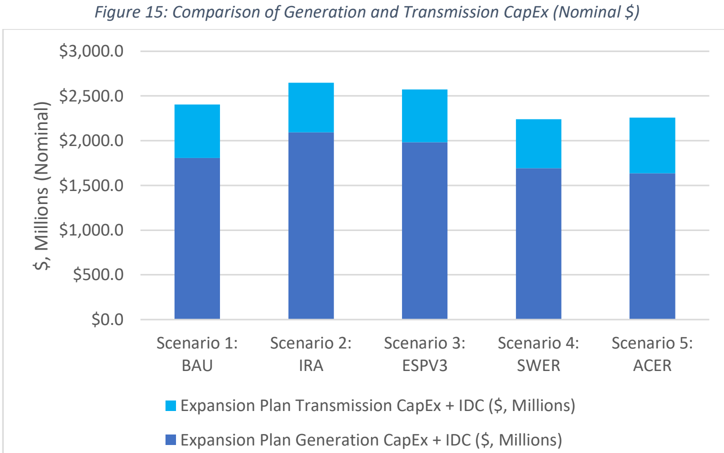
The following table compares total financial results for each scenario, both with and without the SCoC and SCoM. Scenario 2 (IRA) is one of the lowest cost plans on a PVRR basis, and has the lowest renewable curtailment costs during the RAP. ~~Scenario 2 (IRA) also has the lowest PVRR when SCoC and SCoM are included.~~ Scenario 2 (IRA) exceeds Colorado GHG reduction target for 2030, while maintaining reliability and affordability—which best serves Tri-State Members.

Table 111~~111107~~: Comparison of PVRR

	PVRR ($, Millions)	PVRR w/SCoC and SCoM ($, Millions)
Scenario 1: BAU	$17,507.4	$29,916.4
Scenario 2: IRA	$17~~6~~,221~~352~~.4~~0~~	$28~~7~~,688~~81~~1.2~~8~~
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)

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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~~Table 109~~ 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

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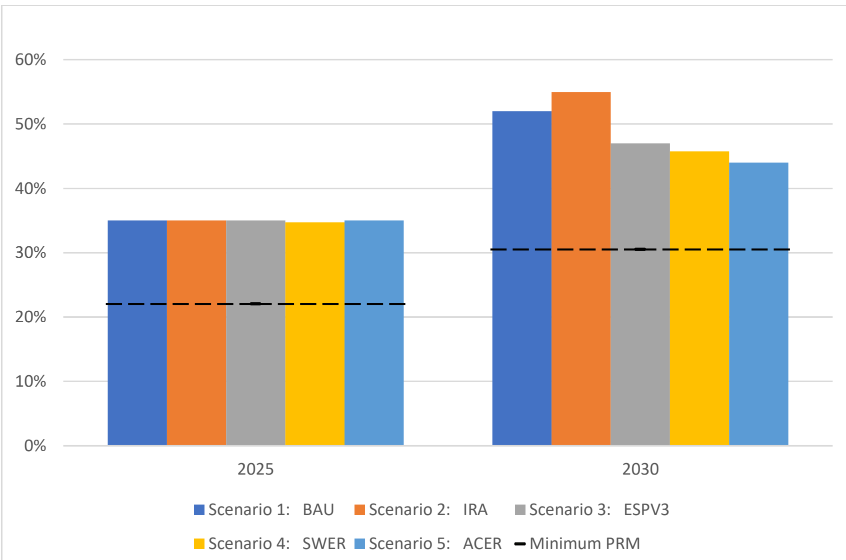
Reliability Analysis

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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List of Tables and Figures

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

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.

