

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit A: Department, Order No. 202-25-14 (Dec. 30, 2025)



Department of Energy
Washington, DC 20585

Order No. 202-25-14

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

BACKGROUND

Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig is operated by the Tri-State Generation and Transmission Association (Tri-State). Craig consists of three coal-fired generation units, Unit 1 (446.4 MW), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined name plate capacity of 1427.6 MW.³ Unit 1 and Unit 2 are co-owned by Tri-State, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy (co-owners).⁴ Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979 respectively. Unit 3 began operations in 1984. Unit 1 is slated to cease operations in December 2025. Unit 2 and Unit 3 are slated to retire in 2028.⁵

EMERGENCY SITUATION

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

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

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

⁵ As a coal-fired facility, it would be difficult for the Craig Unit 1 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Tri-State and co-owners were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

during shoulder periods where solar availability is dropping but loads remain high.⁶

The 2024 WECC Western Assessment of Resource Adequacy notes that peak demand in WECC's Northwest-Central subregion, which includes Colorado, is "forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034."⁷ Meanwhile, WECC notes that most planned retirements are "baseload generation, such as coal, natural gas, and nuclear."⁸

Since 2019, 571.3 MW of coal-fired generating capacity across six units at three locations have retired in Colorado,⁹ leading to a decline in the share of coal-generated electricity from 45% to 28%.¹⁰ Looking forward, by 2029, about 3,700 megawatts of coal-fired generating capacity in Colorado is scheduled to retire according to the Energy Information Administration (EIA),¹¹ accounting for all but one coal-fired power plant in Colorado. In that same time frame, 675.6 MW of natural gas-fired generating capacity in Colorado will retire as well.¹² In 2025, intermittent wind accounted for over 5,300 MW of Colorado's electricity generating capacity.¹³

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 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."¹⁴ 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."¹⁵ 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

⁶ NERC 2024 Long-Term Reliability Assessment, at 130 (Dec. 2024, corrected Jul. 11, 2025), https://www.nerc.com/globalassets/ourwork/assessments/2024-ltra_corrected_july_2025.pdf.

⁷ Western Electricity Coordinating Council, *Western Assessment of Resource Adequacy 2024: Peak Demand by Subregion*, at 2, <https://www.wecc.org/sites/default/files/documents/products/2024/WARA%202024%20Peak%20Demand%20by%20Subregion.pdf>.

⁸ Western Electricity Coordinating Council, *Western Assessment of Resource Adequacy*, <https://feature.wecc.org/wara/>.

⁹ *Id.*

¹⁰ U.S. Energy Information Administration, *Electricity Data Browser, Net Generation for All Sectors Annually from 2019-2024, State: Colorado*, (last accessed Dec. 30, 2025), <https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvp&geo=0000000000g&sec=g&freq=A&start=2019&end=2024&ctype=linechart<ype=pin&rttype=s&pin=&rse=0&matype=0>.

¹¹ U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Conventional Steam Coal* (Nov. 2025), <https://www.eia.gov/electricity/data/eia860m/>.

¹² U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Natural Gas Fired Combustion Turbine and Natural Gas Stream Turbine* (Nov. 2025), <https://www.eia.gov/electricity/data/eia860m/>.

¹³ U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of November 2025, Plant State: Colorado, Technology: Onshore Wind Turbine* (Nov. 2025), <https://www.eia.gov/electricity/data/eia860m/>.

¹⁴ 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>.

¹⁵ *Id.*

of artificial intelligence data centers and increase in domestic manufacturing.”¹⁶

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.”¹⁷

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.”¹⁸ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Craig Unit 1 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.

I have made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Craig Unit 1 shall be made available for operation until March 30, 2026.

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

- A. From December 30, 2025, Tri-State and the co-owners, shall take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as Balancing Authority or the Southwest Power Pool (SPP) West in its role as the Reliability Coordinator, as applicable.¹⁹ Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry

¹⁶ 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>.

¹⁷ U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (Jul. 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

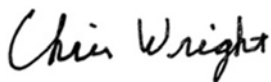
¹⁸ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

¹⁹ U.S. Energy Information Administration, Form EIA-860, Schedule 3: Plant Data (2024), <https://www.eia.gov/electricity/data/eia860/>.

practices.

- B. To minimize adverse environmental impacts, this Order limits operation of Craig Unit 1 to the times and within the parameters established in paragraph A. Tri-State shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Craig Unit 1 has operated in compliance with this Order.
- C. All operations of Craig Unit 1 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. 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 20, 2026, Tri-State, in coordination with the co-owners, 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 Craig Unit 1 consistent with this Order. Tri-State and the co-owners shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. Tri-state and the co-owners are directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for Craig Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Craig Unit 1 shall not be considered a capacity resource.
- H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 30, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 30, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 7:08PM EST on this 30th day of December 2025.



Chris Wright
Secretary of Energy

cc:

FERC Commissioners

Chairman Laura V. Swett

Commissioner David Rosner

Commissioner Lindsay S. See

Commissioner Judy W. Chang

Commissioner David A. LaCerte

Colorado Public Utilities Commission

Chairman Eric Blank

Commissioner Megan Gilman

Commissioner Tom Plant

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Federal Power Act Section 202(c))	Order No. 202-26-21
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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit AA: CoPUC, Decision No. R24-0602, issued on August 22, 2024,
in Proceeding No. 23A-0585E

Decision No. R24-0602

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 23A-0585E

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

**RECOMMENDED DECISION
GRANTING UNOPPOSED JOINT MOTION TO APPROVE
COMPREHENSIVE SETTLEMENT AGREEMENT,
APPROVING COMPREHENSIVE SETTLEMENT
AGREEMENT, AND GRANTING ELECTRIC RESOURCE
PLAN APPLICATION AS AMENDED BY
COMPREHENSIVE SETTLEMENT AGREEMENT**

Issued Date: August 22, 2024

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I. STATEMENT**A. Procedural Background¹**

1. On December 1, 2023, Tri-State Generation and Transmission Association, Inc. (“Tri-State”) filed its 2023 Electric Resource Plan (“ERP”) Application (“Application”), including the Direct Testimony of eight witnesses and attachments to the same. The filing of the ERP Application commenced this Proceeding.

2. By Decisions No. R24-0080-I and R24-0085-I², issued February 6 and February 8, 2024, respectively, the undersigned Administrative Law Judge (“ALJ”), among other things: acknowledged the interventions of the trial staff of the Colorado Public Utilities Commission (“Staff”), Office of Utility Consumer Advocate (“UCA”), the Colorado Energy Office (“CEO”), and Big Horn Rural Electric Company, Carbon Power & Light, Inc., High West Energy Inc., Wheatland Rural Electric Association, Wyrlec Company, Inc., Niobrara Electric Association, High Plains Power, Inc., Garland Light & Power Co., (collectively, the “Wyoming Cooperatives”), Poudre Valley Rural Electric Association, Inc. (“PVREA”), Highline Electric Association (“Highline”), K.C. Electric Association (“K.C.”), San Isabel Electric Association, Inc. (“SIEA”), Southeast Colorado Power Association (“SECPA”), and Y-W Electric Association, Inc. (“Y-W”); granted the interventions of the Natural Resources Defense Council and the Sierra Club (together, the “Conservation Coalition”), White River Electric Association (“WREA”), Western Resource

¹ The entire procedural history of this proceeding is provided in previous decisions and is partially repeated here, to the extent necessary to provide procedural context for the above-titled decision.

² Decision No. R24-0085-I provided certain clarifications for Decision No. R24-0080-I.

Advocates (“WRA”), Office of Just Transition (“OJT”), the Colorado Independent Energy Association (“CIEA”), Colorado Department of Public Health and Environment (“CDPHE”), Interwest Energy Alliance (“Interwest”), La Plata Electric Association, Inc. (“LPEA”) and Mountain Parks Electric, Inc. (“MPE”) (together, “LPEA/MPE”), the Colorado Solar and Storage Association (“COSSA”) and the Solar Energy Industries Association (“SEIA”) (together, “COSSA/SEIA”), and Moffat County (“Moffat”) and the City of Craig (“Craig”), Colorado (together, “Moffat/Craig”); and a procedural scheduled to govern this Proceeding.

3. By Decision No. R24-0138-I, issued March 5, 2024, the undersigned ALJ adopted a revised procedural schedule to govern this Proceeding. Among other deadlines, the decision set a June 26, 2024 deadline for Stipulations/Settlement Agreements; a July 1, 2024 deadline for Witness Lists, Cross-Examination Estimates, and Final Exhibits List; a July 11, 2024 deadline for Settlement Testimony; a July 16-19, 2024 Evidentiary Hearing; and an August 1, 2024 deadline for Statements of Position.

4. On April 22, 2024, Tri-State filed Supplemental Direct Testimony, providing additional information in support of the Application.

5. On May 15, 2024, the Colorado Air Pollution Control Division (“APCD”) filed its Verification Report (“Emissions Report”), verifying Tri-State’s calculation of a forecasted emissions reduction of 89 percent by 2030 from Colorado sales for the submitted preferred portfolio.

6. By Decision No. R24-04060-I, the ALJ again modified the procedural schedule, extending the filing deadline for any settlement agreements through June 28, 2024.

7. On June 27, 2024, Tri-State, Highline, PVREA, Y-W, Interwest, Staff, UCA, CEO, Moffat/Craig, OJT, CIEA, COSSA/SEIA, Conservation Coalition, and WRA (the “Settling

Parties”) filed their Unopposed Comprehensive Settlement Agreement (“Settlement Agreement”). With the Unopposed Comprehensive Settlement Agreement, the Settling Parties also filed their Joint Unopposed Motion to Approve the Unopposed Comprehensive Settlement Agreement, Amend the Procedural Schedule, and Waive Response Time (“Motion”). In the Motion, the Settling Parties indicate that the Wyoming Cooperatives, LPEA/MPE, WREA, K.C., SIEA, and SECPA do not oppose the Motion or the Settlement Agreement.³

8. By Decision No. R24-0496-I, issued July 10, 2024, the undersigned ALJ waived response time for the Motion, vacated the evidentiary hearing and the deadline for the filing of Statements of Position, and indicated that any additional relief sought in the Motion will be ruled upon by separate decision.

9. On July 7 and 9, 2024, the undersigned ALJ held Public Comment Hearings in this matter.

10. On July 10, 2024, Hearing Exhibit 203, the Settlement Testimony of Rebecca V. Lim (Staff’s Settlement Testimony) was filed by Staff.

11. On July 11, 2024, Hearing Exhibit 122, the Settlement Testimony and Attachments of Susan K. Hunter on Behalf of Tri-State Generation and Transmission Association, Inc. (“Hearing Exhibit 122” or “Ms. Hunter’s Settlement Testimony”) Hearing Exhibit 123, the Settlement Testimony and Attachments of Lisa K. Tiffin on Behalf of Tri-State Generation and Transmission Association, Inc. (“Hearing Exhibit 123” or “Ms. Tiffin’s Settlement Testimony”), Hearing Exhibit 124, the Settlement Testimony and Attachments of Brian L. Thompson on Behalf of Tri-State Generation and Transmission Association, Inc. (“Hearing Exhibit 124” or “Mr. Thompson’s Settlement Testimony”), and Hearing Exhibit 125, the Settlement Testimony and

³ Motion at 2.

Attachments of Chad Orvis on Behalf of Tri-State Generation and Transmission Association, Inc. (collectively, “Tri-State’s Settlement Testimony”) were filed by Tri-State.

12. On July 12, 2024, Hearing Exhibit 903 Testimony of Clare Valentine in Support of Settlement on Behalf of Western Resource Advocates (“Hearing Exhibit 903” or “WRA’s Settlement Testimony”) was filed by WRA.

13. On July 11, 2024, Hearing Exhibit No. 1603 Settlement Testimony of Commissioner Melody Villard on Behalf of the Coal Transition Communities, Moffat County and the City of Craig, Colorado (“Hearing Exhibit 1603” or “Moffat/Craig’s Settlement Testimony”) was filed by Moffat/Craig.

14. On July 11, 2024, Hearing Exhibit 1501 Settlement Testimony of Mike Kruger on Behalf of Colorado Solar and Storage Association and Solar Energy Industries Association (“Hearing Exhibit 1501” or “COSSA/SEIA’s Settlement Testimony”) was filed by COSSA/SEIA.

15. On July 12, 2024, the Answer Testimony of Wade Buchanan on Behalf of the Colorado Office of Just Transition Hearing Exhibit 1000⁴ was filed by OJT.

B. Background for This Proceeding

16. Tri-State is a generation and transmission cooperative that provides electric transmission service and is a wholesale seller of electric energy to 42 Utility Members in its service territory of four states using facilities located in five states.⁵ Tri-State owns, operates, or has a major equipment ownership interest in more than 5,665 miles of high-voltage transmission lines and approximately 409 substations and switchyards.⁶ Tri-State’s interstate transmission facilities

⁴ Although the title of this filing included the words “Answer Testimony,” its timing and content make it clear it was intended as to be filed as OJT’s Settlement Testimony and is therefore considered herein as such.

⁵ Hearing Exhibit 107 at 6:9-11 (Direct Testimony and Attachments of Ryan J. Hubbard on Behalf of Tri-State Generation and Transmission Association, Inc.).

⁶ *Id.* at 6:11-14.

are interconnected to other utilities, including Western Area Power Administration, Nebraska Public Power District, Black Hills Colorado Electric, Inc., PacifiCorp, Public Service Company of Colorado, Platte River Power Authority, Colorado Springs Utilities, Basin Electric Power Cooperative, Tucson Electric Power, Public Service Company of New Mexico, and Deseret Generation & Transmission Cooperative.⁷

17. This Proceeding concerns Tri-State's second ERP application submitted pursuant to Rule 3605.⁸ The Application, with its supporting testimony and attachments, are intended to describe how Tri-State will ensure reliability and resource adequacy, maintain affordability for its members, and meet compliance obligations, including environmental responsibility obligations.⁹

18. A significant component underlying the Application is that on September 13, 2023, Tri-State submitted a Letter of Interest to the United States Department of Agriculture ("USDA"), seeking significant funding through the Empowering Rural America ("New ERA") program of the Rural Utilities Service. The New ERA program, which was established through the Inflation Reduction Act ("IRA"), includes \$9.7 billion in federal funding for financial assistance to support the purchase of renewable energy, zero-emission, and carbon capture systems.¹⁰ In its Application, Tri-State put forward as its preferred portfolio an IRA Scenario that included several actions based on its application to the New ERA program. These actions included the acquisition of 255 MW owned renewable energy projects, 1,380 Megawatt ("MW") renewable and hybrid power purchase agreement projects, and 210 MW battery storage projects; and the retirements of Craig Unit 3 as of January 1, 2028, and Springerville Unit 3 no later than September 15, 2031.

⁷ *Id.* at 6:15-21.

⁸ Application at 1. *See also*, Proceeding No. 20A-0528E, which concerned Tri-State's first ERP Application with the Commission.

⁹ *Id.* at 2.

¹⁰ Attachment 1 to the Application (Stipulation between Tri-State, CEO, COSSA, UCA, County Electric Cooperative, Inc., Mountain View Electric Association, Inc., Sierra Club, and WRA), at 2-3.

19. With its Application, Tri-State submitted a stipulation with certain external stakeholders who agreed to support its acquisition in Phase II of resources pursuant to Tri-State's application to USDA, if its request for federal funding is approved in full.¹¹ Subsequently, in Supplemental Direct Testimony, Tri-State announced that it had received a notice to proceed from the USDA, and would thus be submitting a full application for New ERA funding.¹² At the time of this Decision, no announcements have been made by USDA regarding New ERA program awards.

C. Settlement Agreement¹³

1. General Terms, Contents of the Phase II Implementation Report, and Injection Study

20. The Settlement Agreement, which is attached to this Recommended Decision as Appendix A, sets forth the Settling Parties' agreement resolving all disputed issues in this Proceeding.¹⁴

21. The Settling Parties have agreed that the Commission should grant Tri-State's Application for approval of its 2023 ERP, subject to the terms of the Settlement Agreement. The Settling Parties agree that the compromise reached between the Settling Parties constitutes a just and reasonable resolution of all issues as part of Phase I of the ERP.¹⁵

22. In addition to certain specific terms which are discussed below, the Settling Parties also have agreed to numerous General Terms and Conditions, found in Section 6 of the Settlement Agreement.¹⁶

¹¹ *Id.* at 8.

¹² Hr. Ex. 101, Tiffin Supplemental Direct, p. 6.

¹³ The following is intended as a summary of some of the main terms of the Settlement Agreement, rather than a full recitation of the same.

¹⁴ Settlement Agreement, ¶1.3.

¹⁵ *Id.*

¹⁶ *See id.*, at 31-34.

23. The Settling Parties have agreed upon certain contents of the Phase II Implementation Report, which is to be submitted 165 days after Phase II RFPs have been released.¹⁷ The Implementation Report will include the items listed in Hearing Exhibit 101, Attachment LKT-3; annual emissions in short tons; a map of all Phase II bids, with an overlay identifying Disproportionately Impacted (“DI”) Communities; highly confidential technical specifications for any gas resource bids advanced to Phase II modeling; identification of any bids located in Moffat County or the West End of Montrose County; and, for any bids located in the same areas, an estimate of the annual property tax expected to be paid to the county for bids selected and an explanation of why a given bid is not advanced to Phase II modeling, if applicable.¹⁸

24. Following Phase II, Tri-State agrees to conduct an injection study reflecting the anticipated Colorado transmission system in 2031, as further set forth in ¶4.11 of the Settlement Agreement.¹⁹

2. Requests for Proposals

25. The Settling Parties have agreed that the Commission should approve a Dispatchable Request for Proposals (“RFP”), a Standalone Storage RFP, and a Renewable RFP for issuance in Phase II.²⁰ While resources that are included within Tri-State’s New ERA application will retain certain requirements related to geographic location, size, and technology type, Tri-State will remove those restrictions for RFPs seeking resources that are not included within the New ERA application.²¹

¹⁷ Hr. Ex. 101, Attachment LKT-2, Rev. 1.

¹⁸ Settlement Agreement, ¶4.10.

¹⁹ *Id.*, ¶4.11.

²⁰ *Id.*, ¶4.2.

²¹ *Id.* at ¶¶4.2.1., 4.2.3., 4.2.4., 4.2.5.

26. Furthermore, within one week of receiving a notice of award from USDA regarding New ERA funding, Tri-State commits to request a meeting with USDA to discuss flexibility related to funded projects. Tri-State will then file an informational notice with the Commission.²² If New ERA guidance is provided at least 10 days before the issuance of the RFPs, Tri-State will modify its RFPs to match that guidance and informationally refile them with the Commission.²³

27. The Settling Parties have agreed that Tri-State will modify Phase II Bid Security and refundability requirements, as further set forth in ¶4.2 of the Settlement Agreement. Among such modifications is the requirement for selected bidders to submit \$10,000 per nameplate capacity megawatt (“MW”) on a given project, due within 21 days of Tri-State filing its Phase II ERP Implementation Report.²⁴

28. The Dispatchable RFP process will be modified so that the geographic location for gas plant bids (except tolling agreements) will be limited to Moffat County, no limits will be imposed on technology type or MW size, and Dispatchable RFPs must meet the carbon dioxide emission rate and performance requirements identified in the greenhouse gas emissions rules promulgated by the Environmental Protection Agency, as further set forth in ¶ 4.2.6 of the Settlement Agreement.

29. For each Phase II portfolio modeled by Tri-State pursuant to ¶4.3 of the Settlement Agreement, Tri-State is required to model an Extreme Weather Event (“EWE”) sensitivity (“EWE Sensitivity”), including the requirement on Tri-State to model the EWE Sensitivity in the dispatch only, without informing the expansion plan of the EWE modeling parameters, and otherwise comply with the remaining terms set forth in ¶4.4 of the Settlement Agreement.

²² *Id.* at ¶ 4.2.7.

²³ *Id.* at ¶¶4.2.8., 4.2.8., 4.2.10.

²⁴ *Id.*, ¶4.2.2.1.

30. Bids with commercial operational dates in 2026 and 2027 also will be required to have an established generator interconnection queue position.²⁵ Bids beyond those dates without an interconnection queue position will be entered into the Tri-State interconnection queue.²⁶

31. The Settling Parties agree that Tri-State will update certain non-price factor bid evaluation criteria for its RFPs. Tri-State will make the relevant non-price factor information available to bidders as well as assumptions for use of surplus interconnection service at Tri-State-owned facilities. Among other changes, Tri-State will amend the “Development and Siting Status” narrative topics requested from bidders to address Community Stewardship, Tribal Consultation, and Land Use considerations—and specifically to seek information on community engagement and wildlife surveys—as further set forth in ¶4.7 of the Settlement Agreement.

3. Phase II Portfolios and Modeling and 2027 ERP

32. The Settling Parties have further agreed upon eight portfolios to be modeled in Phase II, with the potential for two additional portfolios to be modeled. These include Tri-State’s preferred plan; a version of the preferred plan that allows other gas plant technology types (in addition to natural gas carbon capture and storage); a version of the preferred plan in which the model will not be required to select a gas resource, and constraints would be removed for non-New-ERA resources; a version of the preferred plan that limits gas resources to tolling agreements; an unconstrained portfolio that allows the model to choose resources; a “no new gas” portfolio, contingent on whether all other portfolios select new gas resources; an optional portfolio of Tri-State’s choosing; and back-up bid portfolios, as further set forth in ¶4.3 of the Settlement Agreement.

²⁵ *Id.*, ¶4.5.

²⁶ *Id.*

33. Tri-State agreed to update modeling assumptions for non-tolling agreement gas plant bids to have a useful life of no later than 2050.²⁷

34. For each Phase II portfolio modeled by Tri-State pursuant to ¶4.3 of the Settlement Agreement, Tri-State is required to model an EWE Sensitivity and comply with the remaining terms set forth in ¶4.4 of the Settlement Agreement. Tri-State will also remodel any portfolios that fail to meet the Level II reliability criteria related to EWE Sensitivity.²⁸

35. Tri-State also agreed to aim to control at least 5.5% of Tri-State's Colorado peak load through demand response programs by 2030.²⁹ Tri-State also agreed to model in-house demand response offerings to that effect.³⁰

36. Tri-State will further subject each portfolio to at least 24 hours of run time in its modeling software, EnCompass.³¹

37. Tri-State will use the Phase II bids that pass bid evaluation as inputs to inform its 2027 ERP generic resource assumptions used in Phase I modeling of that ERP, as further set forth in ¶4.12 of the Settlement Agreement. Applicable federal environmental compliance obligations will be reflected in this modeling.³²

4. Facility Retirements

38. The Settling Parties agree that the Commission should approve retirement date of January 1, 2028 for Unit 3 of Tri-state's Craig Station ("Craig 3"). The Settling Parties agree that the Commission should approve a retirement date of September 15, 2031 for Unit 3 of the Springerville Generating Station ("Springerville 3"), subject to New ERA funding award as

²⁷ *Id.*, ¶4.4.6.

²⁸ *Id.*, ¶4.8.1.

²⁹ *Id.*, ¶4.9.1.

³⁰ *Id.*, ¶4.9.2.

³¹ *Id.*, ¶4.4.7.

³² *Id.*, ¶4.12.

requested from USDA and successful Tri-State negotiation of contractual agreements impacted by the unit's retirement.³³ Depending on whether New ERA funding is awarded to Tri-State, the Settling Parties agree to convene a meeting to discuss the modeling of Springerville 3, or for Tri-State to update common facilities costs for Springerville 3 and model the cost of any applicable federal environmental compliance obligations for Springerville 3 for Phase II modeling, as set forth in ¶4.6.1 of the Settlement Agreement.

5. Community Assistance

39. The Settlement Agreement also includes Section 5, which represents specific agreements between Tri-State and Craig/Moffat regarding community assistance.³⁴ While not joined by other Settling Parties, other parties convey their support or non-opposition for these provisions.

40. Tri-State agrees to provide a direct benefit payment for community assistance to Moffat/Craig in the amount of \$5.5 million per year, to be paid between 2026 through 2029. The payment will go to an economic development fund established and administered by Moffat/Craig.³⁵

41. Tri-State and Moffat/Craig agree that Phase I modeling identified the need for a gas plant in western Colorado with the potential to be sited in Moffat, consistent with Tri-State's siting study. Accordingly, in Phase II of its ERP, Tri-State will solicit bids for a gas plant to be sited in Moffat.³⁶ Tri-State and Moffat/Craig agree that no additional Commission approvals should be required for the gas plant if selected and approved in Phase II, however, Moffat/Craig agree to

³³ *Id.*, ¶4.6.

³⁴ *Id.*, ¶5.1.

³⁵ *Id.*, ¶5.2.

³⁶ *Id.*, ¶5.3.

support any further filings if required by the Commission, and Tri-State commits to provide drafting and/or administrative support for Moffat/Craig.³⁷

42. Tri-State agrees to make certain “minimum backstop payments,” to an economic development fund designated by Moffat/Craig. The backstop payments will total \$48 million and will be paid out in decreasing increments, beginning in 2028 and ending in 2038. The minimum backstop payments are subject to offset for various items, including property tax revenues paid by Tri-State, federal or state grant funds, and other items agreed-upon items, as further set forth in ¶¶5.3.5, 5.3.6 and 5.3.7 of the Settlement Agreement.

43. In the evaluation and modeling of bids located in Moffat, Tri-State agrees to implement a \$1/MWh price improvement over the life of a proposed project or contract.³⁸ The 2023 ERP Phase II “preferred portfolio” will be modeled with and without this price improvement.³⁹

44. Within six months of the retirement of all three units at Craig Station, Tri-State will transfer to Moffat (upon consent of the Colorado River Water Conservation District), at no cost, storage water rights from Elkhead Reservoir, Second Enlargement (originally decreed in 02CW106), in an amount sufficient for the augmentation plan that is approved in Case No. 23CW3025 as determined by the Colorado Division of Water Resources and/or the Division 6 Water Court, and as further set forth in ¶5.5 of the Settlement Agreement.

45. Tri-State agrees to directly communicate with Moffat/Craig and OJT regarding significant workforce decisions related to Craig 3, as further set forth in ¶5.6 of the Settlement Agreement.

³⁷ *Id.*, ¶5.3.3.

³⁸ *Id.*, ¶5.4.1.

³⁹ *Id.*

46. Moffat/Craig and Tri-State agree to meet twice annually from 2025 to 2028 leading up to the Craig Station closure to identify opportunities where Tri-State's assets can be utilized to facilitate development in Moffat while also benefiting Tri-State's member systems, as further set forth in ¶5.7 of the Settlement Agreement.

47. Moffat/Craig agree not to seek further community assistance or workforce transition benefits from Tri-State in the future, or take positions on workforce transition reporting before a regulatory body, court, legislative body, or through discussions or communications with others that are inconsistent with the terms of the Settlement Agreement, as further set forth in ¶55 of the Settlement Agreement.

II. ANALYSIS

A. Burden of Proof

48. Except as otherwise provided by statute, the Administrative Procedure Act imposes the burden of proof in administrative adjudicatory proceedings upon "the proponent of an order."⁴⁰ The Settling Parties filed the Joint Motion and, as a result, bear the burden of proof.⁴¹ The Settling Parties must establish by a preponderance of the evidence that the Settlement Agreement is just and reasonable and in the public interest. The Commission has an independent duty to determine matters that are within the public interest.⁴²

B. Modified Procedure

49. The Application, as modified by the Settlement Agreement, is uncontested. The Settlement Agreement was executed by each of the Settling Parties and is otherwise unopposed as

⁴⁰ Section 24-4-105(7), C.R.S.

⁴¹ Section 24-4-105(7), C.R.S.; § 13-25-127(1), C.R.S.; Rule 1500 of the Rules of Practice and Procedure, 4 CCR 723-1.

⁴² See *Caldwell v. Public Utilities Commission*, 692 P.2d 1085, 1089 (Colo. 1984).

is the Motion.⁴³ In addition, the parties agree that a hearing is unnecessary.⁴⁴ Finally, the Application and Settlement Agreement are supported by sworn testimony and attachments that verify sufficient facts to support the Application and Settlement Agreement. Accordingly, pursuant to § 40-6-109(5), C.R.S. and Rule 1403 of the Rules of Practice and Procedure, 4 *Code of Colorado Regulations* (“CCR”) 723-1,⁴⁵ the Application, as modified by the Settlement Agreement, will be considered under the modified procedure, without a formal hearing.

C. Analysis

50. Based upon substantial evidence in the record as a whole, the ALJ finds and concludes that the Settlement Agreement is just and reasonable and not contrary to the public interest. The ALJ shall approve the Settlement Agreement without material modifications and shall grant the Application, as modified and clarified by the Settlement Agreement and the testimony referenced therein.⁴⁶ In so doing, the ALJ approves Tri-State’s assessment of need during the resource acquisition period, its plans for acquiring additional resources, and its proposed model contracts and evaluation criteria.

51. Paragraphs 4.2. and 5.3 of the Settlement Agreement (and the subparagraphs contained therein) thoroughly set forth the process and requirements for Phase II RFPs as well as the location (Moffat) of a gas plant for which Tri-State would solicit RFPs during Phase II. Multiple public comments addressed the public’s concern as to the construction of a gas plant in Moffat.⁴⁷ Nonetheless, the ALJ is satisfied by the flexibility in the modeling requirements set forth

⁴³ Motion at 4-5.

⁴⁴ *Id.*

⁴⁵ 4 CCR 723-1.

⁴⁶ See Settlement Agreement, ¶4.3.7.

⁴⁷ See, e.g., Public Comment Hr. Tr. for July 11, 2024 Public Comment Hr. at 13:1-8, 15:21-16:2, 20:1-13, and 35:12-21.

by the Settlement Agreement, which includes a requirement to model at least one portfolio with no new gas resources, should all other portfolios incorporate new gas resources.

52. Paragraph 4.2.2 of the Settlement Agreement set forth requirements regarding bid fees and bid security for Phase II RFPs. The ALJ finds that these provisions appropriately address concerns previously raised by COSSA/SEIA and Staff and are otherwise reasonable and not contradictory to the public interest.⁴⁸

53. Paragraphs 4.2.7 – 4.2.10 of the Settlement Agreement addresses the New ERA Application. The New ERA Application was a primary area of concern for Staff prior to the execution of the Settlement Agreement.⁴⁹ The ALJs agree with the Settling Parties that the changes to Tri-State's Phase II RFPs provide reasonable flexibility while still ensuring that Tri-State can leverage federal funding. Moreover, Tri-State commits specifically to address grant flexibility with USDA and to provide informational updates to the Commission. The ALJ finds that the terms relating to the New ERA Application are reasonable and not contradictory to the public interest.

54. Paragraph 4.3 of the Settlement Agreement addresses the portfolios to be modeled by Tri-State in Phase II. The ALJ agrees with the Settling Parties that the portfolios to be modeled by Tri-State in Phase II promote flexibility and ensure the availability of sufficient options and combinations which would allow evaluation of backup options and help to inform the decision as to the need for additional gas resource.⁵⁰

55. Paragraphs 4.4.1, 4.8.1, 4.8.2, and 4.8.3 of the Settlement Agreement address EWE Sensitivity. Notably, Tri-State will model the EWE Sensitivity in the dispatch only, without informing the expansion plan of the EWE modeling parameters. This approach is different than

⁴⁸ See Hr. Ex. 1501, p. 2:15-19; Hr. Ex. 203, p. 9:5-12; See also Hr. Ex. 122, pp. 5:22-6:16.

⁴⁹ See Hr. Ex. 200, pp. 38:15-39:11.

⁵⁰ See Hr. Ex. 903, p. 8:5-12; Ex. 402, pp. 8:19-9:2; Hr. Ex. 203, pp. 13:7-14:16; and Hr. Ex. p. 4:12-15.

the Phase I approach to EWE modeling. The ALJ finds that the EWE Sensitivity provisions are reasonable and not contradictory to the public interest.

56. As mentioned above, ¶4.1 of the Settlement Agreement states that the Settling Parties agree that Tri-State’s 2023 ERP should be approved pursuant to Commission Rule 3605(g)(III), subject to the terms of the Settlement Agreement, without modification. The Wyoming Cooperatives, LPEA/MPE, WREA, K.C., SIEA, and SECPA do not oppose the Motion or the Settlement Agreement.⁵¹ In its Answer Testimony,⁵² LPEA/MPE stated that the Commission should “[d]irect Tri-State to model at least one ‘lower load’ scenario under which one or more additional members exit the Tri-State system, and consider the results of that scenario in the Phase I decision...”⁵³ As the lack of any objection by LPEA/MPE to the Motion or the Settlement Agreement and Tri-State’s Rebuttal Testimony⁵⁴ suggests, this issue was satisfactorily resolved by Tri-State’s commitment to update its load forecast during Phase II modeling to incorporate LPEA’s departure beginning in April 2026 and the removal of Partial Requirements starting January 2026.⁵⁵ However, this commitment by Tri-State is not specifically set forth in the Settlement Agreement. Therefore, the Supplemental Direct Testimony of Lisa K. Tiffin, Hr. Ex. 110, which specifically addresses this commitment by Tri- State, will be incorporated by reference to the Settlement Agreement, as ordered below.

57. Paragraphs 4.4.4, 4.4.5, and 4.4.6 discuss modeling assumptions and obligations by Tri-State regarding CO2 emission rate, carbon capture and sequestration, federal production tax credits, and the useful life of gas plants. The ALJ agrees that these modeling assumptions and

⁵¹ Motion at 2; Settlement Agreement, ¶1.2.

⁵² Hr. Ex. 1400.

⁵³ *Id.*, p. 6:6-8.

⁵⁴ Hr. Ex. 113.

⁵⁵ *Id.* 8, 9-11.

obligations “align with the recommendations that WRA put forward in answer and cross-answer testimony, while reflecting a degree of compromise in the interest of settlement[;]”⁵⁶ are intended to be consistent with the New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, published in the Federal Register on May 9, 2024[.]⁵⁷ Therefore, the ALJ finds that the provisions in the Settlement Agreement that address modeling assumptions and obligations by Tri-State regarding CO2 emission rate, carbon capture and sequestration, federal production tax credits, and the useful life of gas plants, are reasonable and not contradictory to the public interest.

58. Paragraphs 4.4.7 and 4.4.8 of the Settlement Agreement sets forth guidelines for Tri-State’s use of the EnCompass software to run its modeling. Staff notes, and the ALJ agrees, that the guidelines for Tri-State’s use of the EnCompass software to run its modeling, as set forth in the Settlement Agreement, addresses Staff’s prior concerns about Tri-State’s EnCompass software configuration.⁵⁸ The ALJ finds that the provisions in the Settlement Agreement that address Tri-State’s use of the EnCompass software to run its modeling are reasonable and not contradictory to the public interest.

59. Paragraph 4.5 of the Settlement Agreement sets forth Phase II bid generator interconnection criteria, including the requirement for bids for the years 2026-2027 to include generator interconnection queue position. The ALJ finds that that these criteria are reasonable and not contradictory to the public interest.

⁵⁶ Hr. Ex. 903, p. 7:18-20.

⁵⁷ Hr. Ex. 402, pp. 11:18-12:2 and Hr. Ex. 124, pp. 5:22-64.

⁵⁸ Hr. Ex. 203, pp.12:14-13:3.

60. Paragraph 4.6 of the Settlement Agreement states that the Settling Parties agree that the Commission should approve a retirement date of January 1, 2028 for Craig 3. The Settling Parties note, and the ALJ agrees, that the setting of a definite Craig 3 retirement date provides certainty for Moffat/Craig,⁵⁹ and while not easy to bear, is agreeable by Moffat/Craig.⁶⁰ The ALJ finds that a retirement date of January 1, 2028 for Craig 3 is reasonable and not contradictory to the public interest.

61. Paragraph 4.6 of the Settlement Agreement also states that the Settling Parties agree that the Commission should approve the retirement date of September 15, 2031 for Springerville 3, subject to certain conditions. Staff's concerns regarding modeling assumptions related to the cost of the retirement of Springerville 3 were appropriately addressed by the Settlement Agreement.⁶¹ Further, Tri-State notes that the retirement date of Springerville 3 aligns with the New ERA application, which would facilitate the reduction of the cost of retiring Springerville 3 for Tri-State Members and enable exiting of contractual agreements to not result in undue financial impact on Tri-State Members.⁶² The ALJ finds that a retirement date of September 15, 2031 for Springerville 3 is reasonable and not contradictory to the public interest.

62. Paragraph 5.6 of the Settlement Agreement discusses the requirements imposed on Tri-State to directly communicate with Moffat/Craig and OJT regarding significant workforce decisions related to Craig 3. Moffat/Craig believe, and the ALJ agrees, that these requirements would enhance communication between Tri-State and Moffat/Craig and assist Moffat/Craig with local economic development planning efforts.⁶³ The ALJ notes that a single commenter in this

⁵⁹ Hr. Ex. 402, p. 11:10-14.

⁶⁰ Hr. Ex. 1603, p. 5:3-12.

⁶¹ Hr. Ex. 203, p. 15:1-13.

⁶² Hr. Ex. 123, p. 8:15-23.

⁶³ Hr. Ex. 1603, pp. 16:13-17:9.

Proceeding stated that the labor force of Craig 3 was excluded from the negotiation table as it relates to the Settlement Agreement. The commenter noted that while the Craig 3 labor force has a letter of agreement in place with Tri-State, the letter does not fully address workforce transition or timing; and the labor force has not had sufficient time to consider and respond to the terms of the Settlement Agreement.⁶⁴ The ALJ considered this public comment and finds that the Settlement Agreement appropriately addresses workforce transition issues in light of Tri-State's legal obligations and its continued willingness to engage in discussions regarding the local economy. Section 5 of the Settlement Agreement incorporates certain community assistance opportunities that were identified in the Informational Community Assistance Plan ("ICAP") developed by Moffat/Craig, Tri-State, OJT, CEO, and UCA.⁶⁵ However the ICAP includes other opportunities that are not limited to the actions of this Commission. Therefore, the ALJ finds that the commitments made by Tri-State to directly communicate with Moffat/Craig and OJT regarding significant workforce decisions related to Craig 3 are reasonable and not contradictory to the public interest.

63. Paragraphs 5.2, 5.3.1, 5.3.2, 5.3.3, 5.3.4, 5.3.5, 5.3.6, 5.3.7, 5.7, and 5.9, of the Settlement Agreement set forth the parameters for the monetary community assistance to be provided by Tri-State to Moffat/Craig. A significant number of public comments emphasized the support of individual customers and local officials for community assistance.⁶⁶ COSSA/SEIA note that they strongly support the "Direct Benefit" to Moffat/Craig that the community assistance provisions of the Settlement Agreement provide.⁶⁷ COSSA/SEIA further state that while they do

⁶⁴ Public Comment Hr. Tr. for July 9, 2024 Public Comment Hr. at 48:4-19, 49:1-7, and 49:19-50:4.

⁶⁵ Hrg. Ex. 1601, Att. CN-1, at p. 4-7.

⁶⁶ See, e.g., Public Comment Hr. Tr. for July 9, 2024 Public Comment Hr. at 15:25-165, 19:14-19, 22:19-23:4, 25:19-26:13, 26:23-27:3, 28:10-21, 29:12-14, 30:9-14, 31:4-6, 32:19-33:11, and 53:10-54:2.

⁶⁷ Hr. Ex. 1501, p. 4:14-16.

not support the construction of a gas plant in Moffat/Craig, the Settlement Agreement provides for a competitive solicitation process that a natural gas plant will ultimately be constructed in Moffat/Craig.⁶⁸ Similarly, WRA states it supports the community assistance provisions of the Settlement Agreement, the community assistance provisions of the Settlement Agreement do not prematurely lock in the acquisition of new natural gas resources in Phase I of this Proceeding, and the construction of a gas facility in Moffat would provide an economic benefit to Moffat.⁶⁹ CEO, too, supports the community assistance provisions of the Settlement Agreement, as those are consistent with CEO's recommendations regarding Tri-State's Phase II gas resources modeling.⁷⁰

64. Moffat/Craig state that community assistance provisions of the Settlement Agreement align with the ICAP process that originated from the Tri-State 2020 ERP Settlement Agreement and brings many of the ICAP Report's community assistance opportunities to fruition.⁷¹ Moffat/Craig further state that Moffat/Craig have the most to lose in terms of annual tax base as a result of Colorado's transition away from coal, and the direct benefit payments and minimum backstop payments by Tri-State would help ease these impacts.⁷² Moffat/Craig also state that the goal of Tri-State's community assistance fund is to attract new industries and support existing local businesses in the area to help with replacement tax base sources and job creation resulting from the loss of Craig 3 and two coal mines.⁷³ Lastly, Moffat/Craig state that tax base sources and job creation could be assisted by the establishment of a natural gas facility in Moffat, which also aligns with the need for a dispatchable energy resource in Western Colorado to ensure

⁶⁸ *Id.*, p. 7:6-9.

⁶⁹ Hr. Ex. 903, p. 12:4-12.

⁷⁰ Hr. Ex. 402, p. 12:4-10.

⁷¹ Hr. Ex. 1603, p. 8:10-13.

⁷² *Id.*, p. 10:1-9.

⁷³ *Id.*, pp. 11:10-15, 13:13-14.

grid reliability.⁷⁴ Similarly, Staff “applauds” all parties involved in negotiating the community assistance provisions of the Settlement Agreement.⁷⁵ Tri-State states that the minimum backstop payments provisions of the Settlement Agreement, which allow for Tri-State’s payments to be reduced based on Tri-State’s investments in Moffat/Craig, can deliver value for Tri-State members and are otherwise aligned with Tri-State’s functions as a non-for-profit organization.⁷⁶ The ALJ agrees with the justifications set forth above and finds that the community assistance to be provided by Tri-State to Moffat/Craig is reasonable and not contradictory to the public interest.

65. Paragraph 5.5 of the Settlement Agreement sets forth the parameters for the free transfer of Tri-State’s water rights in Elkhead Reservoir to Moffat. Moffat/Craig state that securing Tri-State’s water rights was the third-ranked CAO in the Final ICAP Report because the Yampa River upstream of the confluence with the Little Snake River, including all of its tributaries, was designated as “Over-Appropriated” and Moffat relies on water replacement augmentation through a lease agreement with the Colorado River Water Conservancy District.⁷⁷ Moffat/Craig further state that being able to secure the transfer of water rights from Tri-State would ultimately allow Moffat to expand housing opportunities for workers of any industry and attract new residents to Moffat.⁷⁸ The ALJ agrees that the free transfer of water rights from Tri- State to Moffat provides a substantial benefit to Moffat/Craig, is reasonable under the circumstances, and not contradictory to the public interest.

⁷⁴ *Id.*, pp. 13:13-14:13.

⁷⁵ Hr. Ex. 203, p. 16:10-14.

⁷⁶ Hr. Ex. 123, p. 23:5-9.

⁷⁷ Hr. Ex. 1603, p. 15:8-18, *citing* Colorado Division of Water Resources, Over Appropriation of the Yampa River above the Confluence with the Little Snake River Letter (January 19, 2022), https://dnrweblink.state.co.us/dwr/0/edoc/3863278/DWR_3863278.pdf?searchid=20139195-951f-4bbd-a0fb-35562c8ddfee.

⁷⁸ *Id.*, p. 16:2-9.

66. Paragraphs 5.3, 5.4.1, 5.4.2, and 5.4.3 of the Settlement Agreement set forth parameters relating to gas plant bid solicitation, energy cost, letters of support to be produced by Moffat in connection with Tri-State’s 2023 ERP Phase II, 2027 ERP Phase I and II processes, and Moffat/Craig’s advocacy in connection with any bids in Moffat County selected as part of Tri-State’s preferred portfolio in Phase II of Tri-State’s 2027 ERP. According to Moffat/Craig, Tri-State’s application of a \$1/MWh price improvement over the life of the proposed project and siting replacement for gas plant bids could assist local communities without having to take more extreme measures that threaten Colorado’s marketplace.⁷⁹ According to CEO, the “price adder” set forth in the Settlement Agreement will help with bids located in Moffat not to be eliminated from the bid evaluation screening process before the non-price factor screen can be completed.⁸⁰ According to Moffat/Craig, gas plant bids siting replacement is in alignment with the third-party Generation Siting Study report authored by 1898 & Co., which selected a 239-acre Moffat County site in close proximity to Craig Station as the top location for a gas plant.⁸¹ The ALJ agrees that the siting and price preferences given by Tri-State to Moffat in the context of the Settlement Agreement are a reasonable methodology that balances providing a locational preference with offering competitive flexibility, and thus are reasonable and not contradictory to the public interest.

67. Paragraphs 4.7.1, 4.7.3.1, and 4.7.3.2 of the Settlement Agreement set forth parameters relating to non-price bid factors for Tri-State’s Phase II of the 2023 ERP. According to WRA, Tri-State’s agreement to make information available to bidders regarding each of the listed non-price factors in the bid policy, including, where possible, the factors’ relative weight,

⁷⁹ Hr. Ex. 1501, pp. 4:19-5:15.

⁸⁰ Hr. Ex. 402, p. 15:2-11, *citing* Hr. Ex. 400, Answer Testimony of Kathleen Gegner, p. 39:10-13.

⁸¹ Hr. Ex. 1603, pp. 7:15-8:2, *citing* 1898 & Co. Generation Siting Study Report (Hr. Ex. 112, Tri-State Supplemental Direct Testimony of Chris E. Pink, Rev. 1, Attachment CEP-2 (Public Version of Generation Siting Study Report), at 37 (filed April 22, 2024)).

will improve transparency about the proposed framework at the outset of Phase I and satisfy WRA's concerns in this regard.⁸² CEO states that it supports the non-price bid evaluation criteria set forth in the Settlement Agreement and explains that, as it understands it, tribal consultations, wildlife surveys, and/or plans to conduct such assessments, consultations, or surveys, will be offered on an informational basis and be otherwise consistent with Tri-State's existing and proposed processes, and that it is not creating additional requirements on bidders. The ALJ agrees that the non-price bid process outlined in the Settlement Agreement does not impose unreasonable requirements on developers, the process is otherwise reasonable under the circumstances, and is not contradictory to the public interest. The ALJ further notes that ¶4.7.1 of the Settlement Agreement, is consistent with §40-2-129(1)(b) and Rule 3605(h)(I)(A)(iii) of the Rules Regulating Electric Utilities, 4 CCR 723-3, which require Tri-State to provide the Commission with the best value employment metrics information provided by bidders as a part of its Phase II ERP Implementation Report.

68. Paragraph 4.9 of the Settlement Agreement sets forth three demand response requirements Tri-State must follow. According to WRA, the requirements on Tri-State to aim to control at least 5.5 percent of its Colorado peak load through demand response programs by 2030, although a compromise from WRA's initial proposal, represents a meaningful increase in Tri-State's future demand response capacity objectives.⁸³ According to Tri-state, the requirements set forth in ¶4.9 of the Settlement Agreement are "reasonable stretch goals." The ALJ agrees that the requirements set forth in 4.9 of the Settlement Agreement are reasonable and not contradictory to the public interest.

⁸² Hr. Ex. 903, p. 9:11-17.

⁸³ Hr. Ex. 903, p. 8:15-22.

69. Paragraph 4.10 of the Settlement Agreement sets forth the minimum requirements for Tri-State's Phase II Implementation Report. CEO previously suggested, and supports, the requirements on Tri-State to provide the annual carbon dioxide and methane emissions in short or metric tons in its ERP Implementation Report, for each proposed Phase II portfolio and map all Phase II bids against an overlay of the EnviroScreen data layer that identifies DI communities.⁸⁴ The ALJ finds that the requirements set forth in ¶4.10 of the Settlement Agreement are reasonable and not contradictory to the public interest.

70. Paragraph 4.11 of the Settlement Agreement sets forth criteria for Tri-State's Post-Phase II Transmission Injection Study. The ALJ finds that the requirements set forth in ¶4.11 of the Settlement Agreement are reasonable and not contradictory to the public interest.

71. Paragraphs 4.7.2, 4.9.3, 4.12 of the Settlement Agreement set forth certain requirements relating to Tri-State's 2027 ERP. According to WRA, the requirement on Tri-State to provide information in future annual progress reports on Regional Transmission Organization ("RTO") impacts to resource adequacy determination is "an appropriate starting place for understanding the impacts of RTO participation on electric resource planning," and complements other approaches for evaluating RTO participation and impacts on utility operations.⁸⁵ Tri-State explains that after the start of its participation in the Southwest Power Pool ("SPP"), which is scheduled for April 1, 2026, Tri-State will begin including certain SPP information in its ERP Annual Progress Reports, as specified in ¶4.12.3 of the Settlement Agreement.⁸⁶ The ALJ finds that the provisions of the Settlement Agreement relating to Tri-State's 2027 ERP are reasonable and not contradictory to the public interest.

⁸⁴ Hr. Ex. 402, p. 9:17-10:4.

⁸⁵ Hr. Ex. 903, pp. 10:16-11:2.

⁸⁶ Hr. Ex. 123, pp. 18:19-19:6.

72. Accordingly, in accordance with § 40-6-109, C.R.S., it is recommended that the Commission enter the following Order.

III. ORDER

A. It is Ordered That:

1. For the reasons stated above, the Joint Unopposed Motion to Approve the Unopposed Comprehensive Settlement Agreement, Amend the Procedural Schedule, and Waive Response Time, filed on June 27, 2024 by Tri-State Generation and Transmission Association, Inc., Highline Electric Association Highline, Poudre Valley Rural Electric Association, Inc., Y- W, Interwest Energy Alliance, Trial Staff of the Colorado Public Utilities Commission, the Office of the Utility Consumer Advocate, the Colorado Energy Office, Moffat County and the City of Craig, Office of Just Transition, the Colorado Independent Energy Association, Colorado Solar and Storage Association and the Solar Energy Industries Association, Conservation Coalition, and Western Resource Advocates (the “Settling Parties”) is granted.