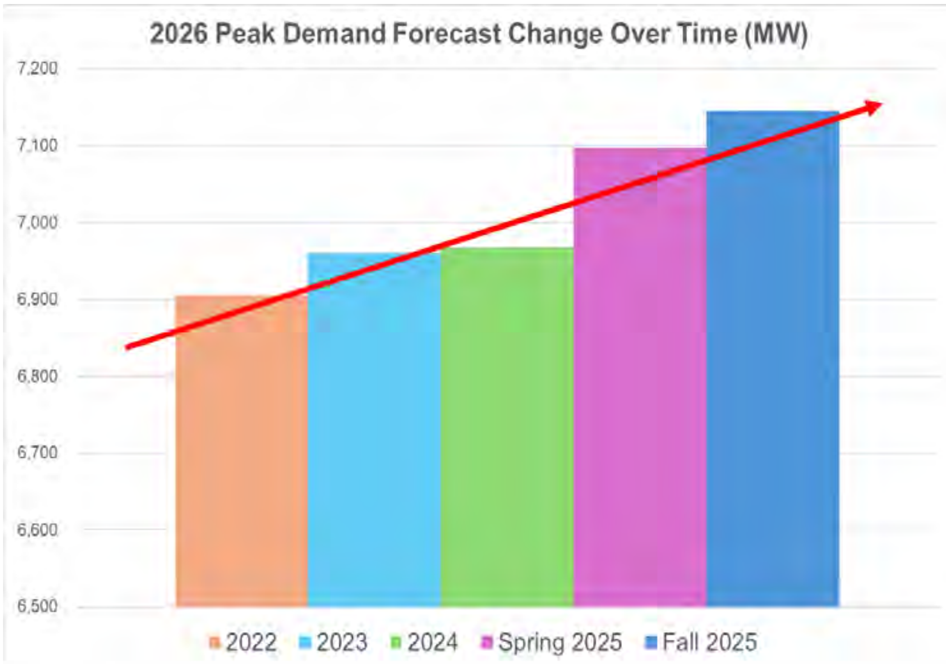
A. Comanche Unit 3 Outage and the Need for Comanche Unit 2 in 2026

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

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[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.

Process Step	***Timing***
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.

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[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,

PHILIP J. WEISER
Attorney General

/s/ Paul J. Kyed
Justin Cox, #58570*
Assistant Attorney General
Aileen Chong, #56439*
Assistant Attorney General
Paul J. Kyed, #37814*
First Assistant Attorney General
Revenue & Regulatory Law Section

Attorneys for Trial Staff of the Public Utilities Commission

Ralph L. Carr Colorado Judicial Center
1300 Broadway, 8th Floor
Denver, Colorado 80203
Telephone: (720) 508-6743 (Cox)
Telephone: (720) 508-6330 (Chong)
Telephone: (720) 508-6332 (Kyed)
Email: Justin.Cox@coag.gov
Email: Aileen.Chong@coag.gov
Email: Paul.Kyed@coag.gov
*Counsel of Record

PHILIP J. WEISER
Attorney General

/s/ Jessica L. Lowrey
*JESSICA L. LOWREY, #45158
First Assistant Attorney General
*GABRIELLE FALCON, #56739
Assistant Attorney General
Natural Resources and Environment Section
1300 Broadway, 7th Floor
Denver, CO 80203
Telephone: 720.508.6167 (Lowrey)
720.508.6185 (Falcon)
Email: jessica.lowrey@coag.gov
gabby.falcon@coag.gov
*Attorneys of Record

Counsel for the Colorado Energy Office

PHILIP J. WEISER
Attorney General

/s/ *Thomas F. Dixon*
Thomas F. Dixon, Reg. No. 500
First Assistant Attorney General
Patrick Witterschein, Reg. No. 58184
Assistant Attorney General
Office of the Attorney General
1300 Broadway, 9th Floor
Denver, Colorado 80203
(720) 508-6214 / thomas.dixon@coag.gov
(720) 508-6807 / patrick.witterschein@coag.gov

ATTORNEYS FOR THE COLORADO OFFICE OF THE UTILITY CONSUMER ADVOCATE

/s/ Christopher M. Irby
Christopher M. Irby, #35778
Assistant General Counsel
Xcel Energy Services, Inc.
3500 Blake Street
Denver, Colorado 80205
Phone: 303-285-3537 (Irby)
Fax: 303-294-2988
E-mail: christopher.m.irby@xcelenergy.com

and

Matthew S. Larson, #41305
Samuel D. Eisenberg, #56951
Wilkinson Barker Knauer, LLP
2138 W. 32nd Ave, Suite 300
Denver, Colorado 80211
Telephone: (303) 626-2350 (Larson)
(303) 626-2345 (Eisenberg)
Fax: (303) 568-6663
Email: mlarson@wbklaw.com
seisenberg@wbklaw.com

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
____
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.

KRISTEN DIAZ
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20244015138
MY COMMISSION EXPIRES 04/18/2028

Kristen Diaz
____
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) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

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.

Contents

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.