2. The Unopposed Comprehensive Settlement Agreement (“Settlement Agreement”), filed by the Settling Parties on June 27, 2024 is approved, consistent with the discussion above. The Settlement Agreement is attached to this Decision as Appendix A.

3. The Supplemental Direct Testimony of Lisa K. Tiffin, Hearing Exhibit 110 is incorporated by this reference into the Settlement Agreement and is included as Appendix B to this Decision.

4. The 2023 Electric Resource Plan Application, filed by Tri-State on December 1, 2023, as modified by the Settlement Agreement, is granted.

5. This Recommended Decision shall be effective on the day it becomes the Decision of the Commission, if that is the case, and is entered as of the date above.

6. As provided by § 40-6-109, C.R.S., copies of this Recommended Decision shall be served upon the parties, who may file exceptions to it.

- a. If no exceptions are filed within 20 days after service or within any extended period of time authorized, or unless the decision is stayed by the Commission upon its own motion, the recommended decision shall become the decision of the Commission and subject to the provisions of § 40-6-114, C.R.S.
- b. If a party seeks to amend, modify, annul, or reverse basic findings of fact in its exceptions, that party must request and pay for a transcript to be filed, or the parties may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, the Commission is bound by the facts set out by the administrative law judge and the parties cannot challenge these facts. This will limit what the Commission can review if exceptions are filed.

7. If exceptions to this Decision are filed, they shall not exceed 30 pages in length, unless the Commission for good cause shown permits this limit to be exceeded.

(S E A L)



THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

Aviv Segev

Administrative Law Judge

ATTEST: A TRUE COPY

A handwritten signature in cursive script that reads 'Rebecca E. White'.

Rebecca E. White,
Director

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit AAA: Department, Order No. 202-26-19 (Mar. 23, 2026)



Department of Energy
Washington, DC 20585

Order No. 202-26-19

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 (U.S.) 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 were both slated to cease operations in December 2025.⁴

Order No. 202-25-12, issued pursuant to FPA section 202(c), required that Schahfer remain in operation for 90 days, through March 23, 2026. This order was 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 faced tight reserve margins due to well documented year-round resource adequacy concerns, particularly during periods of high

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 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.

demand or low generation resource output.⁵ I determined that the continued operation of Schahfer would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.⁶ I determined that the continued operation of Schahfer was necessary to alleviate immediate and anticipated threats to reliability.⁷

My determination was based on several facts.

First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, 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.”⁸ Additionally, the LTRA notes that “[t]he departure of MISO’s coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years.”⁹

Second, 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 (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.¹⁰ MISO justified this revision by explaining that “Reliability risks associated with [r]esource [a]dequacy have shifted from ‘Summer only’ to a year-round concern.”¹¹ 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.¹²

⁵ See, e.g., *Midcontinent Indep. Sys. Operator, Inc., and Northern Indiana Public Service Company*, Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

⁶ See, e.g., *id.* at 1–4.

⁷ See, e.g., *id.* at 5.

⁸ NERC, *2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

⁹ *Id.* at 44.

¹⁰ *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).

¹¹ *MISO Transmittal Letter*, FERC Docket No. ER22-495-000, at 3 (Nov. 30, 2021).

¹² *Id.* at 3–4.

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-25-12 continue, both in the near and long term.¹³ The production of electricity from Schahfer will continue to be critical to maintain reliability in MISO. MISO’s resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Schahfer operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 “MaxGen” event for MISO’s North and Central Regions due to generation outages, high demand, and transfer capability limits.¹⁴ From January 21–February 1, 2026, Schahfer operated at over 285 MW every day.¹⁵

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.”¹⁶ Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected risk of loss of load in the winter and spring seasons, which, although not as high as in the summer or fall, will nevertheless increase over time.¹⁷

¹³ Further, as noted in Order No. 202-25-12, as a coal-fired facility, it would be difficult for Schahfer 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. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If NIPSCO were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required so long as I determine a shortage exists. *See* Order No. 202-25-12 at 1.

¹⁴ *See* Midcontinent ISO on X, (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

¹⁵ U.S. Dep’t of Energy, *FACT SHEET: Energy Department Prevented Blackouts & Saved American Lives During Winter Storms*, (February 2026), <https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms>.

¹⁶ MISO, *Attributes Roadmap*, at 3 (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>.

¹⁷ *Id.* at 11.

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*.”¹⁸ 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.¹⁹ These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.²⁰ NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,²¹ stating that it faces significant reliability challenges as “projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements.”²² This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.²³ The 2025 NERC Long-Term Reliability Assessment notes that “MISO’s accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements.”²⁴ The report observes that winter peak periods are a particular concern, with projections showing “shortfalls in planned resources for winter peak periods.”²⁵ However, NERC also concluded that “risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high.”²⁶

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the “[p]otential for insufficient operating reserves

¹⁸ MISO, *MISO’s Response to the Reliability Imperative* (Updated February 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>.

¹⁹ *Id.* at 12.

²⁰ NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

²¹ *Id.* at 7.

²² *Id.* at 8.

²³ *Id.* at 43.

²⁴ *Id.* at 15.

²⁵ *Id.*

²⁶ *Id.*

in above-normal conditions.”²⁷ These findings were echoed in NERC’s 2024–2025 Winter Reliability Assessment, which noted that “[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO’s capacity market, or received lower winter accredited capacity.”²⁸

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 accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Indiana.²⁹

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey, which reported the degree to which expected capacity resources satisfy planning reserve margin requirements.³⁰ 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.³¹ 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 2030.³² It also projected similar results for MISO’s winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.³³

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.³⁴

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

²⁷ NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

²⁸ NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

²⁹ 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.

³⁰ OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025) <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

³¹ *Id.* at 2.

³² *Id.* at 7.

³³ *Id.* at 9.

³⁴ *Id.* at 7, 9.

increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.³⁵

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with almost another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, including Schahfer.³⁶

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, 2025.³⁷ 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.³⁸ 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.³⁹ Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order No. 202-25-12 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and

³⁵ *Id.*

³⁶ See *Electricity*, Energy Information Administration, Indiana Analysis, <https://www.eia.gov/states/in/analysis>.

³⁷ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

³⁸ *Id.* P 84.

³⁹ 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>.

extraordinary threat to our Nation’s economy, national security, and foreign policy.”⁴⁰ 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.”⁴¹ 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.”⁴²

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.”⁴³ 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.

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.”⁴⁴

⁴⁰ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

⁴¹ *Id.*

⁴² Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

⁴³ U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf>.

⁴⁴ *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcomm. on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), <https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/>

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.”⁴⁵ 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.”⁴⁶

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest.”⁴⁷ 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.

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Schahfer Units 17 and 18 shall be made available for operation through June 21, 2026.

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

- A. From March 24, 2026, 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

files/evo-media-document/witness-testimony_asthana_eng_grid-operators_03.25.2025.pdf.

⁴⁵ *Id.* at 6.

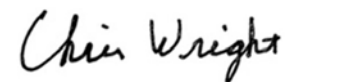
⁴⁶ *Id.* at 7.

⁴⁷ 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).

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 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 have operated in compliance with the allowances contained in this Order.
- C. All operation of Schahfer must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.
- D. By April 8, 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 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 March 24, 2026 through June 21, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of March 2026.



Chris Wright
Secretary of Energy

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

Indiana Utility Regulatory Commissioners
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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)
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)

Order No. 202-26-21

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

Exhibit B: Declaration of Josh Korth Declaration (Apr. 27, 2026)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

ORDER NO. 202-26-21

DECLARATION OF JOSHUA KORTH

I, Joshua Korth, declare under penalty of perjury pursuant to 28 U.S.C. § 1746, that the following is true and correct to the best of my knowledge:

1. I am a resident of the State of Colorado. I am over the age of 18 and have personal knowledge of all the facts stated herein, except to those matters stated upon information and belief; as to those matters, I believe them to be true. If called as a witness, I could and would testify competently to the matters set forth below.

2. As the supervisor of the State Implementation Plan ("SIP") Technical Development Unit within the Air Pollution Control Division of the Colorado Department of Public Health and Environment ("Air Division"), I submit this declaration in support of the State of Colorado's Request for Rehearing ("Request") of the Department of Energy's ("Department") Order No. 202-26-21 ("Renewed Order") regarding a coal-fired generating unit ("Craig Unit 1") at the Craig Station facility in Craig, Colorado.

Personal Background and Qualifications

3. I have been employed at the Air Division since 2019.
4. I received a Bachelor's Degree in Chemistry from Luther College in Decorah, Iowa in 2001.
5. I have been involved in environmental work, specifically air quality, within the electric utility industry during my entire professional career.
 - a. From 2001 to 2008, I was employed by Teledyne Monitor Labs, Inc., as a regulatory specialist. In that role I developed certification and quality assurance testing reports for clients who purchased and installed continuous emissions monitoring systems to meet local, State, and federal regulatory requirements.
 - b. From 2008 to 2011, I was employed by Environmental Systems Corporation as a senior air quality specialist. In that role, I assisted clients with interpreting Title V operating permits and consulted on the design of data acquisitions systems to collect and report air quality data for State and federal regulatory requirements.
 - c. From 2011 to 2019, I was employed by Public Service Company of Colorado ("Public Service") as an environmental analyst. In that role, I was responsible for documenting ongoing compliance with State and federal air quality requirements, developing air permit applications, and participating in rulemaking activities that could impact the utility sector.

6. The Air Division is charged with implementing the Federal Clean Air Act and the Colorado Air Pollution Prevention and Control Act. In my current role at the Air Division, I am responsible for leading teams that provide technical analysis and support for the development of SIPs required by the federal Clean Air Act and of Colorado air quality regulations.

7. The teams I lead collaborate with the Colorado Energy Office on the development of programs to achieve Colorado's greenhouse gas ("GHG") reduction goals. My teams also collaborate with, and testify before, the Colorado Public Utilities Commission ("CoPUC") related to emissions calculations and tracking as well as other air quality questions involving electric utilities.

8. The retirement of Craig Unit 1 by December 31, 2025 is required by Colorado's air quality regulations and the Federally approved Round 1 Regional Haze SIP, and aligns with many of Colorado's priorities and emissions reduction goals and obligations. Craig Unit 1's retirement was a carefully planned action toward emissions reductions in furtherance of compliance with federal law and achieving the State's goals. The Renewed Order unjustly and improperly interferes with this planning.

Department of Energy Renewed Order

9. I am familiar with the Renewed Order regarding Craig Unit 1.

10. The Air Division has the knowledge and expertise to advise on ways to best meet any actual electric emergency in Colorado while minimizing conflicts with environmental laws, specifically with environmental air quality laws. However, the Department did not attempt to consult with the Air Division to discuss any component of the Renewed Order, including to identify mechanisms to address the claimed

emergency while minimizing environmental impact or conflicts with local, State, or federal environmental laws or regulations.

11. It is my understanding that Craig Unit 1 was not in operation at the time of issuance of the initial Order No 202-25-14 (“Original Order”). The Air Division had been advised by the operator of an outage that occurred on December 19, 2025 due to a mechanical failure of a valve resulting in the unit going off-line. The Air Division had been further advised by the operator that repairs and maintenance were needed to Craig Unit 1 in order to bring the unit back online pursuant to the Original Order. As of the date of this Declaration, I understand that those repairs and maintenance have been completed to comply with the Original Order.

12. It is also my understanding that, during the duration of the Original Order, Craig Unit 1 was not called upon by either Western Area Power Administration (“WAPA”) or Southwest Power Pool (“SPP”) to operate and accordingly did not operate.

13. Forcing Craig Unit 1 to be made available and/or operate will negatively impact air quality in Colorado for a few reasons, including:

- a. Craig Unit 1’s startup and continued operation will result in harm to the environment, and the health and wellbeing of Coloradans through the emission of additional and unnecessary air pollution;
- b. Craig Unit 1’s startup and continued operation will violate State regulations, federal air quality plans, and the unit’s federally enforceable operating permit; and

- c. Craig Unit 1's startup and continued operation may harm Colorado's ability to comply with the federal Clean Air Act and meet statutory statewide GHG reduction targets.

I. Craig Unit 1 is a significant source of air pollution.

14. Craig Unit 1 is a significant source of particulate matter ("PM"), nitrogen oxides ("NOx"), sulfur oxides ("SOx"), carbon monoxide ("CO"), hazardous air pollutants ("HAPs"), and GHG emissions.

15. The relevant regulations and permits for Craig Unit 1 specify a "potential to emit[,]” as that term is defined by applicable laws of: 1,891 tons per year ("tpy") of PM; 435 tpy of PM10; 22,695 tpy of SO₂; 13,239 tpy of NOx; 60 tpy of volatile organic compounds ("VOC"); and 498 tpy of CO.¹

16. In April 2025, the operator reported emissions of numerous air pollutants from Craig Unit 1 for calendar year 2024 including: 86 tons of PM10; 49 tons of PM2.5; 335 tons of SOx; 2,176.6 tons of NOx; and 239 tons of CO. Craig Unit 1 also emitted non-criteria pollutants, including 2,391 pounds ("lbs") of cyanide and 7,204 lbs of manganese.² In January, 2026, the operator reported emissions of mercury for calendar year 2025 of 9.59 lbs.³

17. The December 31, 2025 scheduled retirement of Craig Unit 1 would have resulted in significant emissions reductions, reducing emissions by the amounts and

¹ Exhibit LL (Division, *Technical Review Document for Operating Permit 96OPMF155* (Jan. 2005)).

² See Exhibit MM (Tri-State, General APEN- Form APCD-200 (Apr. 21, 2025)).

³ Exhibit DDD (Letter from Jerome H. Sturhahn, Senior Vice President of Tri-State, to Shannon McMillian, Compliance and Enforcement Program Manager, CDPHE (Jan. 26, 2026)) at 3.

types of air pollutants described above as well as others identified in Craig Unit 1's 2025 updated Air Pollution Emission Notice ("APEN").

18. Craig Unit 1's startup and continued operation may also result in excess emissions. In the past, Craig Station has experienced numerous malfunctions that resulted in at least brief periods of emissions above permitted levels. If Craig Unit 1 continues to operate, more malfunctions may occur, which would result in even greater emissions beyond the additional emissions generated from Craig Unit 1 not retiring as planned.

19. If Craig Unit 1 continues to operate beyond its planned retirement date, it will continue to cause the emission of, and directly emit, air pollution in Colorado, which will further harm the environment, public health and welfare, as well as Colorado's ability to comply with other federal and State environmental laws.

II. Craig Unit 1's continued operation will harm the environment, and health and wellbeing of Coloradans.

20. Pollutants like PM, SO_x, GHG, NO_x, CO, and VOC harm the environment through their contribution to climate change and general pollution of the ambient air, which can cause visibility impairment, harms to public health, sensitive ecosystems and wildlife, heat waves, drought, severe wildfires, and flooding in Colorado and beyond.

21. The pollution from Craig Unit 1 contributes to climate change, which is already having dire effects on the State of Colorado, its people, and its natural resources. In recent years, the people of Colorado have suffered dramatic impacts from extreme heat, drought, wildfires, and flooding.

22. Emissions of criteria air pollutants such as PM10, PM2.5, CO, NOx, VOC, and SOx emitted by Craig Unit 1 may reduce visibility, harm wildlife, and contribute to public health impacts.⁴ Exposure to these pollutants may also increase risk of heart attacks, lung disease, respiratory problems, headaches, dizziness, and premature death.⁵

III. Craig Unit 1's continued operation will violate State and federal air quality regulations and its permit, and may hinder Colorado's ability to comply with other environmental laws.

23. While the Renewed Order requires Craig Unit 1 to comply with applicable environmental requirements "to the maximum extent feasible while operating consistent with the emergency conditions[,]"⁶ this direction is vague and unclear. Additionally, the Renewed Order's requirement in paragraph C to "minimize adverse environmental impacts [] [by] limit[ing] operation [] to the times and within the parameters identified in paragraph A and paragraph B"⁷ of the Renewed Order, is similarly vague and unclear. The Air Division cannot ascertain what the Department has determined are appropriate operating conditions to ensure conflicts with environmental laws and environmental impacts are minimized. Further, Craig Unit 1's continued operation will make cost-effective compliance with many State and federal air quality regulations infeasible.

24. Colorado and its sources of air pollution are required by certain State and federal regulations to reduce the amount of pollution emitted through measures

⁴ See Colorado Department of Public Health and Environment ("CDPHE"), [Regional Haze in Colorado](#) (2026); 42 U.S.C. § 7409; see also 40 C.F.R. § 50.

⁵ See CDPHE, [Regional Haze in Colorado](#) (2026).

⁶ Renewed Order, ¶ D.

⁷ *Id.*, ¶ C.

such as emission limits and controls and operational adjustments. Sometimes, in lieu of incurring the costs required to reduce emissions, operators will choose to retire older, high-emitting units like Craig Unit 1.

25. Craig Unit 1's continued operation will violate Air Quality Control Commission ("Air Commission") Regulation Number 23, Colorado's federally approved Regional Haze SIP, and its Title V Permit. Craig Unit 1's startup and continued availability and operation may further hinder the State's ability to comply with federal Clean Air Act requirements of both the National Ambient Air Quality Standards ("NAAQS") program and the Regional Haze program, as well as its ability to meet pollution reduction targets set out in State law.

26. *First*, Colorado's Air Commission adopted Craig Unit 1's retirement date of December 31, 2025 into Regulation Number 23.⁸ This provision of Regulation Number 23 is federally enforceable because it has been approved by EPA into Colorado's SIP.⁹

27. *Second*, EPA has adopted rules that require states to reduce emissions of visibility impairing pollutants that negatively impact Class I areas. Class I areas are areas designated as such to maintain natural conditions free from the adverse effects of air pollution because these areas may be home to sensitive ecosystems or species that could be harmed by even small increases in pollutants.¹⁰ Under the visibility program requirements, states must conduct detailed and expensive analyses, and

⁸ 5 Colo. Code Reg. § 1001-27.

⁹ Approval and Promulgation of Air Quality Implementation Plans; Colorado; Regional Haze State Implementation Plan, 83 Fed. Reg. 31332 (July 5, 2018); EPA, [EPA Approved Statutes and Regulations in the Colorado SIP](#) (Jan. 6, 2026).

¹⁰ CDPHE, [Regional Haze in Colorado](#) (2026).

based on the results of those analyses, impose federally enforceable controls and emission limits upon the largest and most impactful sources of haze pollutants. Colorado developed its Regional Haze SIP to fulfill these requirements. Colorado's Regional Haze SIP includes requirements for certain sources of air pollution to install pollution control technologies or take other actions to reduce emissions of NO_x, SO_x, and PM, as well as monitoring and reporting requirements for tracking visibility impairment and emissions reductions over time.¹¹ The Department did no analysis to assess the impact of its Renewed Order on Colorado's compliance with the federal Clean Air Act visibility program.

28. *Third*, major sources of air pollution are required to apply for and obtain a Title V operating permit, which is a federally enforceable permit containing conditions for operation, management, reporting, and recordkeeping. Craig Unit 1 is a major source of air pollution on its own. The Air Division issued the Craig Station a renewed Title V Operating Permit on July 1, 2021.¹² This Title V Permit includes emissions limits, operational requirements, reporting obligations, and other requirements to ensure the safe and environmentally sound operation of Craig Unit 1. Specifically, Condition 1.10. of Craig Unit 1's Title V operating permit requires the Unit to close on or before December 31, 2025. This date was agreed upon by the operator and the State to avoid the need for additional controls or conversion of the source to another fuel type as part of the Round 1 Regional Haze SIP and was later

¹¹ Exhibit NN (Division, *Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)).

¹² Exhibit KK (Division, *Operating Permit No. 96OPMF155* (July 1, 2021)).

incorporated into the operating permit. Both the SIP and the Title V permit have been reviewed and approved by the EPA.

29. *Fourth*, the federal Clean Air Act requires states to achieve attainment with NAAQS. Two of the criteria pollutants for which such standards are adopted include ozone and oxides of nitrogen. Oxides of nitrogen are also ozone precursor pollutants. Craig Unit 1 is a significant emitter of NO_x. The Air Division is not aware of any analysis the Department did to assess the impacts of the continued availability or operation of Unit 1 upon Colorado's ability to comply with and achieve the federal Clean Air Act's NAAQS attainment program. And the lack of detail and clarity in the Renewed Order as to when and how Craig Unit 1 will operate if and when called upon prevents the Air Division from doing its own analysis.

30. *Finally*, the Colorado Legislature adopted statewide GHG pollution reduction goals to achieve a 26% reduction by 2025; 50% reduction by 2030; 65% reduction by 2035; 70% reduction by 2040; 95% by 2045; and net-zero by 2050 as compared to 2005 levels.¹³ Craig Unit 1's planned retirement date of December 31, 2025 is a part of the State's larger plan to reduce GHG emissions to meet these statutory statewide targets. The Renewed Order, to the extent it requires Craig Unit 1 to startup and/or operate, will impede Colorado's ability to meet its statewide GHG reduction goals. The Air Division was not consulted by the Department in any analysis to assess Craig Unit 1's continued availability and operation upon these GHG reduction goals.

¹³ § 25-7-102(2)(g), Colo. Rev. Stat.

IV. Craig Unit 1's continued operation will result in more pollution and will incur more costs.

31. The December 31, 2025 retirement of Craig Unit 1 is an important part of the overall pollution reduction strategy in Colorado. Colorado's air quality agencies have worked with air pollution sources for decades to carefully plan efficient and reasonable emissions reductions to help the environment, public health and welfare, and to ensure a just transition for air pollution sources. The continued operation of Craig Unit 1 will not only disrupt this planning, but will also harm the environment, public health and welfare, and violate numerous federal and State air quality regulations. The Department did not consult with the Air Division as to whether and how Craig Unit 1 could be operated consistently with State or federal environmental requirements.

32. If Craig Unit 1 continues to be available and operate it should be required to comply with the maintenance, operational, and monitoring requirements of its Title V permit, which will result in additional costs to the operator outside of what was expected from a December 31, 2025 retirement date. The Department did not consult with the Air Division as to whether and how Craig Unit 1 could be operated consistent with the Title V permit.

33. It is unclear to the Air Division if there are adequate supplies of coal onsite to continue to operate Craig Unit 1 along with the other units at the facility. If there are inadequate supplies, the source of additional supplies of coal that will be used to continue to operate Craig Unit 1 is not known by the Division. Not all coal has the same emissions profile when combusted. Thus, the use of a different source of coal to continue to operate the units at the Craig Station may have an even greater

impact on air quality and public health than the use of existing supplies. The Department did not consult with the Air Division as to the quantification of these impacts or methods to minimize or mitigate them.

34. Further, the Air Division does not regulate and track all of the emissions associated with the transport of coal to the Craig Station. If additional coal must be delivered to the facility to support the continued operation of the coal units, this will result in additional emissions of air pollution from the mining, loading, transport, and unloading of the fuel that would not have otherwise occurred if Craig Unit 1 was retired as planned. Thus, without details in the Renewed Order, and an understanding of the actions that the operator will be required to undertake to comply with the Renewed Order, the Air Division cannot quantify the emissions impact from the acquisition and transport of any additional coal to the Craig Station resulting from the Renewed Order. The Department did not consult with the Air Division as to the quantification of these impacts or methods to minimize or mitigate them.

35. The Renewed Order's delay of the retirement of Craig Unit 1 will have negative regulatory, environmental, and health and welfare impacts on the State of Colorado.

I declare under penalty of perjury that, to the best of my knowledge, the foregoing is true and correct.

Executed this 27 day of April, 2026.

Joshua Korth Digitally signed by Joshua Korth
Date: 2026.04.27 07:58:25 -06'00'

Joshua Korth

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit BB: CoPUC, Decision No. C25-0892, issued on December 10, 2020,
in Proceeding No. 25V-0480E

Decision No. C25-0892

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 25V-0480E

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.

COMMISSION DECISION GRANTING JOINT PETITION WITH MODIFICATIONS AND ESTABLISHING PARTIES

Issued Date: December 10, 2025
Adopted Date: December 3 and 10, 2025

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Before the Public Utilities Commission of the State of Colorado

Decision No. C25-0892

PROCEEDING NO. 25V-0480E

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I. BY THE COMMISSION

A. Statement

1. Through this Decision we grant, with modifications, the Joint Petition that Trial Staff of the 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, “Joint Petitioners”) filed on November 10, 2025 (“Petition”). We specifically grant the requested variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761 to modify the planned retirement date of Comanche Unit 2 (“Pueblo Unit 2”) coal-fired facility from December 31, 2025, to December 31, 2026. In addition, we provide additional reporting and future filing direction regarding the proposed two-step process in the Petition and establish the parties to this Proceeding.

B. Background

2. On November 10, 2025, Joint Petitioners filed the Petition seeking a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761, and any other decisions the Commission

deems necessary, to modify the planned retirement date of Comanche Unit 2 (“Pueblo Unit 2”) from December 31, 2025, to December 31, 2026.

3. Through Decision No. C25-0812-I, issued November 12, 2025, the Commission granted the Petition’s request for a shortened notice and intervention period and established a deadline for responses to the Petition and replies to the responses. Interventions and responses, which were to be filed concurrently, were due on November 20, 2025, and any replies due on November 26, 2025.

4. Several parties filed timely motions to permissively intervene and responses on the November 20, 2025 deadline, and multiple public comments have been filed thus far.

5. Joint Petitioners filed a Joint Reply on November 26, 2025.

6. An unopposed late-filed motion to intervene was filed on December 2, 2025, by CORE Electric Cooperative (“CORE”).

C. Joint Petition

7. The Petition requests a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761.¹ The requested variance would extend the planned retirement date of Comanche Unit 2 from December 31, 2025, to December 31, 2026. The Joint Petitioners assert that good cause exists to grant the variance and that the limited modification is in the public interest. The Petition also requests a shortened notice and intervention period of ten days and proposes a procedural schedule to allow for Commission deliberation and action by December 10, 2025.

8. Joint Petitioners contend that recent events have resulted in challenges to the planned retirement. As set forth in the Petition, these events fall generally into four categories: (1) the impact of the extended outage of Pueblo Unit 3 on Public Service’s system; (2) increasing

¹ Issued September 10, 2018, in Proceeding No. 16A-0396E.

peak load growth in Public Service’s territory; (3) supply chain and geopolitical/macroeconomic impacts; and (4) reassessment of resource accreditation and planning reserve margin methodologies.

9. Joint Petitioners therefore seek relief in the form of a variance from the Commission’s directive to file a certificate of public convenience and necessity (“CPCN”) amendment to effectuate a retirement of the Pueblo Unit 2 by the end of this year, as well as any other requirements the Commission deems necessary.

10. Additionally, Joint Petitioners propose a two-step process for further evaluation in which the Company will provide two updates to the Commission on work in the extended review period. For the first step, the Company will provide a report to the Commission on March 1, 2026, which will include, among other things, an update on the repair and return to service status of Pueblo 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.

11. For the second step, the Company commits to submitting an application on June 1, 2026, which would consist of any additional variances or resource approvals building on the report and will include, among other things, updated loads and resources tables and loss of load calculations that include analysis of new resources projected to come on-line from the Company’s Near-Term Procurement, the Just Transition Solicitation (“JTS”) Phase II resource solicitation, or other relevant proceedings.

D. Establishment of Parties

12. Under Rule 1200(a)(I), 4 *Code of Colorado Regulations* (“CCR”) 723-1, parties shall include any person that initiates action through the filings of a complaint, application, or

petition. Therefore, Public Service, Staff, UCA, and CEO—as the Joint Petitioners—are parties to this Proceeding.²

13. The following parties filed timely motions for permissive intervention: the City of Boulder (“Boulder”); the Board of County Commissioners of Pueblo County, the City of Pueblo, and the Pueblo Economic Development Corporation (collectively, “Pueblo Intervenors”); GreenLatinos, GRID Alternatives, Ebony Advocates, NAACP Pueblo Branch, Roots to Resilience, and Vote Solar (collectively, the “Environmental Justice Coalition” or “EJC”); Western Resource Advocates (“WRA”); Colorado Energy Consumers (“CEC”); Natural Resources Defense Council and Sierra Club (collectively, the “Conservation Coalition”); the Colorado Renewable Energy Society (“CRES”); and Climax Molybdenum Co. (“Climax”).

14. Boulder is a home rule city and municipal corporation and a large customer of Public Service. Boulder states its residents and businesses are also customers of the Company and that it has a longstanding interest in proceedings affecting electric generation, greenhouse gas emissions, and customer rates. Boulder asserts its climate goals depend on the decarbonization of Public Service’s generation mix and that the early retirement of Pueblo Unit 2 was a key component of the Colorado Energy Plan portfolio it supported in the 2016 Electric Resource Plan (“ERP”). Boulder seeks to intervene to address the prudence, cost, and emissions implications of extending Pueblo Unit 2’s operation.

15. The Pueblo Intervenors state they have substantial tangible and pecuniary interests in the continued operation of Pueblo Units 2 and 3. Pueblo Intervenors assert these units provide critical electric service to the Pueblo Steel Mill, a major employer and economic driver in the region, and contribute significantly to local tax revenues. Pueblo Intervenors argue that the

² Staff reiterates this point in its Notice to Rule 1007(a), filed on November 20, 2025.

outcome of this Proceeding will directly impact the economic stability of the community and the viability of ongoing industrial operations in Pueblo. Pueblo Intervenors support the variance and seek to ensure that community interests are adequately represented.

16. EJC represents community members in Pueblo and assert that the continued operation of Pueblo Unit 2 would disproportionately harm a historically impacted community already burdened by pollution from the Pueblo coal plant. EJC opposes the Petition as filed and instead supports an Alternate Plan that includes operational limits on Units 2 and 3, enhanced transparency, and a more robust process for evaluating the future of Pueblo Unit 3. EJC emphasizes the Commission’s statutory equity mandate and urges action that prioritizes public health and environmental justice.

17. WRA is a nonprofit environmental advocacy organization focused on reducing greenhouse gas emissions and promoting clean energy across the Interior West. WRA states it has long participated in Commission proceedings, including the 2016 and 2021 ERP/Clean Energy Plan (“CEP”) proceedings, and that it joined the settlement agreements that established the early retirement of Pueblo Units 2 and 3. WRA asserts the proposed variance could undermine those agreements and increase emissions, and therefore seeks to ensure that any delay in retirement is narrowly tailored and accompanied by operational limits and transparency measures to protect public health, the environment, and ratepayers.

18. CEC is an unincorporated association composed of various industrial and commercial customers of Public Service. CEC states its members operate facilities within the Company’s service territory and are among its largest customers. CEC asserts the outcome of this Proceeding will directly impact its members’ electric rates and service reliability, particularly due to the proposed extension of Pueblo Unit 2’s retirement. CEC further states that it was a party to

the 2016 ERP and the 2021 ERP/CEP proceedings, and that the proposed variance would alter the assumptions underlying the Updated Settlement Agreement approved in those prior proceedings.

19. The Conservation Coalition is composed of two nonprofit environmental organizations with longstanding participation in Commission proceedings. The Conservation Coalition states it does not oppose a one-year variance for Pueblo Unit 2's retirement but objects to the breadth of the relief requested in the Petition. The Coalition supports an Alternate Plan that includes operational limits on combined generation from Pueblo Units 2 and 3, enhanced transparency and reporting, and a more timely and robust follow-on proceeding. The Conservation Coalition asserts its interests in environmental protection, public health, and ratepayer impacts would be substantially affected by the outcome of this Proceeding.

20. CRES is a nonprofit organization that promotes energy efficiency and renewable energy across Colorado. CRES states it represents a broad membership of individuals and businesses committed to accelerating the transition from fossil fuels to clean energy. CRES asserts that the proposed extension of Pueblo Unit 2's retirement would result in increased greenhouse gas and pollutant emissions and could delay the integration of renewable resources. CRES requests a more thorough, litigated process to evaluate the Petition and urges the Commission to ensure that any extension is supported by a complete evidentiary record.

21. Climax operates the Climax and Henderson molybdenum mines and is one of Public Service's largest electric customers. Climax states that its mining and milling operations depend on reliable and cost-effective electric service from the Company. Climax asserts that the outcome of this Proceeding will directly affect its operations due to potential impacts on system reliability and replacement power costs associated with the proposed extension of Pueblo Unit 2. Climax supports the requested variance with reservations and urges the Commission to clarify that

any costs incurred as a result of the extension or the Pueblo Unit 3 outage carry no presumption of prudence.

22. Pursuant to Rule 1401(c) of the Rules of Practice and Procedure, 4 CCR 723-1, persons seeking permissive intervention must show the following, in pertinent part:

A motion to permissively intervene shall state the specific grounds relied upon for intervention; the claim or defense within the scope of the Commission's jurisdiction on which the requested intervention is based, including the specific interest that justifies intervention; and why the filer is positioned to represent that interest in a manner that will advance the just resolution of the proceeding. The motion must demonstrate that the subject proceeding may substantially affect the pecuniary or tangible interests of the movant (or those it may represent) and that the movant's interests would not otherwise be adequately represented.

23. We find that each party entity seeking timely permissive intervention has sufficiently demonstrated that this Proceeding may substantially affect its pecuniary or tangible interests, as is required by Rule 1401(c). Each also has demonstrated that its interests would not otherwise be adequately represented. Therefore, we grant each of the timely unopposed requests for permissive intervention.

24. On December 2, 2025, CORE filed a late-filed Motion to permissively intervene in this Proceeding. CORE includes in its filing that it is a wholesale purchaser of electric power and energy from Public Service, is a joint owner of the Pueblo Unit 3 facility with Public Service and Holy Cross Electric Association, Inc., and has significant contractual and regulatory relationships with Public Service. Thus, CORE includes that its direct, tangible, and pecuniary interests will be materially affected by the outcome of this proceeding, specifying that a variance in Comanche Unit 2's retirement date and the impact, if any, on changes to Comanche Unit 3's operations will affect CORE and its members. CORE states that, while untimely, its intervention is unopposed and will not broaden the scope of the Proceeding. CORE states that, following consideration of

the responses filed by potential parties, some parties indicate possible expansion of the Petition's scope to request operational changes at Unit 3, which could impact CORE as a joint owner.

25. Pursuant to Rule 1401(a) of the Rules of Practice and Procedure, 4 CCR 723-1, the Commission may, for good cause shown, allow late intervention, subject to reasonable procedural requirements. We find that CORE's late-filed intervention will not broaden the scope of this Proceeding or its process and otherwise meets the intervention standard set forth in Rule 1401. Therefore, we grant CORE's late-filed intervention.

E. Party Responses

1. WRA

26. WRA supports a limited variance to extend the retirement of Unit 2 but conditions its support on the Commission's adoption of the "Alternate Plan,"³ which it developed in collaboration with the Conservation Coalition and the Environmental Justice Coalition. WRA summarizes the Alternate Plan as follows: (1) place a status quo operational limitation on the operation of Unit 2 and Unit 3, designed to limit the total, combined generation from Units 2 and 3 to 3,942,000 MWh in 2026; (2) provide transparent, regular reporting related to the continued operations of Unit 2 and Unit 3 and associated costs incurred; and (3) institute an appropriately accelerated process to determine Public Service's resource adequacy position, identify near-term solutions, and provide direction on the continued operation of Unit 2 and Unit 3.⁴

27. WRA emphasizes that the Alternate Plan is necessary to preserve the emissions reductions contemplated in prior Commission decisions and settlement agreements.⁵

³ Attachment WRA-1 Alternate Plan.

⁴ WRA Response at pp. 7-8.

⁵ WRA Response at p. 8.

The Plan proposes a combined generation cap of 3,942,000 MWh for Units 2 and 3 in 2026, consistent with the 60 percent annual capacity factor limit previously approved for Unit 3. WRA argues this cap is essential to prevent an increase in emissions beyond what was previously authorized and to maintain the integrity of the Commission's prior resource planning decisions.

28. In addition to operational limits, WRA requests that the Commission require monthly reporting on a range of operational and financial metrics, including hourly generation, emissions, and costs associated with the continued operation of Unit 2 and the outage of Unit 3.⁶ WRA also recommends that the Commission initiate a new application proceeding within 60 days of its decision on the Joint Petition to evaluate near-term resource adequacy and the future of Units 2 and 3.

29. Specifically, and as set forth in the Alternate Plan, WRA recommends the Company provide monthly reports on the 15th of each month with the following information:

- (1) The MW produced each hour that Comanche 2 and Comanche 3 were operating;
- (2) The total MWh produced by Comanche 2 and Comanche 3;
- (3) The total CO₂, SO_x, NO_x, and PM10 emissions produced by Comanche 2 and Comanche 3;
- (4) Any estimated future costs, and/or actual costs incurred, related to the outage of Comanche 3, including but not limited to repair costs and replacement energy costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred;
- (5) Any updates on the repair and return to service status of Comanche 3, including the expected date for resuming operation;
- (6) Any estimated future costs, and/or actual costs incurred, related to the extension of the life of Comanche 2, including but not limited to maintenance costs, return to operation and plant overhaul or upgrade costs, and fuel costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred; and,

⁶ WRA Response at pp. 12-13.

(7) Large Load Reporting:

- a. Information about actual load growth from large load customers, including MW and number brought online;
- b. Information about forecasted large load growth in the queue, including MW and number of large load interconnection requests and status (projected in-service date and load ramp forecast); and
- c. Information about large load requests that have exited the queue, including MW and number.⁷

30. In addition, WRA argues the Commission should adopt the accelerated procedural framework set forth in the Alternate Plan. WRA asserts that adopting the Petition's proposed timeline for Step 1 and Step 2 would limit the Commission's ability to direct the Company to pursue alternative solutions.⁸ Instead, through the Alternate Plan WRA recommends the Commission direct Public Service to file an application within 60 days of the Commission's final decision on the Petition. The purpose of such an application would be to receive Commission guidance on Public Service's near-term resource adequacy position for years 2026-2028 as well as on the future operation and life of Comanche 2 and 3. WRA contemplates that the Commission decision ruling on the application would address near-term capacity needs (2026-2028), whether to revise the retirement dates and operational restrictions for Unit 2 and 3, and the possible authorization for additional resource procurements.⁹

31. WRA strongly opposes the use of Unit 2 to serve new large loads, arguing that the Company's resource adequacy concerns stem solely from the outage of Unit 3 and not from broader system needs. WRA contends that the Petition's reliance on supply chain issues, load growth, and accreditation changes is an improper attempt to relitigate issues already addressed in the JTS and other proceedings.

⁷ WRA Response, Attachment WRA-1 at pp. 2-3.

⁸ WRA Response at p. 13.

⁹ WRA Response, Attachment WRA-1 at pp. 3-4.

2. Conservation Coalition

32. Conservation Coalition requests the Commission deny the Petition and adopt the Alternate Plan, which is supported by Conservation Coalition, WRA, and EJC. Conservation Coalition states it does not object to a one-year variance from the requirements to retire Unit 2, but argues the Alternate Plan is necessary to resolve three problems with the Petition. First, Conservation Coalition argues the Petition would allow Unit 2 and Unit 3 to be run simultaneously with no limit on generation or emissions. Second, Conservation Coalition contends the Petition's proposition that the application proceeding to investigate dealing with near-term resource needs would not be filed until June 2026. Third, Conservation Coalition argues the Petition fails to address whether it is in the public interest to repair Unit 3 given its long-standing reliability and cost overrun issues.¹⁰

33. Conservation Coalition argues the only procedural and substantive basis for extending Unit 2 is the unexpected outage of Unit 3. They argue that Unit 3's outage is the new information that was not available during the JTS. According to Conservation Coalition, the other arguments put forth in the Petition—the increase in the Company's load forecast over time; supply chain and geopolitical delays in procuring resources from the 2021 ERP/CEP; and changes to the resource accreditation and planning reserve margin—are all improper attempts to relitigate issues that were addressed in the JTS.¹¹ Conservation Coalition states the Unit 3 outage is the only legally permissible basis for granting a variance, and Conservation Coalition reserves their rights to challenge a decision that grants a variance for any other reason.¹² Given that the only legitimate justification for extending Unit 2 is the unexpected outage at Unit 3, Conservation Coalition argues

¹⁰ Conservation Coalition Response at pp. 1-2.

¹¹ Conservation Coalition Response at pp. 3-4.

¹² Conservation Coalition Response at p. 5.

that the combined generation from Unit 2 and 3 in 2026 must not be allowed to exceed what is permitted from Unit 3 in 2026.¹³

34. Conservation Coalition also argues that the two-step process proposed in the Petition—consisting of a March 1, 2026 report and a June 1, 2026 application—is insufficient and untimely. The Coalition characterizes the proposed timeline as “too little, too late” and asserts that the Commission should instead initiate a litigated proceeding as soon as possible to evaluate the least-cost, lowest-emission options for the continued operation or retirement of Pueblo Units 2 and 3 after 2026.¹⁴ The Coalition contends that such a proceeding should address whether Unit 3 should be repaired at all, whether Unit 2 should continue to operate in lieu of Unit 3 after 2026, and what near-term capacity or energy needs exist, along with the most appropriate options for meeting those needs.¹⁵

35. According to Conservation Coalition, the Petition contemplates that Public Service may seek another variance in June 2026 to extend Unit 2’s operation beyond 2026. Conservation Coalition notes that such a request would come only six months before the end of 2026 and would replicate the rushed nature of the current proceeding. In contrast, the Alternate Plan would provide the Commission with a more proactive and structured opportunity to evaluate near-term needs and the future of Units 2 and 3. The Conservation Coalition further observes that the June 2026 filing would occur after Unit 3 is expected to return to service, thereby presuming the prudence of the repair before the Commission has had an opportunity to evaluate alternatives. This timing, they argue, would also delay the acquisition of any necessary replacement resources.¹⁶

¹³ Conservation Coalition Response at p. 7.

¹⁴ Conservation Coalition Response at p 9.

¹⁵ Conservation Coalition Response at p. 10.

¹⁶ Conservation Coalition Response at p. 10.

36. Conservation Coalition also objects to the June 2026 filing framework on the grounds that it would leave the scope of the proceeding entirely to the discretion of the Company. Conservation Coalition urges the Commission to provide clear direction on the topics that must be addressed and the alternatives that must be modeled. Under the Alternate Plan, the Company would be required to present testimony and modeling results addressing updated estimates of energy and capacity needs for 2026 through 2028; an assessment of all reasonable supply-and demand-side options for meeting those needs; and modeling of portfolios that include new options for Units 2 and 3, such as early retirement or seasonal operations, compared to baseline expectations.¹⁷ Conservation Coalition clarifies that the modeling should include scenarios such as extending Unit 2's operation beyond 2026 while retiring Unit 3 earlier than currently planned—*e.g.*, in 2028 or 2029—with or without seasonal operation of Unit 3 prior to retirement.

37. Conservation Coalition concludes by reiterating that the Commission should find there is no presumption of prudence for any costs associated with repairing Unit 3. They request that Public Service be required to notify the Commission of the estimated cost to repair Unit 3 before incurring such costs. Conservation Coalition further recommends that the Commission place the Company on notice that if it proceeds with repairs prior to conducting a modeling analysis demonstrating that such repairs are the least-cost option relative to alternatives, the Company may be at risk of a future disallowance.

3. EJC

38. EJC similarly recommends the Commission not approve the Petition but instead approve the Alternate Plan developed and supported by WRA, Conservation Coalition, and EJC. EJC argues that extending the life of Unit 2 will harm disproportionately impacted (“DI”)

¹⁷ Conservation Coalition Response at pp. 13-14.

communities in Pueblo., and states the Pueblo coal plants have emitted large amounts of pollution into the nearby community for more than five decades. EJC asserts that retiring Units 2 and 3 as planned will benefit the Pueblo community and reduce the pollution burdens that Pueblo has experienced since the 1970s.¹⁸

39. EJC notes that, under Senate Bill 21-272, the Commission has a statutory duty to minimize harms and correct the historical inequities experienced by DI communities such as Pueblo. To comply with its statutory equity mandate, EJC argues the Commission must thoroughly consider alternatives to address the outage of Unit 3 and approve an option that would best provide equity, address the historical inequalities, and minimize impacts and prioritize benefits in Pueblo. According to EJC, such alternatives include requiring operating guardrails that limit the overall generation at Unit 2 and Unit 3, utilizing market purchases while Unit 3 is offline, and reassessing the retirement date of Unit 3.¹⁹

4. City of Boulder

40. Boulder argues the requested variance is the result of Public Service's inability to properly operate Unit 3, asserting there is no evidence suggesting that, but for Unit 3's outage, this variance would be necessary. Boulder notes the Joint Petitioners do not request the acquisition of any other generation resources to address the four identified events, and that the Joint Petitioners claim the cost to buy market power is higher than the cost to continue operations at Unit 2, yet provide no evidence or financial analysis to support this conclusion.²⁰

41. Boulder agrees that the unplanned outage of Pueblo Unit 3, combined with delays in implementing new generation from the 2021 ERP/CEP, has left customers vulnerable to

¹⁸ EJC Response at p. 4.

¹⁹ EJC Response at pp. 6-8.

²⁰ Boulder Response at p. 3.

capacity shortfalls in 2026. Nevertheless, Boulder recommends that the Commission adopt several conditions to ensure ratepayer protection and to provide greater clarity regarding the Company's future resource planning.²¹

42. Boulder argues that ratepayers should be shielded from the cost increases associated with the failure of Unit 3 and the proposed extension of Unit 2. Specifically, Boulder recommends that the Commission prohibit Public Service from recovering any incremental costs related to the continued operation of Unit 2 or the repair of Unit 3 unless and until the Company demonstrates prudence in a future proceeding.²² Boulder also supports the proposed March 1, 2026 Step 1 report and encourages the Commission to use that report to evaluate updated retirement dates for Pueblo Unit 3 and to explore additional demand response and distributed energy resources as near-and mid-term solutions.²³ However, Boulder expresses concern that the proposed June 1, 2026 Step 2 application timeline is unrealistic, and argues that the timeline does not allow sufficient time for the Commission to approve new resources and for those resources to be acquired and placed in service in time to address any capacity shortfall in 2026.²⁴ Boulder also notes that while the Petition suggests Public Service may seek expedited approval to acquire new resources, it fails to explain how such acquisitions would be feasible outside of the typical ERP, demand-side management, or renewable energy standard proceedings.²⁵

43. Boulder further contends that the Joint Petitioners have not provided sufficient evidence to support their claim that a resource gap exists or that extending Unit 2 is the most cost-effective solution. Boulder recommends the Commission resolve these issues of Petition

²¹ Boulder Response at p. 6.

²² Boulder Response at p. 7.

²³ Boulder Response at p. 7.

²⁴ Boulder Response at p. 7.

²⁵ Boulder Response at p. 8.

adequacy before issuing a decision and certainly before the June 1, 2026 application is filed.²⁶ In addition, Boulder recommends that Public Service be required to acquire generation and storage resources to replace Unit 3 prior to its currently scheduled retirement date of January 1, 2031, and suggests that the Near-Term Procurement and JTS solicitations could be used to accomplish this.

44. Additionally, absent clear evidence in the Step 1 report that Unit 3 can return to service before the end of 2026, Boulder recommends that the Commission order Unit 3's immediate retirement.²⁷ Boulder also proposes that the Commission declare Unit 3 no longer "used and useful" and prohibit Public Service from earning its authorized return on equity until the plant is either returned to reliable operation or retired. Finally, Boulder encourages the Commission to consider a financial remedy to address the costs ratepayers have incurred due to the now-aborted retirement of Unit 2 and the Company's mismanagement of Unit 3.

5. CRES

45. CRES requests a hearing, discovery, and answer testimony to allow due process to investigate the Petition's claims. CRES acknowledges that such a fully litigated process would extend through the end of 2025 when Unit 2 is scheduled to retire and concludes that it may be prudent to grant the Petition only until more information is available and the evidentiary record for this Proceeding is complete.²⁸

46. CRES also notes that allowing the 335 MW Unit 2 to continue operating for even one more year will emit a large amount of carbon dioxide and other harmful pollutants into the Pueblo community and surrounding area. Given the considerable consequences for air quality and

²⁶ Boulder Response at p. 8-9.

²⁷ Boulder Response at p. 10.

²⁸ CRES Response a p. 5.

public health, CRES requests that the Commission ensure that the Petition's claims are substantiated through a more traditional litigated proceeding.²⁹

6. CEC

47. CEC argues that Unit 2's extension would not be necessary but for Unit 3's persistent operational failures, and generally supports granting the Petition to allow Unit 2 to continue operating, but argues the Commission should condition such a grant on several conditions.

48. CEC recommends the Commission impose several conditions to protect ratepayers from the financial consequences of Unit 3's outage. CEC notes that in prior instances of Unit 3 failures, the Commission has ordered disallowances through the Energy Cost Adjustment ("ECA"), and asserts that similar treatment is warranted here, where Unit 2 is being extended to serve as replacement power for Unit 3.³⁰ CEC argues there should be no presumption of prudence for any costs associated with Unit 2's extended operation, and that all costs related to Unit 3's outage should be disallowed. CEC recommends that the Company absorb all replacement power costs, including those associated with Unit 2, and return those costs to customers through the deferred balance in the next applicable ECA filing.

49. Specifically, CEC requests that the following rate-related conditions apply to the grant of the Petition: (1) all costs and investments associated with Unit 2's extended operation should be denied any presumption of prudence and evaluated in Public Service's next Phase I electric rate case; (2) Public Service must exclude from its revenue requirement all costs and expenses associated with Unit 3's outage in the test period, including gross plant, depreciation,

²⁹ CRES Response a p. 5.