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[1] 2024 APR: 11 MW need projected stating 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 1[2] is planned to cease operations by December 31, 2025, Craig Unit 3 will retire January 1, 2028, and Craig Unit 2[3] 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]

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[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

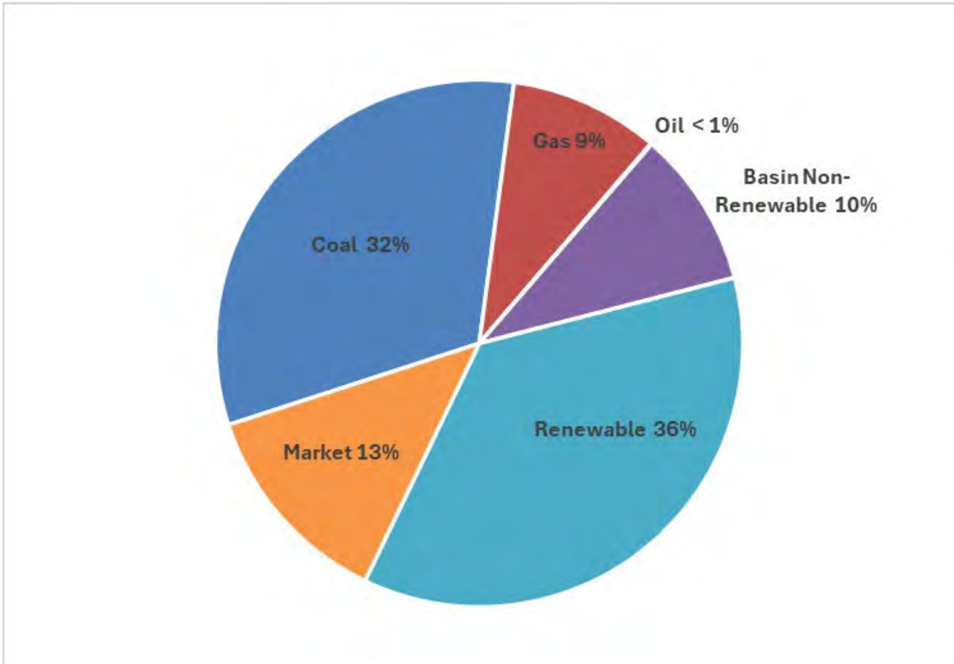
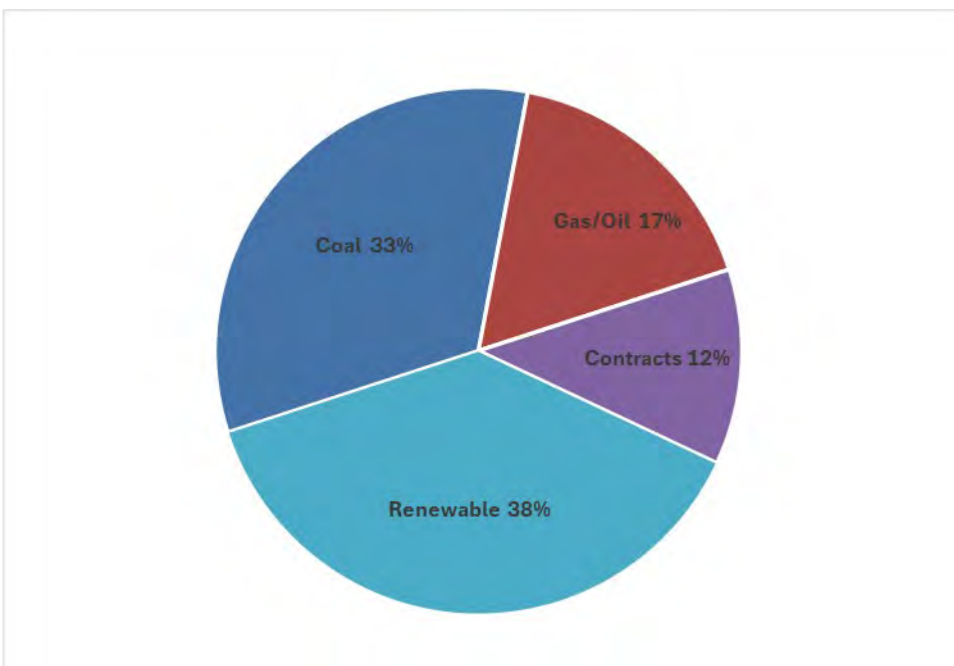


FIGURE 2 – 2024 CAPACITY PORTFOLIO



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.