³⁰ CEC Response at p. 6.

insurance, labor, and operations and maintenance; (3) Public Service must absorb all replacement power costs, including those from Unit 2 and any third-party sources, and flow those costs back to customers through the ECA; and (4) Public Service must include Unit 2's extended operation and emissions in any CEP compliance calculations and future emissions performance incentive mechanisms.³¹

50. CEC also raises concerns about the risk of over-procurement and overpayment for resources, given that the 2021 ERP/CEP modeling assumed Unit 2 would retire at the end of 2025. CEC warns of a scenario in which Public Service could simultaneously earn a return on Unit 2's extended operation, Unit 3 (once operational), and any new Company-owned generation approved to replace Unit 2. CEC questions whether the approved resource portfolio remains cost-effective in light of Unit 2's continued operation.³²

51. To address these concerns, CEC recommends the Commission impose additional resource planning conditions as part of granting the variance. These include: (1) requiring Public Service to evaluate its loads and resource needs, accounting for Unit 2's extension and the results of the Near-Term Procurement, before commencing the JTS Request for Proposals; (2) requiring Public Service to evaluate and report on how the extension of Unit 2 affects the cost-effectiveness of its selected portfolios from the Company's 2021 ERP/CEP,³³ as modified by the CEP Delivery Plan and Near Term Procurement results; and (3) granting any other relief the Commission deems necessary to hold ratepayers harmless from the effects of Unit 3's inoperability.³⁴

³¹ CEC Response at pp. 6-7.

³² CEC Response at p. 10.

³³ Proceeding No. 21A-0141E.

³⁴ CEC Response at p. 7.

7. Climax

52. Climax supports granting the variance to extend Unit 2's retirement date to December 31, 2026, but argues the Petition lacks any substantial evidence to support the prudence or reasonableness of any costs associated with Unit 2's extension. Climax argues the Commission should clearly state that all costs incurred as a result of the Unit 3 outage and Unit 2 extension carry no presumption of prudence. If the Company proposes to recover these costs, it must clearly identify and distinguish them. According to Climax, Public Service must have the burden of proving such costs are not redundant or otherwise unreasonable or imprudent.³⁵

8. Pueblo Intervenors

53. Pueblo Intervenors support the Petition, including the request to continue the operations of Unit 2 through next year and the expedited process and reporting requirements. They argue that the Company is facing a severe capacity shortage, and the Pueblo Steel Mill, an important industrial business in Pueblo, requires firm reliable electricity. Pueblo Intervenors argue the Company has been warning the Commission about its resource adequacy issues since February 2025 and that it would be reckless and dangerous to close Unit 2 with this type of resource shortage.³⁶

54. Pueblo Intervenors further assert the coal units in Pueblo are necessary to provide electricity to one of the largest employers in the Pueblo Area—the Pueblo Steel Mill. They acknowledge the Pueblo Steel Mill is partly powered by a solar array and electric arc furnace but assert it still requires at times electricity from the Pueblo station.³⁷ Pueblo Intervenors add that

³⁵ Climax Response at p. 4.

³⁶ Pueblo Intervenors Response at pp. 2-3.

³⁷ Pueblo Intervenors Response at p. 4.

Unit 2 and the Pueblo Steel Mill provide family supporting jobs, and assert the continued operation of Unit 2 alone will also provide approximately \$2.5 million a year in taxes for an additional year.³⁸

9. Public Comments

55. The Commission received numerous public comments regarding the Petition reflecting a wide range of perspectives. Several environmental and community organizations, including 350 Colorado and Colorado Communities for Climate Action (“CC4CA”), oppose the extension of Unit 2 and call for stronger safeguards. 350 Colorado argues that the Petition lacks transparency and data, and characterizes it as an attempt to relitigate the JTS. The organization urges the Commission to deny the Petition or, at a minimum, require additional information before making a decision. CC4CA acknowledges that extending Unit 2 may be unavoidable but recommends that the Commission prohibit simultaneous operation of Units 2 and 3, cap cost recovery from ratepayers, and consider accelerating the retirement of Unit 3 if operational issues persist.

56. Other commenters, including the International Brotherhood of Electrical Workers (“IBEW”) Local 111 and Colorado Concern, support the Petition. IBEW argues that closing Unit 2 at the end of 2025 would be reckless given current capacity shortages and emphasizes the importance of the jobs supported by the plant. Colorado Concern highlights the need for reliability and affordability amid rising energy demand and argues that approving the Petition demonstrates a disciplined approach to the energy transition. Several individual commenters also weighed in, with some expressing concern about ratepayer impacts and pollution, while others emphasized the need for reliable power and supported the extension.

³⁸ Pueblo Intervenors Response at p. 7.

57. Through its late-filed intervention and response, CORE claims that the Petition narrowly seeks a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761, and any other decisions the Commission deems necessary to modify the plan to retire Pueblo Unit 2 from December 31, 2025 to December 31, 2026. CORE recognizes the importance of the continued operation of Pueblo Unit 2 to meet the needs of Public Service customers and does not object to the modification of the plan to retire Pueblo Unit 2 as requested. However, CORE argues that any consideration to changing the operations at Pueblo Unit 3 are outside the scope of the Petition's request and would require a separate application to allow for adequate time for all parties to prepare to respond and provide meaningful evidence.

F. Joint Reply

58. The Joint Reply states that few intervenors oppose the requested relief but rather most parties raise recommendations outside the narrow scope of this Proceeding. More specifically, the Joint Reply observes how several intervenors raise ratemaking issues, including arguments that the costs associated with repairing Unit 3 and extending Unit 2 should not receive a presumption of prudence. The Joint Reply notes, however, that the Petition does not seek a presumption of prudence but expressly states the Petitioners do not seek any ratemaking relief.³⁹

59. The Joint Reply argues that issue of cost recovery associated with replacement power should be deferred to the relevant ECA and Purchased Capacity Cost Adjustment ("PCCA"). The Joint Reply adds that replacement power costs are currently unknown.

60. The Joint Petitioners oppose intervenor recommendations for additional reporting and an application filing prior to June 2026. The Joint Petitioners argue the two-step

³⁹ Joint Reply at pp. 2-3.

process—with a report in March and an application filing in June—is specifically designed to provide the Commission with an analysis of new resources projected to come on-line from the Near Term Procurement, JTS Phase II resource solicitation, or other relevant proceedings. In addition, the two-step process proposes to address operational concerns by first assessing operational parameters in Step 1 and giving the Company time to develop data-based recommendations to include in the application described in Step 2. The Joint Petitioners argue that—unlike the expedited track of the Alternate Plan—the June 1, 2026 application (Step 2) allows time to develop comprehensive solutions, for parties to provide meaningful input on these solutions, and for the Commission to consider alternatives. The Joint Petitioners add that neither the two-step process nor the Alternate Plan framework moves quickly enough to review options for Summer 2026 capacity needs.⁴⁰

61. Regarding the monthly reporting the Alternate Plan requests, the Joint Petitioners agree that reporting is important. They argue, however, that so is taking time to assess options and present the result of that assessment to the Commission. They argue the cadence of the two-step process balances the need for reporting with the work required to assess and develop a plan to address resource adequacy needs. Nevertheless, in the Joint Reply the Company agrees to incorporate the reporting requested in the Alternate Plan in the Step 1 March report and the Step 2 June application filing, to the extent such information is available.⁴¹

62. The Joint Petitioners also oppose the Alternate Plan’s operational limits on Unit 2 and Unit 3. They argue that addressing such operational limits is premature. The Joint Petitioners assert the Alternate Plan proposes the operational limits “without any analysis of current system

⁴⁰ Joint Reply at p. 6.

⁴¹ Joint Reply at p. 5.

conditions or Comanche Unit 2's operating capabilities, and without taking into consideration the needs of the Company's system operators."⁴²

63. The Joint Petitioners warn the Commission against relying on the loads and resources table put forth by WRA and Conservation Coalition, two of the three supporters of the Alternate Plan. They argue the loads and resources table has not been validated and it relies on assumptions that are likely to be contested in the fully adjudicated JTS proceeding.⁴³ More broadly, the Joint Petitioners caution against solely focusing on a loads and resources table when other metrics such as loss of load calculations are also relevant. The Joint Petitioners likewise ask the Commission to reject arguments that the Petition tries to improperly relitigate issues that could have been raised in the JTS. They note the JTS Phase I proceeding is still moving forward with RRRs and that the Petition's requested relief is narrow.⁴⁴

G. Findings and Conclusions

1. Unit 2's Extension

64. Consistent with the Petition, we grant the requested variances from Ordering Paragraphs 1 and 2 of Decision No. C18-0761 to modify the planned retirement date of Pueblo Unit 2 from December 31, 2025, to December 31, 2026. Extending Unit 2 is consistent with the arguments from Pueblo Intervenors and certain public commenters emphasizing the importance of reliable electricity. With this determination, we reject requests from CRES and others for a hearing, discovery, and answer testimony prior to a year-long extension of Unit 2. Such due process will be afforded in subsequent proceedings, including the Step 2 application filing and when Public Service seeks to recover costs associated with Unit 3's outage and the

⁴² Joint Reply at p. 4.

⁴³ Joint Reply at p. 6.

⁴⁴ Joint Reply at p. 7.

extension of Unit 2. Given the prolonged, unplanned outage of Unit 3, we must move swiftly to allow Unit 2 to continue operating, but doing so in no way impedes the Commission from later finding that Public Service acted imprudently. Consistent with Climax's recommendations, if Public Service intends to recover the costs associated with Unit 3's breakdown and Unit 2's extension, the Company will have the burden of proving such costs are not redundant or otherwise unreasonable or imprudent.

65. As part of our decision to grant the requested variance, we find that Unit 3's prolonged, unplanned outage is the single justification for extending Unit 2. As set forth by intervenors like WRA, Conservation Coalition, Boulder, and CEC, the Joint Petitioners have failed to demonstrate that the other reasons set forth in the Petition—supply chain and geopolitical issues, changes to the Company's resource accreditation methodology, and increasing peak demand—justify Unit 2's extension.

66. Regarding increasing peak demand, the most recent forecast provided in the Petition shows a 2026 peak demand of about 7,150 MW.⁴⁵ However, the Company's preferred updated base forecast that it endorsed in the JTS Rebuttal had a higher 2026 peak demand of 7,235.⁴⁶ Even though the Company had a higher demand forecast in its JTS Rebuttal, Public Service never requested or even suggested that it would need to extend Unit 2 to maintain resource adequacy. To be sure, Public Service raised concerns with its capacity position in recent proceedings, including in the JTS, but the Company never suggested the retirement date of Unit 2 should be reconsidered until now. An extension of Unit 2 was unnecessary until Unit 3 suffered its prolonged outage.

⁴⁵ Petition at p. 5.

⁴⁶ Hr. Ex. 117, Ihle Rebuttal, p. 30 filed in Proceeding No. 24A-0442E.

67. A similar analysis applies to the Petition’s arguments regarding supply chain and geopolitical issues and modifications to its resource accreditation methodology. The Petition provides no new evidence regarding supply chain and geopolitical issues but simply states that “[t]he Company addressed this in the CEP Delivery Plan in September 2024.”⁴⁷ The Petition adds that while the CEP Delivery Plan assists with geopolitical and supply chain issues, it does not cure them. Although not recounted in the Petition, geopolitical and supply chain issues were also an issue in the JTS—as demonstrated by issues such as the tariff passthrough mechanism the Phase I Decision adopts. In neither the CEP Delivery Plan nor the JTS did Public Service raise the possibility that geopolitical and supply chain issues could necessitate the extension of Unit 2. Again, Unit 2’s extension was unnecessary until Unit 3 went down.

68. The Petition similarly provides no new information regarding the modified resource accreditation methodology. Instead, the Petition recounts how it worked with a consultant in the JTS proceeding to update its resource accreditation methodology. The Petition does not indicate that there have been subsequent changes since the JTS Phase I Decision but simply states that the updated resource accreditation methodology “affects the Company’s loads and resource balance.”⁴⁸ Although the Company cited its updated resource accreditation methodology in both the CEP Delivery Plan and the JTS as a justification for additional resources, Unit 2’s extension was never raised as a potential solution until Unit 3 broke down.

2. Two-Step Process

69. On balance, we largely adopt the two-step process put forth in the Petition. This includes the March 1, 2026 report and analysis (Step 1) and the application filing the

⁴⁷ Petition at p. 5.

⁴⁸ Petition at p. 6.

Company must file no later than June 1, 2026 (Step 2). Although we share the frustrations expressed by several intervenors with the June 2026 date for the Step 2 application filing, we are sensitive to the Company, CEO, UCA, and Staff's timeline recommendations. In addition, even with an early 2026 filing as the Alternate Plan requested, the Commission would likely not be in a position to proactively determine whether repairing Unit 3 is prudent given the Company's expectations that Unit 3 will be fully repaired and return to service in June 2026. To be clear, the Step 2 application filing must be filed no later than June 1 2026, but we encourage and would accept earlier filings. The decision not to make earlier filings may in and of itself be imprudent if there are approvals or actions the Company should have raised earlier to the Commission and for party consideration.

70. While we do not require the expedited application filing requested in the Alternate Plan, we again emphasize that there is no presumption of prudence at this time for the repair of Unit 3 or operation of Unit 2. Public Service cannot assume that repairing Unit 3 is a prudent approach if better alternatives are available. For example, if continuing to operate Unit 2 through 2030 together with market purchases and additional demand side resources is a more cost-effective option than repairing Unit 3, Public Service would be at risk for disallowance if it brings Unit 3 back to service.⁴⁹ This is consistent with Boulder's recommendation to specifically seek out demand response and distributed energy resources to meet near- and mid-term resource adequacy. In sum, it appears the Company has decided to repair Unit 3 without first seeking guidance from the Commission—despite the plant's well-documented reliability issues, the fact that Unit 3 is slated to retire in January 2031, and the fact that the settlement agreement from the 2021 ERP

⁴⁹ Even aside from the issue of whether there are better alternatives to repairing Unit 3, Public Service may be at risk for disallowance if the Commission finds that the Company's imprudent operation of the plant led to its outage.

significantly limits the plant's annual capacity factor in its remaining years of life. Public Service's strategy on Unit 3 puts the Company at risk if its actions are later found to be imprudent.

71. Nevertheless, we are not deciding at this juncture to disallow the replacement power costs and repair costs associated with Unit 3's outage. Doing so here would be premature. We thus deny CEC's request to apply several rate-issue conditions such as directing that the Company exclude from its revenue requirement in the next electric rate case all costs and expenses associated with Unit 3's outage as well as Boulder's recommendations to prohibit cost recovery associated with any incremental costs of extending Unit 2's operations or repairing Unit 3. While the Commission may ultimately disallow such costs, Public Service does not request cost recovery in this Proceeding, and we lack the necessary information to make such findings.

3. Additional Reporting

72. Although we mostly accept the Petition's proposal for the two-step process, we find intervenor arguments regarding the need for additional reporting persuasive. In particular, we largely adopt the requested reporting set forth in the Alternate Plan. The Joint Petitioners provide little reasoning for their opposition to the reporting requests, but they imply that such reporting will leave insufficient time to assess options and present the results of that assessment to the Commission.⁵⁰ We find, however, that the requested reporting information will likely prove useful in future proceedings, including cost-recovery proceedings and the June 1, 2026 application proceeding. Proactively providing this information to the parties will hopefully make such future proceedings more expedient and effective. We acknowledge the Company's statement that it will include the requested information in the Step 1 and Step 2 filing, to the extent available, but we are persuaded that monthly reports will be more helpful to the Commission and parties.

⁵⁰ Joint Reply at p. 5.

73. While we generally adopt the cadence and substance of the reporting set forth in the Alternate Plan, we find certain clarifications to be necessary. First, we clarify that any estimated material future capital costs for the repair of Unit 3 must be reported to the Commission before such costs are obligated. Second, for the information concerning large loads, Public Service must include such data in the same format as it presented in the JTS proceeding in which each large load is correlated to its industry, the probability of the load materializing, the requested in-service date, and the forecasted load by year through 2040.⁵¹ In addition, out of all of the large loads listed, Public Service must clearly identify those that meet the Phase I Decision's requirements to be included in the base load forecast (*e.g.*, those loads that have executed an electric service agreement and interconnection agreement with the commercial principles including the fair notice provision).⁵²

74. Thus, Public Service shall provide monthly reports beginning on January 15, 2026, that contain the following information:

- The MW produced each hour that Unit 2 and Unit 3 were operating;
- The total MWh produced by Unit 2 and Unit 3;
- The total CO₂, SO_x, NO_x, and PM₁₀ emissions produced by Unit 2 and Unit 3;
- Any estimated material future capital costs for the repair of Unit 3, before they are obligated;
- Any additional future or actual costs incurred related to the outage of Unit 3, including but not limited to repair costs and replacement energy costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred;
- Any updates on the repair and return to service status of Unit 3, including the expected date for resuming operation;

⁵¹ See Hr. Ex. 141, Updated Base Forecast Large Load filed in Proceeding No. 24A-0442E.

⁵² See Decision No. C25-0747 at ¶ 68 issued in Proceeding 24A-0442E on November 6, 2025.

- Any estimated future costs, and/or actual costs incurred, related to the extension of the life of Unit 2, including but not limited to maintenance costs, return to operation and plant overhaul or upgrade costs, and fuel costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred; and,
- Large Load Reporting:
 - a. Information about actual load growth from large load customers, including MW and number brought online;
 - b. Information about forecasted large load growth in the queue, including MW and number of large load interconnection requests and status (projected in-service date and load ramp forecast); and
 - c. Information about large load requests that have exited the queue, including MW and number.⁵³

75. The Commission emphasizes that simply complying with these reporting requirements does not constitute a request for Commission approval. As a corollary, any Commission inaction regarding the submitted information is in no way tacit approval of the information or expenditures. If Public Service desires Commission guidance on its activities regarding Unit 3's outage, the Company must make an appropriate application filing.⁵⁴

76. In addition to the reporting set forth above, Public Service shall describe in its March 1, 2025, Step 1 report whether the outage at Unit 3 and the continued operation of Unit 2 impairs the ability of the Arroyo 2 solar facility—or any other resource—from delivering energy as planned. For instance, it appears the Arroyo 2 solar project was designed to use the same transmission capacity as Unit 2: “The Arroyo 2 Project ... will utilize the replacement interconnection rights that will become available due to the planned retirement of Comanche Unit 2 at the end of 2025.”⁵⁵ If Arroyo 2 or any other resources cannot be operated as planned due

⁵³ See WRA Response, Attachment WRA-1 at pp. 2-3.

⁵⁴ Should the Commission require additional information, process, or directives regarding the Step 2 application filing or other necessary direction following review of the reporting provided, it will do so through separate order, if needed.

⁵⁵ Hr. Ex. 101, Pascucci Direct, p. 11 filed in Proceeding No. 24A-0140E.

to Unit 3's outage or while Unit 2 is operating, this is potentially another cost of Unit 3's breakdown that Public Service must track.

4. Operational Limitations on Unit 2 and Unit 3

77. One of the main requests of the Alternate Plan backed by WRA, Conservation Coalition, and EJC, is to place an operational limitation on Unit 2 and Unit 3 so that the two units together could not generate more than 3,942,000 MWh in 2026. This 3,942,000 MWh limit is what Unit 3 could produce in 2026 given its 60 percent annual capacity factor limit agreed upon in the 2021 ERP. The Joint Petitioners oppose the operational limitation, arguing that it is premature and that further evaluation is necessary before the Commission imposes such limits.

78. We agree with arguments from intervenors that the various settlements contemplating the closure of Unit 2 and the operational restrictions on Unit 3 should be respected.⁵⁶ Public Service never suggested in the CEP Delivery Plan or the JTS that the Company would need to surpass the 60 percent annual capacity factor limit on Unit 3 in order to maintain resource adequacy. Nor has the Company set forth sufficient evidence in this Proceeding to justify this result. Given that Unit 2 and Unit 3 are now intended to work together to do the work that Unit 3 would have done but for its closure, it is reasonable to apply Unit 3's operational limit from the 2021 ERP to both units. Finally, the Joint Petitioners' argument to wait until the Step 2 application filing in June 2026 is unhelpful. Even with a 120-day expedited schedule, the Commission would not issue a decision on the Step 2 application filing until October, and RRR could push a final decision into late November. This would leave approximately one month in 2026 to implement operational limitations on Unit 2 and Unit 3.

⁵⁶ Chair Blank dissents from this point and would require additional reporting on the collective operation of Unit 2 and Unit 3 but would not impose the operational limitation. Chair Blank expresses concerns about non-economic dispatch and how much the operational limitation would cost.

79. We therefore approve the 3,942,000 MWh operational restriction at Unit 2 and Unit 3 as proposed in the Alternate Plan. If Public Service has concerns with the 3,942,000 MWh limitation, the Company may file an appropriate request supported by testimony and other evidence. This pathway maintains the emissions status quo the parties agreed upon in the respective settlements while appropriately putting the burden on the Company to explain why exceeding the agreed upon limit is in the public interest.

5. CEC's Resource Planning Recommendations

80. As set forth above, CEC recommends the Commission impose certain resource planning conditions, warning of a situation in which Public Service can simultaneously earn a return of and on its investment in Unit 2's extended operation, the resources acquired to replace Unit 2, and Unit 3 (once operational).⁵⁷

81. We decline to adopt CEC's resource planning conditions. The resources selected in the 2021 ERP/CEP and that will be selected in the JTS will serve Public Service's system for 10 years or more. While the extension of Unit 2 changes the Company's loads and resources table in the short term, it is unlikely to have a significant impact on long-term resources acquired in these proceedings, especially if the Company remains in a capacity short position. Unit 2 running together with Unit 3 would have a more significant impact, especially if both are kept operating past 2026. At this point, however, the Commission and parties do not have sufficient information to assess the likelihood of this situation.

⁵⁷ CEC Response at p. 10.

II. ORDER

A. The Commission Orders That:

1. The Motion seeking to permissively intervene filed by the City of Boulder on November 20, 2025, is granted.

2. The Motion seeking to permissively intervene jointly filed by the Board of County Commissioners of Pueblo County, City of Pueblo, and Pueblo Economic Development Corporation, on November 20, 2025, is granted.

3. The Motion seeking to permissively intervene filed jointly by GreenLatinos, GRID Alternatives, Ebony Advocates, NAACP Pueblo Branch, Roots to Resilience, and Vote Solar on November 20 2025, is granted.

4. The Motion seeking to permissively intervene filed by Western Resource Advocates on November 20, 2025, is granted.

5. The Motion seeking to permissively intervene filed by Colorado Energy Consumers on November 20, 2025, is granted.

6. The Motion seeking to permissively intervene filed jointly by Sierra Club and Natural Resources Defense Council on November 20, 2025, is granted.

7. The Motion seeking to permissively intervene filed by the Colorado Renewable Energy Society on November 20, 2025, is granted.

8. The Motion seeking to permissively intervene filed by Climax Molybdenum Company on November 20, 2025, is granted.

9. The late-filed Motion seeking to permissively intervene filed by CORE Electric Cooperative on December 2, 2025, is granted.

10. The Joint Petition filed by Trial Staff of the Public Utilities Commission, Colorado Energy Office, the Colorado Office of the Utility Consumer Advocate, and Public Service Company of Colorado on November 10, 2025, is granted with modifications, consistent with the discussion above.

11. The 20-day period provided for in § 40-6-114, C.R.S., within which to file an Application for Rehearing, Reargument, or Reconsideration, begins on the first day following the effective date of this Decision.

12. This Decision is effective immediately upon its Issued Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING
December 3 and December 10, 2025.**

(S E A L)



ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK⁵⁸

MEGAN M. GILMAN

TOM PLANT

Commissioners

COMMISSIONER ERIC BLANK
DISSENTS, IN PART

⁵⁸Eric Blank dissents in part.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit BBB: Department, Order No. 202-26-20 (Mar. 23, 2026)



Department of Energy
Washington, DC 20585

Order No. 202-26-20

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 (U.S.) 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 F.B. Culley Generating Station (Culley) is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW.³ Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 was slated to cease operations in December 2025.⁴

Order No. 202-25-13, issued pursuant to FPA section 202(c), required that Culley Unit 2 remain in operation for 90 days, through March 23, 2026. This order was 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 faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.⁵ I determined that the continued operation of

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 a coal-fired facility, it would be difficult for Culley Unit 2 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 Culley were to begin disassembling Unit 2 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 See, e.g., *Midcontinent Indep. Sys. Operator, Inc., and Northern Indiana Public Service Company*, Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

Culley Unit 2 would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.⁶ I determined that the continued operation of Culley Unit 2 was necessary to alleviate immediate and anticipated threats to reliability.⁷

My determination was based on several facts.

First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, 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.”⁸ Additionally, the LTRA notes that “[t]he departure of MISO’s coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years.”⁹

Second, 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.¹⁰ MISO justified this revision by explaining that “Reliability risks associated with [r]esource [a]dequacy have shifted from ‘Summer only’ to a year-round concern.”¹¹ 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.¹²

⁶ See, e.g., *id.* at 1–4.

⁷ See, e.g., *id.* at 5.

⁸ NERC, *2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

⁹ *Id.* at 44.

¹⁰ *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).