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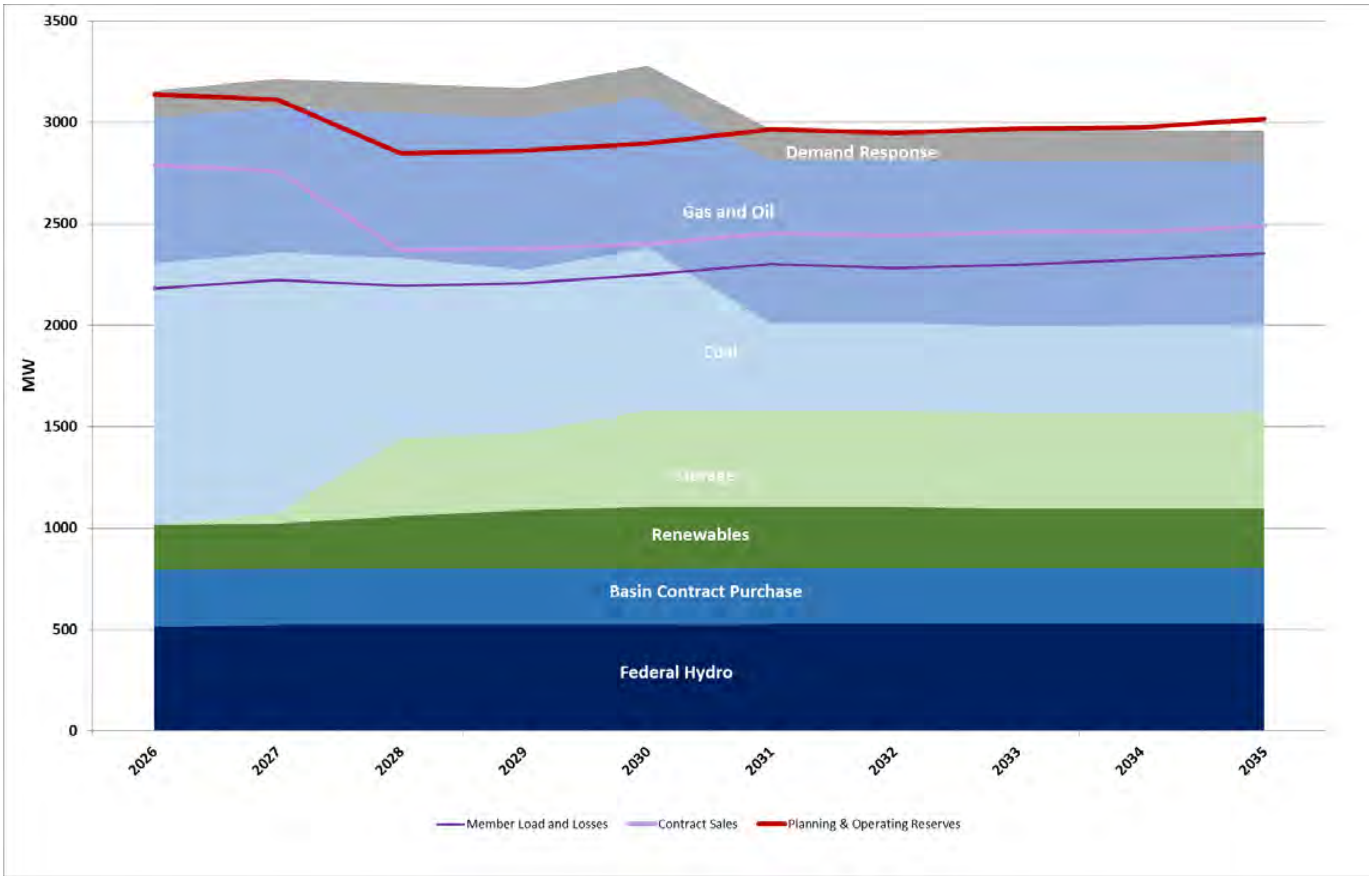
[6] LKT-1 - Attachment G-1 - Confidential - ELCC and PRM Study (Astrape) filed December 1, 2023 in Proceeding No. 23A-0585E.
[7] Response Comments of Tri-State Generation and Transmission Association, Inc., Proceeding No. 25A-0266E.

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:

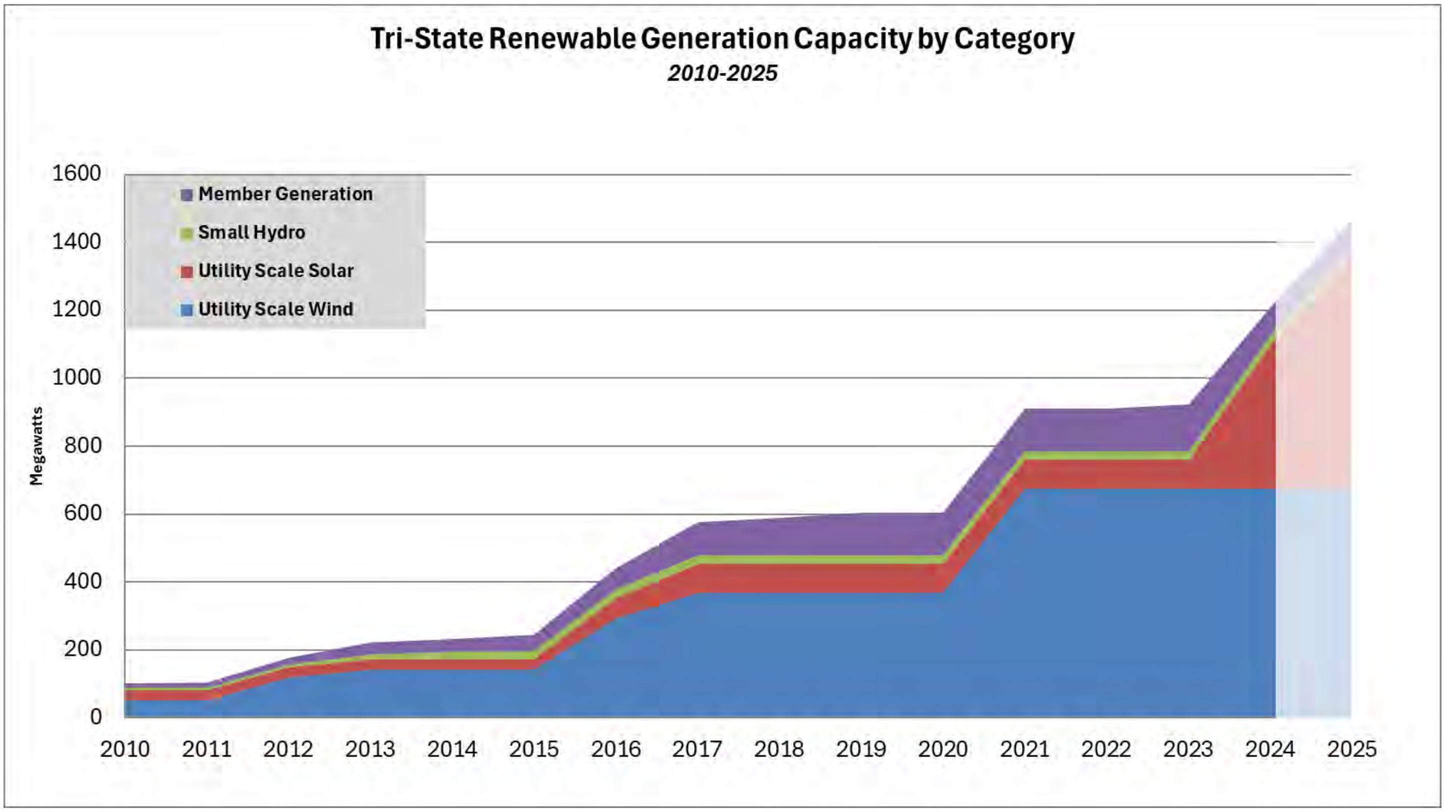
- High Country Energy Station 2 (Montrose County, CO), 50 MW, Q2-2027 COD;
- Oso Negro Energy Storage (Bernalillo County, NM), 100 MW, Q2-2028 COD;
- Morel Energy Storage (Moffat County, CO), 200 MW, Q1-2030 COD;
- Carousel Energy Storage (Kit Carson County, CO), 150 MW, Q4 2027 COD; and
- Arriba Wind (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 CAPACITY[16]