¹¹ *MISO Transmittal Letter*, FERC Docket No. ER22-495-000, at 3 (Nov. 30, 2021).

¹² *Id.* at 3–4.

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-25-13 continue, both in the near and long term.¹³ The production of electricity from Culley Unit 2 will continue to be critical to maintain reliability in MISO. MISO’s resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Culley operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 “MaxGen” event for MISO’s North and Central Regions due to generation outages, high demand, and transfer capability limits.¹⁴ From January 21–February 1, 2026, Culley operated at roughly 30 MW almost every day, providing vital generation capacity to the region.¹⁵

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.”¹⁶ Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects risk of loss of load in the winter and spring seasons; although not as high as in the summer or fall, losses will nevertheless increase over time.¹⁷

¹³ Further, as noted in Order No. 202-25-13, as a coal-fired facility, it would be difficult for Culley Unit 2 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. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If CenterPoint Energy were to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required so long as I determine a shortage exists. *See* Order No. 202-25-13 at 1.

¹⁴ *See* Midcontinent ISO on X, (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

¹⁵ U.S. Dep’t of Energy, *FACT SHEET: Energy Department Prevented Blackouts & Saved American Lives During Winter Storms*, (February 2026), <https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms>.

¹⁶ MISO, *Attributes Roadmap*, at 3 (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>.

¹⁷ *Id.* at 11.

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*.”¹⁸ 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.¹⁹ These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.²⁰ NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,²¹ stating that it faces significant reliability challenges as “projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements.”²² This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.²³ The 2025 NERC Long-Term Reliability Assessment notes that “MISO’s accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements.”²⁴ The report observes that winter peak periods are a particular concern, with projections showing “shortfalls in planned resources for winter peak periods.”²⁵ However, NERC also concluded that “risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high.”²⁶

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the “[p]otential for insufficient operating reserves

¹⁸ MISO, *MISO’s Response to the Reliability Imperative* (Updated February 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final+504018.pdf>.

¹⁹ *Id.* at 12.

²⁰ NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

²¹ *Id.* at 7.

²² *Id.* at 8.

²³ *Id.* at 43.

²⁴ *Id.* at 15.

²⁵ *Id.*

²⁶ *Id.*

in above-normal conditions.”²⁷ These findings were echoed in NERC’s 2024–2025 Winter Reliability Assessment, which noted that “[g]enerating capacity is 10 GW lower (-6.8%) compared to that of the prior winter as generators have retired, withdrawn from MISO’s capacity market, or received lower winter accredited capacity.”²⁸

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 accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Indiana.²⁹

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey, which reports the degree to which expected capacity resources satisfy planning reserve margin requirements.³⁰ 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.³¹ 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 2030.³² 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.³³

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.³⁴

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

²⁷ NERC, *2023 – 2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

²⁸ NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

²⁹ MISO, *Planning Resource Auction: Results for Planning Year 2025–26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%20250529_Corrections694160.pdf.

³⁰ OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025) <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

³¹ *Id.* at 2.

³² *Id.* at 7.

³³ *Id.* at 9.

³⁴ *Id.* at 7, 9.

increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.³⁵

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with almost another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, including Culley.³⁶

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, 2025.³⁷ 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.³⁸ 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.³⁹ Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order No. 202-25-13 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and

³⁵ *Id.*

³⁶ See *Electricity*, Energy Information Administration, Indiana Analysis, <https://www.eia.gov/states/in/analysis>.

³⁷ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

³⁸ *Id.* P 84.

³⁹ 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>.

extraordinary threat to our Nation’s economy, national security, and foreign policy.”⁴⁰ 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.”⁴¹ 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.”⁴²

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.”⁴³ 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.

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.”⁴⁴

⁴⁰ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

⁴¹ *Id.*

⁴² Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

⁴³ U.S. Dep’t of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf>.

⁴⁴ *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcomm. on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), <https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/>

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.”⁴⁵ 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.”⁴⁶

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest.”⁴⁷ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Culley Unit 2 shall be made available for operation through June 21, 2026.

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

- A. From March 24, 2026, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this

files/evo-media-document/witness-testimony_asthana_eng_grid-operators_03.25.2025.pdf.

⁴⁵ *Id.* at 6.

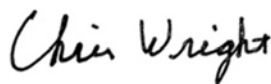
⁴⁶ *Id.* at 7.

⁴⁷ 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).

Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

- 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 Culley Unit 2 has operated in compliance with the allowances contained in this Order.
- C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.
- D. By April 8, 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 Culley Unit 2 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. CenterPoint Energy 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 Culley Unit 2 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, Culley Unit 2 shall not be considered a capacity resource.
- H. This Order shall be effective from March 24, 2026 through June 21, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of March 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

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

Indiana Utility Regulatory Commissioners

Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit C: Declaration of Erin O'Neil (Apr. 28, 2026)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

ORDER NO. 202-26-21

DECLARATION OF ERIN O'NEILL

I, Erin O'Neill, declare under penalty of perjury pursuant to 28 U.S.C. § 1746, that the following is true and correct to the best of my knowledge:

1. I am a resident of the State of Colorado. I am over the age of 18 and have personal knowledge of all the facts stated herein, except to those matters stated upon information and belief; as to those matters, I believe them to be true. If called as a witness, I could and would testify competently to the matters set forth below.

2. As Deputy Director of the Colorado Public Utilities Commission ("CoPUC"), I submit this declaration in support of the State of Colorado's Request for Rehearing ("Request") of the Department of Energy's ("Department") Order No. 202-26-21 ("Renewed Order") issued on March 30, 2026, regarding a coal-fired generating unit ("Craig Unit 1") at the Craig Station facility in Craig, Colorado.

Personal Background and Qualifications

3. I have served as the Deputy Director of the CoPUC since 2023.

4. I have a Bachelor of Science degree in Mechanical Engineering from Cornell University and a Master of Science in Technology and Policy from the Massachusetts Institute of Technology.

5. I have been employed in the Fixed Utilities Section of the CoPUC since 2016. My current position is Deputy Director where I am responsible for the management of the CoPUC's staff of litigation experts including professional engineers, economists, and accounting and financial experts. My duties also include providing technical economic and policy advice and testimony to the CoPUC. Prior to joining the CoPUC, I worked as an economic consultant in the energy and environmental industry for nearly 20 years. From 2005 through 2016 I worked as an independent consultant. From 1996 to 2005 I was a Senior Consultant for the NorthBridge Group, an economic and strategic consulting firm serving the electricity and gas industries. I have extensive experience in electricity price forecasting, resource planning, and risk management.

6. Under Article XXV of the Colorado State Constitution and Title 40 of the Colorado Revised Statutes ("Colo. Rev. Stat."), the CoPUC is the State regulatory agency with jurisdiction to regulate rates and charges for the sale of electric energy to consumers within the State, and to generally supervise and regulate public utilities in Colorado. This regulation includes the adjudication of Electric Resource Plans ("ERPs") filed by Colorado's investor-owned electric utilities and wholesale electric cooperatives.

7. As Deputy Director of Fixed Utilities, I routinely provide the CoPUC with expert witness testimony and direct the development and submission of expert witness testimony of the CoPUC's litigation staff. The CoPUC's staff provide testimony on electric resource planning covering topics, including load forecast, reserve margin requirements, effective load carrying capacity, reliability metrics, unit performance

characteristics, extreme weather and other sensitivity analyses, and transmission modeling. In addition to providing expert testimony on resource planning, I and my staff provide the CoPUC with expert witness testimony in applications for certificates of public convenience and necessity (“CPCNs”) for generation and transmission resources, distribution infrastructure planning, renewable energy portfolio standard plans, retail customer program offerings, and other proceedings.

Department of Energy Order

8. I am familiar with the Renewed Order regarding the Craig Unit 1 coal-fired power plant.

9. The Craig Station is a three-unit, 1,285 megawatt (“MW”) coal-fired electric generating facility located near Craig, Colorado. Craig Units 1 and 2 are owned by Tri-State Generation and Transmission Association, Inc. (“Tri-State”), Platte River Power Authority, PacifiCorp, Salt River Project, and Public Service Company of Colorado (“Public Service”) (collectively “Craig Unit 1 Owners”); Craig Unit 3 is 100% owned by Tri-State.¹ The nameplate capacity for Craig Unit 1 is 427 MW, for Craig Unit 2 is 410 MW, and for Craig Unit 3 is 448 MW.² Tri-State is the operating agent for all three units.³

10. “In 2016, Tri-State announced an agreement to retire Craig Unit 1 by December 31, 2025 as part of revisions to the Colorado [R]egional [H]aze State Implementation Plan [(“SIP”)].”⁴ In 2020, Tri-State announced its Responsible Energy

¹ Exhibit F (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-2 (Tri-State, 2020 IRP/ERP, Public (Dec. 1, 2020)) (“2020 ERP”)), at 182.

² See *id.*

³ See *id.*

⁴ See *id.*

Plan, which included the announced retirements of Craig Unit 2 by September 30, 2028, and Craig Unit 3 by December 31, 2030.⁵ More recently, the CoPUC approved a January 1, 2028 retirement date for Craig Unit 3.⁶ Craig Unit 1's approved retirement has been incorporated into extensive resource adequacy planning processes throughout the last decade.

11. This declaration addresses the CoPUC's resource planning process and recent CoPUC resource planning proceedings.

I. The CoPUC's Resource Planning Processes

12. For decades, Colorado has implemented robust and successful electric resource planning processes. These have been a model for the competitive acquisition of generating resources, assessing reliability and determining that there will be sufficient electricity to meet expected load, including planning for plant retirements. These processes consider resource adequacy and reliability, while ensuring that Colorado rates remain economic and balance a multitude of federal, State and local interests.⁷

13. As part of Colorado's overall energy planning framework, each investor-owned retail electric utility and wholesale electric generation and transmission cooperative is required to submit to the CoPUC an application for approval of an ERP.⁸

⁵ See *id.* at 23; Exhibit G (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1 (Tri-State, *Responsible Energy Plan* (Jan. 2020))), at 3.

⁶ Exhibit AA (CoPUC, Decision No. R24-0602, issued on August 22, 2024, in Proceeding No. 23A-0585E), ¶ 60.

⁷ FERC Order No. 872 supports the use of competitive solicitations as a means to foster competition in the procurement of generation and to encourage the development of Qualifying Facilities under the Public Utility Regulatory Policies Act of 1978. *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978* (Order No. 872), 172 F.E.R.C. ¶ 61,041, ¶ 416 (2020).

⁸ § 40-2-125.5, Colo. Rev. Stat.; 4 Colo. Code Regs. § 723-3-3603(a) (2025).

The utility must conduct a periodic examination of its energy sales and demand forecasts as compared to its existing resources to ensure that sufficient generation will be available to meet customer needs, ensure reliability, and satisfy any applicable emission reduction requirements. ERPs must contain electric demand and energy forecasts, evaluation of existing resources, an assessment of planning reserve margins and contingency plans for the acquisition of additional resources. Each ERP proceeding thoroughly considers resource adequacy and reliability at multiple stages.

14. Through Colorado’s resource planning process, utilities thoroughly consider and review inputs to resource adequacy analyses to arrive at a target planning reserve margin. Colorado’s regulated electric utilities have historically planned for a 0.1 days per year loss of load expectation (“LOLE”) standard, meaning that the system should be expected to have insufficient resources to serve load on no more than one day every 10 years.⁹ Using this LOLE and the resulting planning reserve margin required to maintain this LOLE, the utilities propose additional generation amounts for the planning period. Following extensive stakeholder input and vetting through cross examination and consideration by the CoPUC, the utilities conduct a competitive all-source solicitation for these additional resources. The additional generation must be able to cost-effectively meet system needs, including availability or dispatchability at certain hours of the day.

⁹ See CoPUC, Hrg. Ex. 109, Direct Testimony and Attachments of Zachary Ming, Rev. 1, filed on May 30, 2025, in Proceeding No. 24A-0422E; CoPUC, Hrg. Ex. 109, Direct Testimony and Attachments of Zachary Ming, Rev. 1, ZM-1(Energy Environmental Economics, *2024 Public Service Company of Colorado Resource Adequacy Study* (Aug. 2024)), filed on May 30, 2025, in Proceeding No. 24A-0422E; CoPUC, Hrg. Ex. 115, Direct Testimony and Attachments of Kevin D. Carden, filed on March 31, 2025, in Proceeding No. 21A-0141E, at 8-10.

15. In each ERP, the utility must identify a resource acquisition period, provide the forecast loads and resources balance through that period, and provide forecasting, modeling, and analytical data to support the proposed acquisition period and level of resource acquisition. The resource acquisition period is proposed by the utility and approved by the Commission to address periods of anticipated capacity shortfall with sufficient lead time to procure or build cost-effective projects to address the identified need. When the utility industry has undergone large transitions or has faced a geopolitical or regulatory climate that injects significant uncertainty into resource planning, the CoPUC has approved ERPs with shorter resource acquisition periods that still allow for the lead-time needed to build resources. In such situations, relying on shorter and medium-term forecasts and modeling can provide more certainty that Colorado customers will not pay for unnecessary generation acquired in response to inaccurate load projections produced by speculative long-term modeling.

16. In addition, Colorado's resource planning process allows for the filing of interim ERPs to fill generation needs not identified or fully satisfied by ERPs completed on the regular cadence, including in case of project failures of selected ERP resources.¹⁰ And outside of the ERP processes, the CoPUC may approve the construction of generating resources by granting CPCNs for specific resources proposed by the utility.¹¹ The Colorado public utility statutes and the CoPUC's procedural rules also allow for the modification of prior CoPUC decisions, and waiver

¹⁰ 4 Colo. Code Regs. §§ 723-3-3603(a), -3605(a)(II) (2025).

¹¹ 4 Colo. Code Regs. § 723-3-3102 (2025).

or variance requests.¹² These interim ERP processes, CPCN proceedings, and procedural options allow electric utilities and the State to quickly respond to changes in load or available resources.

17. The Colorado resource planning process addresses medium and long-term resource needs through a careful, robust, and competitive process to ensure cost effective system reliability. And the process allows utilities to flexibly respond to new situations through mechanisms such as interim resource plans, CPCNs, and the designation of back-up projects in case of project failures. The CoPUC has significant experience with the energy planning of Colorado’s utilities and with Colorado’s energy policies. The CoPUC also has access to a range of data, insights, and assessments regarding the needs and capabilities of Colorado’s electric grid. To my knowledge, the Department did not attempt to consult with the CoPUC regarding any aspect of the Renewed Order.

II. Tri-State’s Colorado Resource Planning Requirements

18. The CoPUC has examined Tri-State’s resource planning for over a decade.¹³ For many years, Tri-State submitted resource planning reports to the CoPUC. In 2019, the Colorado General Assembly required the CoPUC to promulgate new ERP rules addressing applications for approval of ERPs filed by Tri-State, Colorado’s single wholesale electric cooperative.¹⁴ These rules were adopted by the CoPUC in March 2020.¹⁵

¹² § 40-6-112, Colo. Rev. Stat.; 4 Colo. Code Regs. § 723-1-1003 (2025).

¹³ See CoPUC, Decision No. C11-0721, issued on July 5, 2011, in Proceeding No. 10M-879E.

¹⁴ § 40-2-134, Colo. Rev. Stat.

¹⁵ CoPUC, Decision No. C20-0155, issued on March 10, 2020, in Proceeding No. 19R-0408E.

19. Under the CoPUC’s ERP rules, Tri-State was required to file an ERP in 2020, and it must file an ERP every four years beginning June 1, 2023.¹⁶ In addition to the required four-year cycle, Tri-State may file interim plans or requests for CPCNs.¹⁷

20. Colorado ERP proceedings contain two phases. In Phase I, the CoPUC reviews and may approve, or approve with modifications, the utility’s plan to acquire new utility resources. In Phase I of the ERP process, the CoPUC assesses the energy and capacity needs of the utility, determines an indicative resource acquisition plan based on generic pricing and characteristics for available generation types, and establishes the analytical evaluation framework for ultimate project selection. Following Phase I, the utility conducts a competitive, all-source solicitation and receives bids for resources. Using these bids and resource planning modeling software, the utility prepares portfolios of resources that differ based on modeling inputs and assumptions, which fulfill different economic and policy goals such as least cost, high labor scoring, geographic diversity of resources, deeper emissions reductions, and balanced utility and developer ownership. In Phase II, a final cost-effective resource portfolio is determined. Phase II ERP modeling may also include the evaluation of significant market uncertainties, most often load growth and natural gas prices.

21. Tri-State initiates Phase I of an ERP proceeding by filing its ERP application. Among many other required components, each ERP application must include: a proposed resource acquisition period; an annual electric demand and

¹⁶ 4 Colo. Code Regs. §§ 723-3-3605(a)(I), -(II) (2025).

¹⁷ 4 Colo. Code Regs. §§ 723-3-3102, -3605(a)(II) (2025).

energy forecast; assessments of existing generation and transmission resources; an assessment of planning reserve margins; an assessment of the need for additional resources based on the forecasts, existing resources, planning reserve margins, estimation of the effective load carrying capacity by resource type, and other factors; a proposed Request for Proposal and model contracts to be used to solicit resource bids, and bid evaluation criteria Tri-State will use in ranking bids received.¹⁸

22. Electric energy and demand forecasts must be completed for each year within the planning period, and must be fully explained and documented with data, assumptions, methodologies, and models.¹⁹ The forecasts must include, among other components, the electric demand placed on the utility's system for each hour of the day for peak-day, average-day, and representative off-peak days for each calendar month.²⁰ Tri-State must develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period, including base case, high, and low forecast scenarios.²¹

23. Each ERP application must justify planning reserve margins for the base case, high, and low forecast scenarios, to include risks associated with the development of generation, losses of generation capacity, losses of transmission capability, risks due to known or reasonably expected changes in environmental

¹⁸ 4 Colo. Code Regs. §§ 723-3-3605(a)(IV), -(f), -(g)(II)(G)(ii) (2025).

¹⁹ 4 Colo. Code Regs. § 723-3-3605(b) (2025).

²⁰ *Id.*

²¹ *Id.*

regulatory requirements, and other risks.²² Tri-State must also describe and justify the means by which it assesses system reliability.²³

24. The application must also include an assessment of the costs and benefits of early retirements of utility-owned resources, an assessment of the costs and benefits of the integration of intermittent resources on the utility's system, and contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs or the acquisition of replacement resources if expected resources are not developed in accordance with the approved ERP.²⁴

25. After an adjudication on the ERP application, involving discovery, rounds of written testimony and associated documents resulting in records with page counts totaling in the tens of thousands or hundreds of thousands, robust stakeholder engagement, public comment hearings, a live evidentiary hearing with cross-examination by parties and the CoPUC, negotiated settlements and stipulations, and any necessary briefing, the CoPUC must issue a Phase I decision. This includes determinations on the need for additional resources, planning reserve margin, methodology for determining resource effective load carrying capacity by resources type and geography, the documents and analytical methodology to be used in a competitive resource solicitation, and bid evaluation criteria. The Phase I decision also defines the specific alternative portfolios Tri-State must model in Phase II after bids are received,²⁵ for example a least-cost portfolio or a reduced load portfolio and

²² 4 Colo. Code Regs. § 723-3-3605(e) (2025).

²³ *Id.*

²⁴ 4 Colo. Code Regs. §§ 723-3-3605(a), -(e)(III) (2025).

²⁵ 4 Colo. Code Regs. § 723-3-3605(g)(III)(B) (2025).

the sensitivity analyses to be conducted (e.g., high load growth or high natural gas prices).

26. Phase II of the ERP proceeding begins after the issuance of the Phase I decision. Tri-State will conduct its competitive, all-source solicitation, receive competitive bids and utility-owned proposals, and file an ERP Implementation Report. In the ERP Implementation Report, Tri-State must present the resource portfolios required by the Phase I decision, with associated cost and other information, and must identify its preferred, cost-effective resource plan (*i.e.*, its preferred resource portfolio).²⁶

27. After an opportunity for party comments on the ERP Implementation Report, an opportunity for Tri-State to respond to such comments, and any other necessary procedures, the CoPUC issues its Phase II decision establishing the final cost-effective resource plan.²⁷ In making this decision the CoPUC considers various statutory factors, including whether the resource plan meets the energy policy goals of Colorado, such as giving full consideration to cost-effective resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.²⁸

28. Following the Phase II decision, Tri-State then proceeds to implement the approved resource portfolio. Additionally, Tri-State must file annual progress reports with the CoPUC on its efforts under the approved plan and on emerging resource needs, including an updated forecast, an updated evaluation of planning

²⁶ 4 Colo. Code Regs. § 723-3-3605(h) (2025).

²⁷ *Id.*

²⁸ *Id.*; § 40-2-134, Colo. Rev. Stat.

reserve margins and contingency plans, and an updated assessment of additional resource needs.²⁹

III. Relevant CoPUC Resource Planning Proceedings

29. Since the announcement in 2016 that Craig Unit 1 would retire by December 31, 2025, the CoPUC has considered multiple electric resource planning reports and ERPs that include the unit's retirement as an assumption in the modeling of resource needs. None of these proceedings resulted in a CoPUC determination that the retirement of Craig Unit 1 would result in reliability issues.³⁰

30. Tri-State's 2015 Integrated Resource Plan ("IRP")/ERP was filed on October 30, 2015 in accordance with CoPUC rules requiring reports on resource planning.³¹ While this pre-dates the Craig Unit 1 retirement announcement in 2016, Tri-State's 2015 IRP/ERP addresses resource planning methods that remained relevant until Tri-State's subsequent 2020 ERP application filing.

31. In its 2015 IRP/ERP, Tri-State presented its planning for the resource acquisition period 2016-2021, and a planning period 2016-2035. Tri-State reported that under the base load scenario with full planning reserves, it did not expect a capacity shortage within the resource acquisition period, and that it projected it

²⁹ 4 Colo. Code Regs. § 723-3-3618 (2025).

³⁰ See CoPUC, Decision No. R22-0191, issued on March 28, 2022, in Proceeding No. 20A-0528E; CoPUC, Decision No. C23-0437, issued on June 30, 2023, in Proceeding No. 20A-0528E; Exhibit AA; Exhibit E (CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E); CoPUC, Decision No. C22-0459, issued August 3, 2022, in Proceeding No. 21A-0141E; CoPUC, Decision No. C24-0052, issued on January 23, 2024, in Proceeding No. 21A-0141E; CoPUC, Decision No. C25-0747, issued on November 6, 2025, in Proceeding No. 24A-0442E.

³¹ CoPUC, Tri-State, IRP/ERP ("Tri-State 2015 IRP/ERP"), filed on October 30, 2015, in Proceeding No. 15M-0852E. Tri-State explained its 2015 IRP/ERP was developed to meet the Integrated Resource Planning requirements of the Western Area Power Administration and the ERP requirements of the CoPUC. Tri-State 2015 IRP/ERP, at 5.

would not need additional generation resources until 2023.³² As part of its support for this statement, Tri-State presented an assessment of planning reserve margins. It explained that, at the time, it used a fixed 15% minimum planning reserve margin and that this 15% level had been the industry standard for years.³³

32. Tri-State's 2015 IRP/ERP also catalogued its various methods for responding to unexpected capacity shortages, including employing small diesel generation and relying on its membership in utility reserve sharing groups or reciprocal outage assistance arrangements with other utilities.³⁴ For any longer-term resource adequacy shortcomings, Tri-State explained that it reevaluates its future load/resource balance at a minimum one-year interval to identify and appropriately resolve resource adequacy issues.³⁵ It explained it would be well positioned to respond to longer-term contingencies through pursuing additional demand-side resources, power purchase agreements, or capacity self-build.³⁶

33. Tri-State first incorporated the retirement of Craig Unit 1 by December 31, 2025 in the scenario modeling for its 2017 Annual Progress Report.³⁷ After updating its resource planning model inputs to include changes to its generation portfolio, including the retirement of Craig Unit 1, Tri-State reported that new

³² See *id.* at 107, 132.

³³ See *id.* at 107.

³⁴ See *id.* at 108.

³⁵ See *id.*

³⁶ See *id.* at 107-108.

³⁷ CoPUC, ERP Annual Progress Report, Revised, filed on June 2, 2017, in Proceeding No. 15M-0852E.

generating capacity would not be needed until 2025.³⁸ Subsequent annual progress reports moved this date to 2026 and then 2027.³⁹

34. Tri-State’s 2020 ERP application, which was subject to CoPUC review and approval under new statutory provisions, was intended “to describe Tri-State’s need for additional electric resources, and ultimately identify a cost-effective resource portfolio to reliably meet such need[,]” and “to respond to what Tri-State’s Utility Members and their member-customers have been asking for - a transition to a cleaner power supply, reduced GHG emissions, and an opportunity to realize the potential benefits of lower cost electricity.”⁴⁰ Tri-State also emphasized that its resource planning process “is intended to generate a plan to meet forecast energy and demand obligations with existing resources, new resources, and/or market purchases, while respecting environmental and transmission constraints, complying with applicable federal and State legislative and regulatory obligations, and doing so in the most economical and reliable manner.”⁴¹

35. Tri-State presented a 10-year resource acquisition period (2021-2030) and a 20-year resource planning period (2021-2040). In its assessment of resource needs, Tri-State assumed the retirement of Craig Unit 1 by December 31, 2025, the retirement of Craig Unit 2 by September 30, 2028, and Craig Unit 3 by December 31,

³⁸ *See id.* at 16.

³⁹ CoPUC, ERP for Annual Progress Report, filed on October 31, 2018, in Proceeding No. 15M-0852E, at 17; CoPUC, ERP Annual Progress Report, filed on December 10, 2019, in Proceeding No. 15M-0852E, at 22.

⁴⁰ Exhibit JJ (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E), at 35:1-15.

⁴¹ CoPUC, Hrg. Ex. 102, Direct Testimony and Attachments of Lisa K. Tiffin, filed on December 1, 2020, in Proceeding No. 20A-0528E, at 7:15-20.

2029.⁴² Tri-State identified a need for new generation in 2029 to provide replacement capacity support for the announced retirement of Craig Unit 3, but did not identify any other resource needs given its expected generation portfolio and load forecast.⁴³

36. To identify its need for additional resources, Tri-State developed a range of long-term load forecasts, including base case, low load, and high load scenarios.⁴⁴ Tri-State used a 15% planning reserve margin, and supported the adequacy of the planning reserve margin and the viability of expansion plans under different load scenarios using a probabilistic Loss of Load Probability (“LOLP”) study.⁴⁵ The study used the target “LOLP of less than [one] day in 10 years[,] which corresponds to a LOLP of less than 0.0274 percent on an annual hour basis.”⁴⁶ The study analyzed “two forecast years, 2025 and 2030, under four capacity expansion [(“CE”)] plans” using varying load forecasts and capacity addition assumptions.⁴⁷ For two of these CE scenarios, the study found the target would be exceeded in 2030, while the other plans met the target in both years.⁴⁸ The study found that additional energy storage capability would be able to compensate for these exceedances so that all scenarios met the LOLP target.⁴⁹ Tri-State explained that its ERP scenarios followed this methodology and included standalone batteries as selected by the models in the base case and alternative scenarios evaluated in its ERP, including in its

⁴² Exhibit F, at 31.

⁴³ Exhibit JJ, at 37:15-19.

⁴⁴ CoPUC, Hrg. Ex. 102, Direct Testimony and Attachments of Lisa K. Tiffin, filed on December 1, 2020, in Proceeding No. 20A-0528E, at 21:1-11.

⁴⁵ See *id.* at 41:10-42:7; Exhibit F, at 2348-2356.

⁴⁶ See *id.* at 2355.

⁴⁷ See *id.* at 2351.

⁴⁸ See *id.* at 2351.

⁴⁹ See *id.* at 2351 (finding the addition of “two (2) and three (3) 100 MW 4-hour batteries with 400 MWh of energy storage capability. . . . to the Base CE and MARS CE plans, respectively[,]” resulted in both plans meeting the LOLP target).

preferred plan.⁵⁰ Tri-State also explained that “[a]ll scenarios to some extent utilize transmission interconnection capacity made available by thermal retirements. All plans show considerable resource additions in [western Colorado] due to the transmission capacity that will become available through the retirement of the Craig facility.”⁵¹

37. Tri-State also addressed its contingency plans for how electric generation and customer demand will actually show up during the resource acquisition period, explaining it has various options including purchasing short-term capacity through resource solicitations, initiation of negotiations with replacement bidder(s), and acceleration of project in-service dates.⁵²

38. After modelling an additional six variations of its initial preferred plan through a stakeholder process and at the direction of the CoPUC, with each variation assuming the retirement of Craig Unit 1 by December 31, 2025, Tri-State arrived at its Revised Preferred Plan.⁵³ “[T]he Revised Preferred Plan would add approximately 2 GW of new renewable generation and 250 MW of new battery storage by 2030,” and a new gas-fired resource in 2030, alongside the retirement of certain coal units by 2030.⁵⁴ Tri-State explained the Revised Preferred Plan was “the responsible and economic resource plan because it reflects the known financial, operational, and

⁵⁰ See *id.* at 30.

⁵¹ See *id.* at 135.

⁵² See *id.* at 30.

⁵³ CoPUC, Hrg. Ex. 109, Second Supplemental Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 2, filed on September 28, 2021, in Proceeding No. 20A-0528E, Fourth Corrected Attachment LKT-3 (Tri-State, 2020 IRP/ERP (Sept. 28, 2021, filed on Nov. 10, 2021)), at 99.

⁵⁴ CoPUC, Hrg. Ex. 109, Second Supplemental Direct Testimony and Attachments of Lisa K. Tiffin, filed on September 28, 2021, in Proceeding No. 20A-0528E, at 12:15-13:16.

contractual conditions of our system, while maintaining a focus on reliability and affordability for our Members.”⁵⁵

39. In its Phase I decision, the CoPUC approved Tri-State’s 2020 ERP application and specifically the modelling inputs and assumptions in Tri-State’s Revised Preferred Plan with limited modifications contained in a settlement agreement.⁵⁶ The CoPUC also directed that after Tri-State receives resource bids, it models at least four Phase II resource portfolios in addition to the base Revised Preferred Plan, each with a sensitivity for extreme weather and high gas price.⁵⁷

40. In its 2020 ERP Phase II Implementation Report, Tri-State reported on the results of its competitive resource solicitation and presented five resource portfolios. In its comparative portfolio analysis, Tri-State explained that it performed a reliability metric check on each portfolio, including that the portfolio would meet: a planning reserve margin minimum of 15%, the loss of load hours target of less than one day in 10 years, and an expected unserved energy target of less than 0.5 Gigawatt hours (“GWh”) annually.⁵⁸

41. Tri-State’s Phase II preferred cost-effective resource portfolio continued to be the Revised Preferred Plan portfolio, which it selected as a result of the portfolio’s “overall performance across the reliability, environmental, and financial categories analyzed” and which it supported as reflective of “its Members’ strategic directives to ensure reliable, affordable, and responsible service.”⁵⁹ It

⁵⁵ See *id.* at 13:1-9.

⁵⁶ CoPUC, Decision No. R22-0191, issued on March 28, 2022, in Proceeding No. 20A-0528E.

⁵⁷ *Id.*, ¶¶ 49-50.

⁵⁸ CoPUC, 150-Day Report, Public, filed on February 13, 2023, in Proceeding No. 20A-0528E, at 17.

⁵⁹ See *id.* at 5.

explained that the portfolio resulted in planning reserve margins ranging from 17% in 2022 to 29% in 2030, with zero loss of load hours and zero annual expected unserved energy during that period.⁶⁰ Tri-State also explained that in the period from 2025-2029 when Craig Units 1 and 2 retire, “it continues to be capacity-long and maintains a sufficient mix of both dispatchable and intermittent resources to meet load needs.”⁶¹ In its Phase II decision, the CoPUC approved Tri-State’s selection of the Revised Preferred Plan portfolio as the cost-effective resource plan.⁶² Tri-State later confirmed that it “is capacity-long and the 2026 resources identified in the 2020 ERP Phase II are not necessary for meeting resource adequacy or reliability requirements.”⁶³

42. Tri-State’s next ERP was filed in 2023. Tri-State explained that through its 2023 ERP, “Tri-State will ensure reliability and resource adequacy, maintain affordability for Members, and meet compliance obligations, including those related to environmental responsibility.”⁶⁴ Tri-State presented a 6-year resource acquisition period (2026-2031) and a 20-year resource planning period (2024-2043). In its assessment of resource needs, Tri-State assumed the retirement of Craig Unit 1 by December 31, 2025, the retirement of Craig Unit 2 by September 30, 2028, and Craig Unit 3 by January 1, 2028.⁶⁵ Tri-State explained it “selected an acquisition period of

⁶⁰ See *id.* at 28.

⁶¹ See *id.*

⁶² CoPUC, Decision No. C23-0437, issued on June 30, 2023, in Proceeding No. 20A-0528E, ¶ 47.

⁶³ CoPUC, Notice of Failed Bids, Public, filed on July 24, 2023, in Proceeding No. 20A-0528E, ¶ 12.

⁶⁴ 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), at 11:22-12:4.

⁶⁵ 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))), at 19, 21, 32, 44, 55, 66.

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.”⁶⁶

43. To identify its need for additional resources, Tri-State developed a range of long-term load forecasts, including base case, low load, and high load scenarios.⁶⁷ Tri-State increased its planning reserve margin to 22%, transitioning to a 30.5% reserve margin in 2028 after the retirement of Craig Station. This approach “was developed through a Strategic Energy Risk Valuation Model [(“SERVM”), which Tri-State described as] 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[,] . . . able to identify potential risks to system reliability across the entire year, not just at system peak.”⁶⁸ As part of this modeling, Effective Load Carrying Capabilities (“ELCCs”) were determined for each resource type to model each resource’s capacity potential for the specifics of Tri-State’s system, rather than simply relying on the nameplate capacity adjusted for the availability factor.⁶⁹ Such ELCC calculations incorporate the coincidence of resource generation with system peak demand accounting for specific geographic location and the proximity of other existing renewable resources. The model used the target LOLE of 0.1 days/year, which is equivalent to an expectation of one day of loss

⁶⁶ See *id.* at 6.

⁶⁷ Exhibit CC (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-Attachment F (*Electric Energy and Demand Forecast*, Public)), at 7-9.

⁶⁸ Exhibit X, at 14.

⁶⁹ Exhibit OO (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 - Attachment G-1 (*Astrape Consulting, Reserve Margin and Effective Load Carrying Capability (ELCC) Study*, Public (Aug. 2, 2023))), at 8.

of load every 10 years.⁷⁰ The use of ELCC calculations is a conservative view of accredited capacity because it takes into account the intermittency of each resource type, the specific geographic location of each resource, and the proximity of other resources of a like type and corresponding reduction in dependable capacity such proximity creates. Tri-State explained that the planning reserve margin calculation also “discounts the capacity of conventional resources by their Equivalent Forced Outage Rate and several of Tri-State’s thermal resources have relatively high and increasing forced outage rates.”⁷¹

44. Tri-State modeled five scenarios for Phase I of its 2023 ERP, and for each scenario, sensitivity analyses were performed on each scenario’s expansion plan to re-dispatch the plans under extreme weather events and high gas price conditions.⁷² “Level 1” reliability metric checks were performed on each scenario to ensure it would meet: a planning reserve margin minimum of 22%, transitioning to 30.5% in 2028, the loss of load hours target of less than one day in 10 years, and an expected unserved energy target of less than 0.4 GWh annually.⁷³ Additional “Level 2” reliability checks were performed on each scenario’s extreme weather event sensitivity result.⁷⁴ Tri-State explained that each scenario was able to meet the Level 1 and Level 2 reliability metrics during the resource acquisition period.⁷⁵

⁷⁰ See *id.* at 8.

⁷¹ Exhibit DD (CoPUC, Hrg. Ex. 103, Direct Testimony and Attachments of Brian L. Thompson, Rev. 1, filed on May 24, 2024, in Proceeding No. 23A-0585E), at 15:2-4.

⁷² Exhibit X, at 15.

⁷³ See *id.* at 17.

⁷⁴ See *id.* at 18.

⁷⁵ See *id.* at 90.

45. In its Phase I decision on Tri-State’s 2023 ERP, the CoPUC approved Tri-State’s 2023 ERP application, including Tri-State’s evaluation of need during the resource acquisition period and the retirement date of January 1, 2028 for Craig Unit 3.⁷⁶ The CoPUC also directed that after Tri-State receives resource bids, it modeled various portfolios including Tri-State’s preferred scenario, each with a sensitivity for extreme weather.⁷⁷

46. In its 2023 ERP Phase II Implementation Report, Tri-State reported on the results of its competitive resource solicitation and presented six resource portfolios.⁷⁸ The analysis of each portfolio includes in its assumptions the retirement of Craig Unit 1 by December 31, 2025, Craig Unit 2 by September 30, 2028, and Craig Unit 3 by January 1, 2028.⁷⁹ Tri-State also created three back-up bid pools.⁸⁰

47. Tri-State’s Phase II preferred cost-effective resource portfolio was the New ERA Gas Flexibility Shafer Replacement (“FLEXSR”) portfolio, which it selected as a result of the portfolio’s “overall performance across the reliability, environmental, and financial categories analyzed” and which it supported as reflective of “its Members’ strategic directives to ensure reliable, affordable, and responsible service.”⁸¹ The FLEXSR portfolio, “which was the least-cost portfolio, would add 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031[;]” replace turbines at an existing gas-powered combined cycle generating facility; and

⁷⁶ Exhibit AA, ¶¶ 50, 60.

⁷⁷ See *id.* ¶¶ 29, 50.

⁷⁸ Exhibit J (CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E).

⁷⁹ See *id.* at 21, 32, 43, 54, 64, and 75.

⁸⁰ See *id.* at 7.

⁸¹ See *id.* at 6.

retire two coal plants within the resource acquisition period.⁸² This portfolio also assumes the previously announced retirement dates of Craig Unit 1 and Craig Unit 2 and the newly approved retirement of Craig Unit 3 by January 1, 2028.⁸³ The 307 MW gas facility will interconnect at the Craig transmission substation and has a commercial operation date of 2029.

48. Tri-State explained that it performed a reliability metric check on each portfolio using the same Level 1 and Level 2 reliability metrics applied to Phase I scenarios, and that each portfolio satisfied the metrics.⁸⁴ It explained that the FLEXSR portfolio resulted in planning reserve margins ranging from 24% in 2025 to 34% in 2031, with zero loss of load hours and zero annual expected unserved energy during that period.⁸⁵ Tri-State explained that it remains in a capacity-long position until 2030, but that resource acquisitions are required during the 2023 ERP resource acquisition period to ensure new resources are available in 2030.⁸⁶

49. In its Phase II decision, the CoPUC approved Tri-State's selection of the FLEXSR portfolio as the cost-effective resource plan.⁸⁷ The CoPUC also found "Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP. Every portfolio that Tri-State modeled assumes Craig Unit 1 retires at the end of 2025 and does not provide any energy or capacity after 2025. At the

⁸² *See id.*

⁸³ *See id.* at 54.

⁸⁴ *See id.* at 95.

⁸⁵ *See id.* at 62.

⁸⁶ *See id.* at 7.

⁸⁷ Exhibit E, ¶ 90.

same time, Tri-State convincingly concludes that every portfolio meets all reliability metrics and is reliable.”⁸⁸

50. On December 1, 2025, Tri-State filed its annual ERP progress report. It reports that it “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 portfolio resources, including evaluation of back-up bids as needed.”⁸⁹ Tri-State stated that with an updated load forecast, utilized in Phase II of the 2023 ERP and Phase II preferred resources, it does not forecast a capacity shortfall to occur until 2035.⁹⁰

51. On March 17, 2026, Tri-State provided a further update on its ERP resource acquisitions. It reported it has executed contracts for 200 MW of wind generation, 100 MW of solar generation, and 550 MW of battery storage.⁹¹ Tri-State reports it is delaying pursuit of back-ups for certain bids, including a bid for 307 MW of gas-fired generation, until it attains further certainty regarding federal funding through the United States Department of Agriculture’s Empowering Rural America program.⁹²

⁸⁸ *See id.* ¶ 116.

⁸⁹ Exhibit Z (CoPUC, Tri-State, *2025 Annual Progress Report*, filed on December 1, 2025, in Proceeding No. 23A-0585E), at 10-11.

⁹⁰ *See id.* at 8.

⁹¹ Exhibit EEE (CoPUC, Tri-State, *Notice Regarding Phase II Developments*, filed on March 17, 2026, in Proceeding No. 23A-0585E), at 2.

⁹² *Id.* at 3.

52. Additionally, in its 2026 Electric Resource Adequacy Report, filed on March 17, 2026, Tri-State provided its expected loads and resources for years 2026 through 2035.⁹³ Tri-State shows that it expects excess resources for all years.⁹⁴

Conclusion

53. The CoPUC has been implementing careful and robust electric resource planning for decades. Colorado's process has developed over time to incorporate a competitive all-source solicitation to ensure cost-effective electricity supply. Colorado's quantitative modeling requirements allow different kinds of resources to be considered together to develop the energy supply system in a holistic manner. Colorado does not pre-maturely pick a winning technology or bid but rather allows the marketplace to develop and offer bids that can work within the system to reliably deliver cost-effective power.

54. The CoPUC's process incorporates a conservative approach to reliability by utilizing stringent loss of load metrics and incorporating and re-evaluating the system reserve margin as needed over time and depending on the resource mix of the system. Reliability is further considered through the robust calculation of ELCCs that incorporate geographic location and the potential saturation of other nearby renewable resources so that the ERP modeling accurately incorporates a portfolio view of accredited reliable capacity. In addition, Colorado considers and evaluates multiple future perspectives by modeling sensitivities such as extreme weather, high load growth, and high natural gas prices. This additional quantitative modeling serves

⁹³ Exhibit VV (CoPUC, Tri-State, Notice of 2026 Resource Adequacy Annual Report, filed on March 17, 2026, in Proceeding No. 26M-0028E).

⁹⁴ *Id.* at 3.

to stress test planning portfolio results to ensure reliable service. Colorado has a long history of robust resource planning, successfully partnering with utilities and a diverse set of stakeholders to develop cost-effective and reliable electric supply.

55. By delaying the retirement of this aging coal-fired unit, the Department is conflating dispatchability with reliability and undermining a decade of careful and collaborative planning. The end result is Colorado electric customers being forced to support an unreliable resource and the Craig Unit 1 Owners dedicating resources to maintain a coal plant that is less reliable and more costly than other generation resources.

I declare under penalty of perjury that, to the best of my knowledge, the foregoing is true and correct.

Executed this ____ day of _____, 2026.

Erin O'Neill

Erin O'Neill

Digitally signed by Erin O'Neill
Date: 2026.04.28 12:32:09 -06'00'

Electric Energy and Demand Forecast

This section summarizes Tri-State’s approach to development of its base electric energy and demand forecast, and forecast variations, for Phase I ERP scenario modeling. Key assumptions and resulting forecast data are provided, including for compliance with Commission Rule 3605(b).

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Description of Process

This subsection addresses forecast requirements in Commission Rule 3605(b)(IV). The base long-term load forecast is prepared utilizing input from each of Tri-State's Utility Member Systems every year. Tri-State has a four-state service territory, with 42 Utility Member Systems¹ and each consists of up to nine retail classes in which a bottom-up forecast methodology is employed.

Inputs

Gross Load Forecast

The primary source for historical retail data by each class of consumers is Rural Utilities Service (RUS) Form 7, which is compiled by each of Tri-State's Utility Member Systems after the end of each calendar year. Information by month and class on the number of accounts, energy use per account, total energy, and the average price of electricity is collected for each Member. In addition, data on large commercial accounts is gathered on RUS Form 345. Historical wholesale Utility Member System hourly demand and load shapes are generated using data obtained from Tri-State's member billing system, which pulls data from delivery point meters on Tri-State's system.

Weather data from 20 weather stations within Tri-State's region is supplied through DTN Meteorlogix. Tri-State's database includes temperature, heating and cooling degree-days, and precipitation. Weather normalizations of this data are used in forecasting models (defined as 10-year average values).

Tri-State obtains economic and demographic data from Woods & Poole Economics, Inc. (W&P) for the county/counties that make up each Utility Member System. The majority of data from W&P originates with the Bureau of Economic Analysis (BEA), an agency within the U.S. Department of Commerce. All projections of economic and demographic data have been performed by W&P. Tri-State uses more than 20 measures demographic data as well as of employment and income activity by sector from the W&P data set.

Tri-State incorporates data from ITRON's Residential Statistically Adjusted End-Use (SAE) models for the West Mountain region into residential use-per-customer forecasts. Residential use-per-customer estimates include projections related to household thermal efficiency, heating and cooling unit saturation, appliance efficiency, lighting efficiency, and household size.

Tri-State periodically conducts a Residential End-Use Survey to identify residential characteristics specific to each Member. Questions include data on type of heating and cooling technology, appliance data, and thermal shell metrics. Heating and cooling saturations by member as of the survey year are calibrated using the percent growth in technologies for the Rocky Mountain Region from the SAE model.

The electricity that Tri-State Utility Member Systems provide to their Member Consumers (retail customers) often competes with propane, natural gas and fuel oil as an energy source. Historical price data for these alternative energy sources is obtained annually from the U.S. Department of Energy's (DOE) Energy Information Administration (EIA) State Energy Data System, Petroleum Marketing Monthly and

¹ Beginning February 1, 2025, Tri-State anticipates having 39 Utility Member Systems.

Annual Energy Outlook. Tri-State bases its price projections for each of these alternative fuels on information from the EIA. These price projections for alternative fuels are exogenous drivers that are available for use in econometric model development and are incorporated as a variable into some member estimates for residential and commercial classes.

Using annual historical data from 2003 through 2021, historical trends, as well as future projections for demographic and economic drivers, lighting efficiency and household heating and cooling profiles, Tri-State's statistical models estimate future gross load and demand.

Input Adjustments to Gross Load Forecast

While the above inputs are used to derive Tri-State's gross load and demand by member, additional inputs are collected to calculate adjustments related to partial requirements, distributed generation, energy efficiency, and beneficial electrification.

Tri-State allows Utility Members to serve a portion of their load from non-Tri-State resources, including partial requirements and distributed energy generation.

Partial Requirements² reflects a reduction in Utility Member load due to the election of members to buy out of a portion of their wholesale contract. Tri-State offers Utility Members two versions of this. The first is "MAX," which allows a member to source a fixed amount of around the clock demand and energy from another provider. To estimate load for this option, Tri-State uses the expected contract start date, amount of demand, hours per month, and region. The second option, "MARS," allows a member to elect to purchase energy from another provider using supply of a utility-scale resource. To estimate MARS load, Tri-State collects data on the expected contract start date, name and type of resource, and region. In addition, Tri-State collects three-year historical average hourly load profile for a resource of similar size in close proximity for use in shaping the estimated hourly partial requirements output.

To model distributed generation resource load and demand, Tri-State utilizes the contract dates, resource type (such as wind, hydro, tracking solar, or non-tracking solar), nameplate, and average hourly history for three to five years.

Estimates for energy efficiency and beneficial electrification are calculated using ERP targets and data provided by a third-party vendor. They are layered onto load estimates – with energy efficiency being a reduction in energy and beneficial electrification increasing electricity – during post-processing by other modeling groups.

Demand response is modeled as a generating resource; Attachment B of the ERP Report (LKT-1) provides additional details related to these estimates. In the financial estimates, which are concerned with energy billed, demand response energy is shown *net of any load shifts*. That is, if load is shifting from a peak hour to a non-peak hour, it does not impact the amount of energy billed to a customer and is not shown in

² After beginning of Phase I scenario modeling, FERC accepted the withdrawal of Tri-State's partial requirements filing. Tri-State is working with its Members to revise the approach to partial requirements supply. Phase I scenario modeling reflects initial partial requirements elections and methodology.

billing estimates. Only the net change in energy billed to customers will be reflected in demand response aggregates in financial modeling.

Forecasting Process

Gross Load Forecast Process

The nine retail classes include residential, seasonal, irrigation, small commercial, large commercial, public authorities, streetlights, resales to RUS, and resales to others. Each retail class, with the exception of large commercial, is broken into the number of customers and use-per-customer, which are then modeled separately and aggregated to arrive at forecast energy. By separating the demand forecast into the use per-customer and customer components, Tri-State can better distinguish between the trends driving growth in the number of customers versus technology or weather impacts on customer-level usage. There is also a separate category for the Utility Member's own use.

For all forecasts except for Large Commercial and Own Use, the number of customers and the use-per-customer are projected using a combination of econometric techniques, time series regressions, and simple trend analyses that generally utilize 20 years of history. Time series regressions typically utilize Auto Regressive Integrated Moving Average (ARIMA) modeling over a period of 20 years of historical data. If a defensible and statistically significant model can't be found, analysts may use an average, often over 5 years. Energy for these classes is derived by multiplying the number of customers by use-per-customer. The Large Commercial class energy forecast used in the ERP are derived from the combination of a statistical regression model over 20 years of history and Form 345 projections, whichever is greater. Own use only has one customer, the Utility Member, and Tri-State forecasts the energy directly based on historical trend.

Forecasts of residential customers are derived through multivariate regression models with explanatory variables including, but not limited to, population, employment, and income. Other models for the number of customers may rely on forecasted employment, trend, or a historical average.

Use-per-customer is also modeled using econometric models or weighted averages. Multivariate regressions on use-per-customer generally consider trend and weather; residential use-per customer forecasts incorporate data on area lighting and appliance efficiency, heating and cooling profiles, and building thermal efficiency that are derived from end use surveys and the ITRON's SAE models for the West Mountain region. If there is not a good model fit for use-per-customer for the various classes, a five-year average is generally utilized as a default. The residential use forecast is an exception and utilizes the end-use model when possible.