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

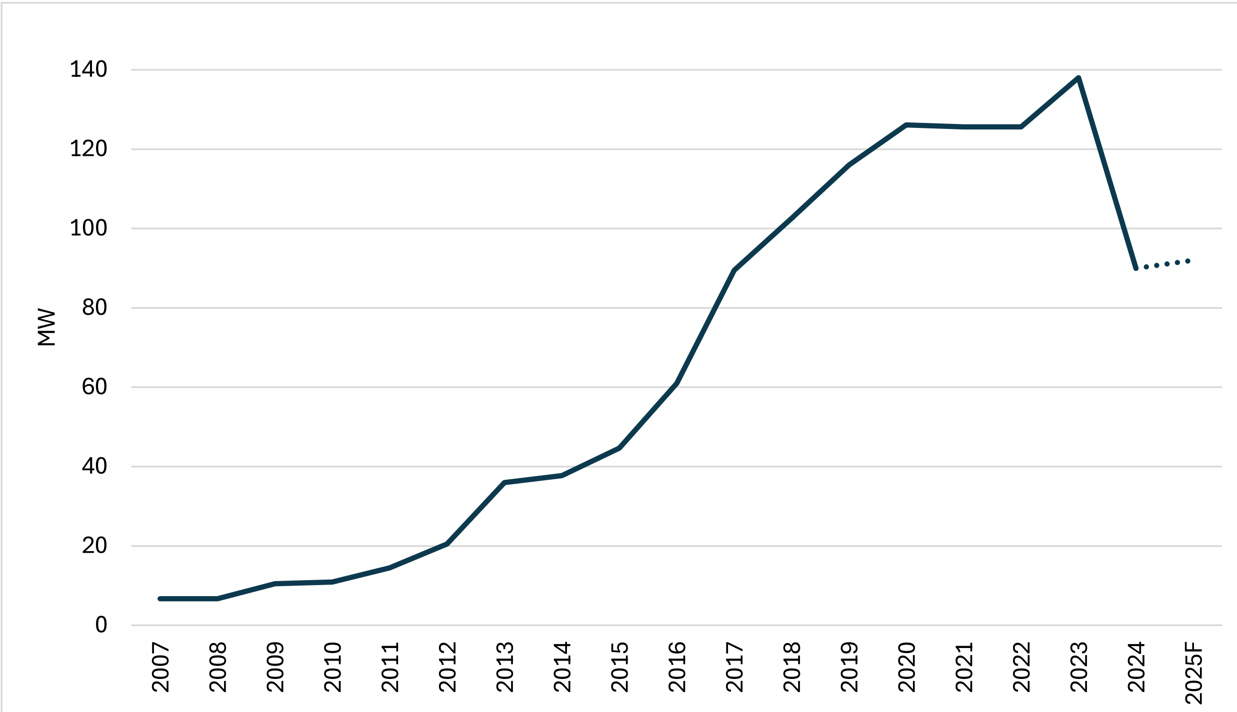
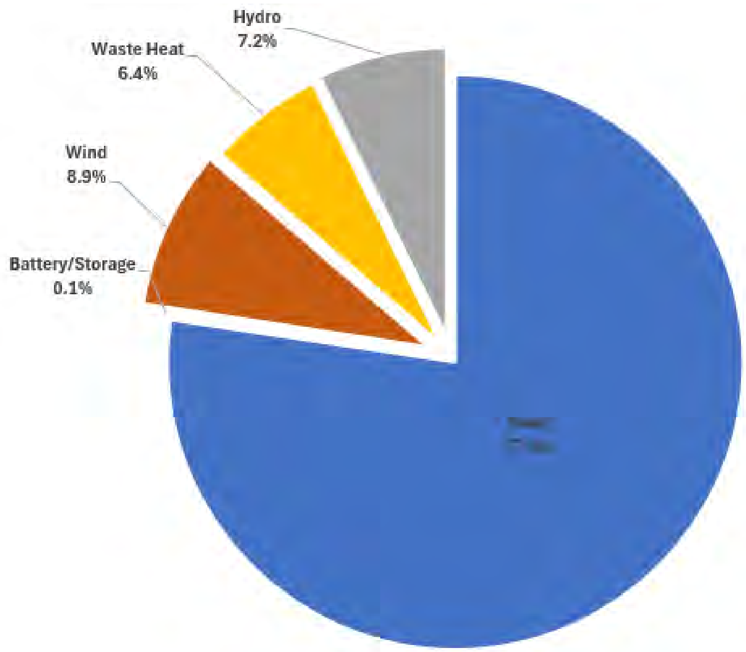


Figure 6 shows the breakdown of these projects by technology category. As of December 31, 2024, fifty-eight renewable or distribution generation projects totaling 90 MW were in operation across 20 Member Systems, with solar technology comprising over 77% of Member generation distributed resources.

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

Cummulative

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 TARGETS[21]

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.

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[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.