Once the nine classes and own use are forecasted, Tri-State aggregates them and then applies a retail loss factor that is generally an average from recent history. Retail losses are added to the aggregate energy by class to arrive at total annual energy purchases for each Utility Member System across the resource planning period (RPP). For each member, the monthly load shapes are based upon the Seasonal Index method utilizing a 2x12 centered moving average. Monthly forecasts are then used to generate a calendarized hourly dispatch based upon on the most statistically representative months from the last five years of history. After all estimates are generated, a draft report is then sent to each Member for

their review and feedback; periodically Tri-State will incorporate Member-requested adjustments that reflect each Member's intimate knowledge of conditions in their area.

Once the forecasts are finalized and completed for each Utility Member System, the final step is forecast aggregation to arrive at gross forecasts for state, planning region, and Tri-State as a whole. During the annual update process, for members that are split either between a state or grid boundary, Tri-State uses an average of the last three calendar years to determine state and planning regions for the forecast. These splits are generally carried forward in forecast estimates for the entire planning period until a new full calendar year is available.

Gross Demand Forecast

The projected values of the Member Coincident Peak (MCP) gross demands are based upon an hourly load forecast. Hourly loads are generated for each calendar month by applying the projected purchased energy requirement to a corresponding normalized historical load duration curve. The resultant hourly loads are dispatched chronologically based upon known historical loads and seasonal indices from a calendarized representative month. Once individual members' hourly demand forecasts have been determined, they are summed to arrive at a total Tri-State hourly load forecast (using a bottom-up approach), allowing the system coincident peak demand to be established.

The peak period used for billing is defined as the period between 12:00 (noon) and 10:00 PM, Monday through Saturday, except certain holidays. The Tri-State aggregate billing peak is the sum of the individual member peaks from the hourly demand forecasts, which occur within the defined peak period. The Tri-State Coincident Peak (TCP) for capacity planning is the highest hourly sum of Utility Member System hourly demand forecasts. Tri-State's peak occurs in July throughout the planning period, as Tri-State is a summer peaking system. Of note, Tri-State aggregates demand by state and planning region in a manner similar to the aggregation for energy. Hourly profiles for energy efficiency, partial requirements, beneficial electrification, and distributed generation are layered onto gross demand forecasts within the expansion and production cost models. This total demand is used in the expansion plan for resource planning and transferred to the Hyperion financial model in a manner similar to energy, to arrive at demand served by Tri-State.

Additional details on energy efficiency, demand response, and beneficial electrification modeling assumptions can be found in Attachment B and G-3 of the ERP Report (LKT-1).

Process for Calculating or Incorporating Load Forecast Adjustments

Several adjustments are made to gross load to arrive at load served by Tri-State, including distributed generation, partial requirements, energy efficiency, and beneficial electrification.

Distributed generation (DG) is a subtraction from gross load to arrive at the Utility Member load served by Tri-State. Distributed generation forecasts consist of energy and demand forecasts on a project level for member self-supply options, including Board Policy 115 (renewable self-generation on Member Systems), Board Policy 119 (community solar on Member systems). To calculate energy served by behind the meter or distributed generation resources, Tri-State estimates load using load shapes based on a three-year hourly average. For new or prospective distributed generation resources, rather than using the three-year history for the resource, Tri-State forecasts the energy and demand by scaling the three-

year historical average hourly load profile by the relative nameplate size to an existing resource in close proximity and same technology type (for example, wind, tracking solar, non-tracking solar, hydro) over the contract period.

As of February 2023, Members have over 66 renewable or distribution generation projects, totaling 143 MW of capacity and capable of producing ~300 GWh/year are operating or under development. By capacity, approximately 85% of Utility Member System distributed generation is located in Colorado and 14% is in New Mexico. By technology, 81% of distributed generation is solar, 6% is wind, and 7% is waste heat, with the remaining comprised of hydro or landfill methane.

The calculation of Partial Requirements adjustments depends on whether the Member elected the MAX or MARS Partial Requirements option. For the MAX option, Tri-State uses the around-the-clock demand elected by the member and derives energy by multiplying the demand by the number of hours in the month. Under the MARS option, Tri-State estimates partial requirements energy by scaling the three-year historical average hourly load profile for a similar type resource in close proximity to the planned resource to the nameplate of the expected resource; the existing MARS Partial Required election is currently modeled as a tracking solar resource. Once Partial Requirements are operational, for MARS, Tri-State would use the three-year historical average to estimate the energy and demand. As Partial Requirements reflects energy that would be provided to the Member by third-party providers, the energy and demand is a reduction of gross Member energy and demand needs.

Energy efficiency estimates are compiled from multiple sources; annual Colorado energy efficiency estimates are calculated consistent with the 2020 ERP Phase I Settlement Agreement,³ with estimates derived as the target percentage by year multiplied by annual Colorado gross load net of partial requirements. These annual targets are shaped based on the weighted average of the aggressive incentive level of hourly program profiles provided by a third-party consultant for the Colorado load area. Annual energy efficiency potential for Wyoming and New Mexico, as well as hourly and monthly profiles for each planning region, are developed by compiling the individual measure and program hourly profiles into an hourly shape for each area and incentive level. Wyoming and New Mexico energy efficiency are not part of the native load, but rather a supply side resource option for the expansion model to select.

Energy efficiency estimates are a reduction of gross Member load in the calculation of load served by Tri-State. In contrast, beneficial electrification estimates, which are also calculated by a third-party consultant, are added to gross member load. These are layered onto the gross Member load estimates in Hyperion financial modeling.

Additional details on energy efficiency and beneficial electrification modeling assumptions can be found in Attachments B and G-3 of the ERP Report (LKT-1).

³ Section 3.11.9.

Range of Forecasts

This subsection addresses forecast requirements in Commission Rule 3605(b)(II). Tri-State developed a base forecast, as well as two forecast variations, including a low load and high load forecast. To develop the low load and high load forecasts, Tri-State established prediction intervals to express uncertainty around the expected value forecast. The total variance includes both economic and weather-related uncertainty. The low and high load intervals are generated at the 90% confidence interval, meaning that the actual value should be within the given interval with a probability of 90%.

Tri-State did not model resource planning scenarios related to the upper and lower 90% confidence intervals for the purpose of this Resource Plan. However, both the High Load forecast and Low Load forecast are presented in the following subsection, as well as in Attachment F-1 of the ERP Report (LKT-1).

Base Load Forecast

The gross Base Case load forecast of annual energy, and Tri-State summer and winter coincident peak (TCP) demand is shown, by year of the RPP, in Table 1 below, in compliance with Commission Rule 3605(b)(I)(A). Please note that the base forecast for this, and for all load data presented below and in Attachment F-1 (unless otherwise specified), is gross load, meaning it is gross of Partial Requirements, distributed generation, energy efficiency, beneficial electrification, demand response, member self-generation, and transmission losses. Partial Requirements load assumptions are provided in Table 2 below. Load for the three Utility Member Systems that have provided Tri-State with notice of their intent to depart the system has been excluded as of the noticed departure date.⁴ Of note, Tri-State’s winter peak is forecasted to shift to January in 2024 due to expected member departures; in all other years of the forecast, the winter peak occurs in December.

Table 1: Tri-State Gross Annual Energy, Summer Coincident Peak, and Winter Coincident Peak⁵

Year	Energy (MWh)	Summer Peak (MW)	Winter Peak (MW)
2024	14,325,075	2,419	2,230
2025	13,016,605	2,381	1,761
2026	13,027,503	2,403	1,779
2027	13,161,110	2,423	1,800
2028	13,310,698	2,448	1,807
2029	13,437,397	2,466	1,825
2030	13,578,717	2,489	1,845
2031	13,720,347	2,511	1,867
2032	13,875,367	2,536	1,887
2033	14,002,551	2,554	1,906
2034	14,149,447	2,578	1,927

⁴ United Power and NRPPD departures are May 1, 2024; Mountain Parks’ departure is January 15, 2025.

⁵ The energy and demand shown in the tables reflects the sum of member gross energy needs and excludes aggregates that were layered on top of the load forecast, including energy efficiency, beneficial electrification, and partial requirements.

2035	14,300,790	2,601	1,950
2036	14,468,551	2,628	1,973
2037	14,613,014	2,649	1,994
2038	14,771,813	2,674	2,017
2039	14,932,199	2,698	2,041
2040	15,101,613	2,725	2,064
2041	15,247,115	2,746	2,085
2042	15,405,534	2,770	2,108
2043	15,571,769	2,796	2,133

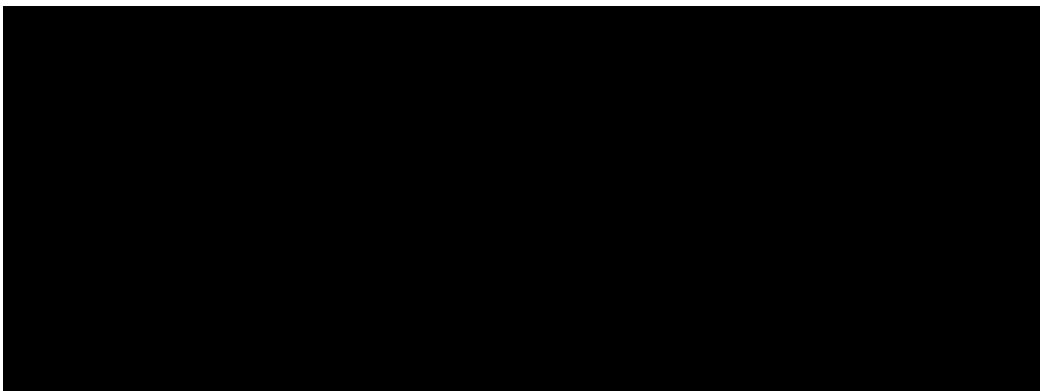
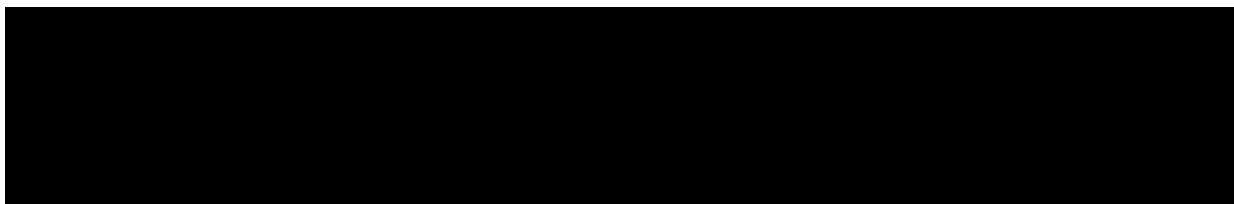


Table 3 details the relative share of Tri-State load forecasted in each state.

Table 3: Percentage of Tri-State Load by State, 2025 and 2030

	Colorado	New Mexico	Wyoming	Nebraska
2025	61%	19%	14%	7%
2030	62%	18%	14%	6%

Table 4 shows a comparison of base total member energy requirements forecast and the load that Tri-State expects to provide (before transmission losses). Of note, the share of energy provided by Tri-State to Members decreases starting in 2026 due to increased energy self-supplied by Members through partial requirements.



⁶ Variance reflects adjustments including partial requirements and Member distributed generation. The variance between Member gross load and load served by Tri-State increases in magnitude starting in 2026 due to the expected start of partial requirements.


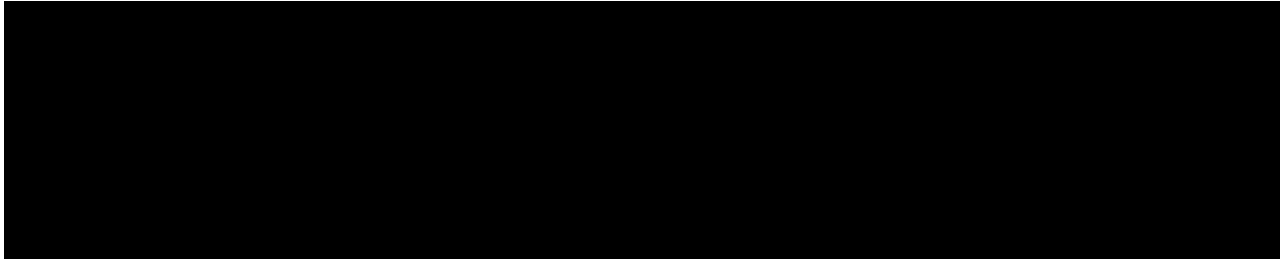


Table 5 reflects the difference of gross and net peak demand for select years throughout the RPP.



High Load Forecast

A number of factors exist which could significantly increase Tri-State's load above the base forecast. This includes:

- Delay in the departure of Utility System Members that have submitted exit notices to Tri-State or their inability to fully exit Tri-State.
- Delay of members to reduce their load from Partial Requirements, due to delay in regulatory approvals or supply chain issues. In the 2023 ERP Phase I modeling, all Partial Requirements load reductions are anticipated to start as of January 1, 2026.
- Increased demand resulting from higher than expected economic or population growth (including increased migration to the Tri-State service territory).
- Increased beneficial electrification, including faster than expected adoption of electric vehicles due to government incentives.

Low Load Forecast

Potential factors exist which could significantly reduce Tri-State's load, including:

- Increased Utility Member distributed generation beyond forecasted amounts due to trend and to Members taking advantage of IRA project funding.
- Higher than forecasted energy efficiency and demand-side management.
- Reduced demand stemming from increased inflation or economic downturns, and
- Load loss related to environmental and regulatory impacts from extractive industries, including natural gas, oil, and coal.

⁷ For simplicity, we are showing Tri-State peak demand net of both MAX and MARS partial requirements. Expected impact of Member self-generation under policies 115 and 119 are small. MARS partial requirements is reflected at 5% ELCC.

Utility Member Sales Forecasts

This subsection addresses forecast requirements in Commission Rule 3650(b)(1)(A). The following graphs show Tri-State’s load forecasts for the RPP for the Tri-State System. Tri-State’s annual system gross energy average growth from 2024-2043 is 0.44%, while gross summer coincident system demand has an annual average growth rate of 0.76%. Where appropriate, data is presented for a range of forecasts, including Base, High and Low Load forecasts.

Tri-State System Annual Energy Sales, Summer Peak & Winter Peak

The below graphs detail base, high load, and low load gross system annual energy sales, summer peak, and winter peak for the Resource Planning Period by year.

Figure 1: Tri-State System Annual Energy Sales to Utility Member Systems

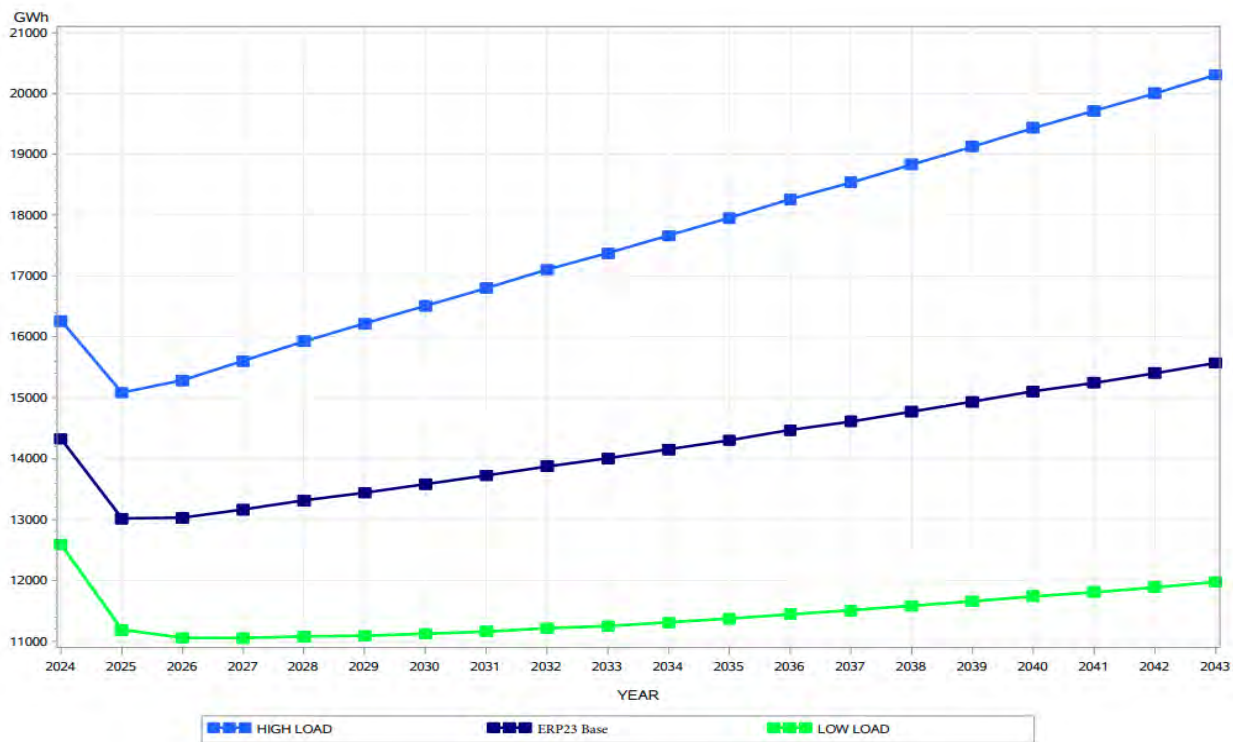


Figure 2: Tri-State System Annual Coincident Summer Peak

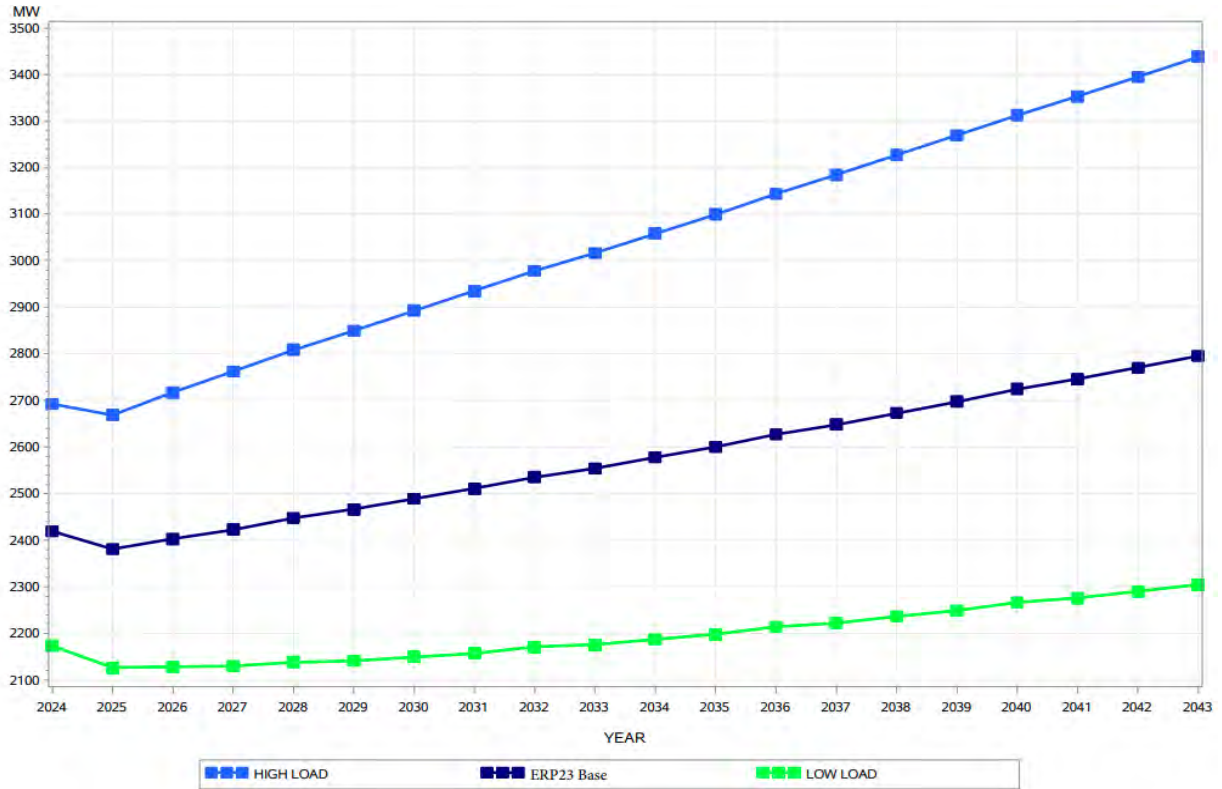
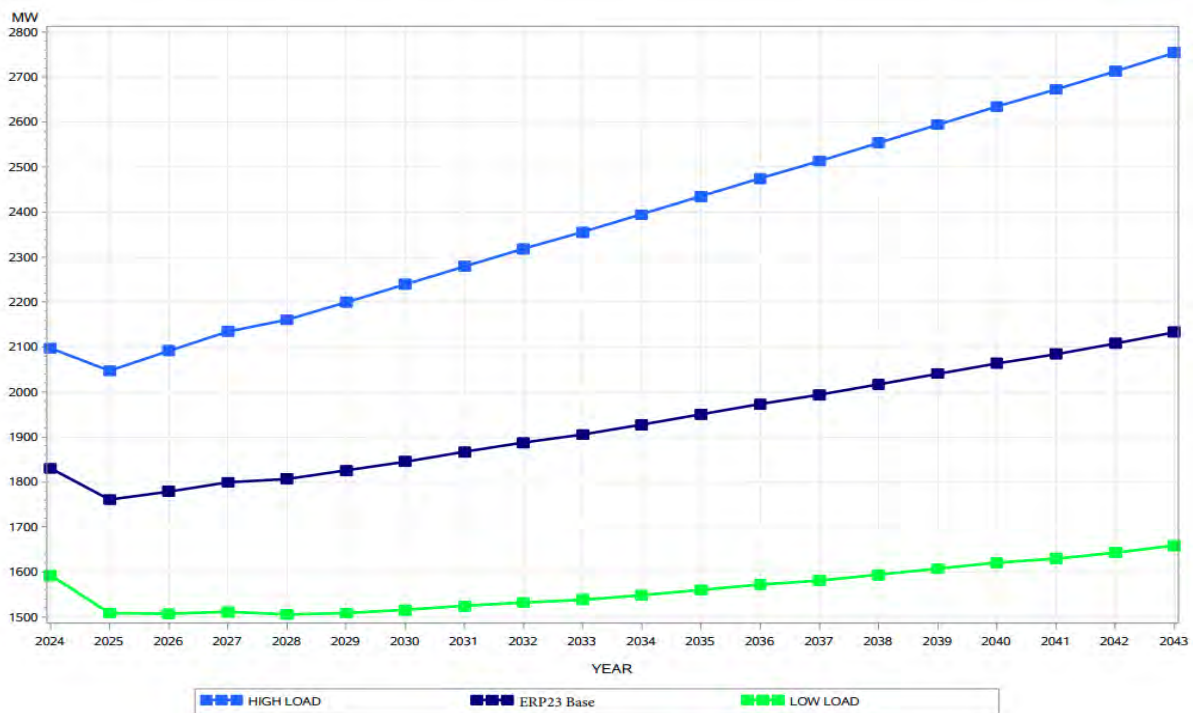


Figure 3: Tri-State System Annual Coincident Winter Peak



Additional graphs showing gross energy sales, winter peak, summer peak, and daily profiles for Tri-State, State, and Utility Member Systems can be found in Attachment F-1 of the ERP Report (LKT-1). Table 6 references the page in the attachment that corresponds to the compliance requirement.

Table 6: Reference Guide for Attachment F-1, Load Graphs by Member and State

Rule	Item	Granularity	Page(s)
3605(b)(I)(A)	Annual Energy Sales	States	1
3605(b)(I)(A)	Annual Energy Sales	Utility Member System	5
3605(b)(I)(A)	Annual Coincident Summer Peak	States	47
3605(b)(I)(A)	Annual Coincident Summer Peak	Utility Member System	51
3605(b)(I)(A)	Annual Coincident Winter Peak	States	93
3605(b)(I)(A)	Annual Coincident Winter Peak	Utility Member System	97
3605(b)(I)(E)	Hourly Peak Day By Calendar Month	States	139
3605(b)(I)(E)	Hourly Peak Day By Calendar Month	Utility Member System	187
3605(b)(I)(E)	Hourly Off-Peak Day by Calendar Month	States	656
3605(b)(I)(E)	Hourly Off-Peak Day by Calendar Month	Utility Member System	703
3605(b)(I)(E)	Hourly Average Day by Calendar Month	States	1171
3605(b)(I)(E)	Hourly Average Day by Calendar Month	Utility Member System	1219

Comparison of 2020 ERP Phase II to 2023 ERP Phase I Load Forecast⁸

The gross base load forecast—which is the sum of individual gross load member forecasts in the 2023 ERP Phase I—was produced in summer 2022 and is the same vintage of annual estimate that was used in the 2020 ERP Phase II due to timing of the long-term load forecasting cycle and a short time span between modeling for both ERPs. While the underlying estimates are the same for most members, the 2023 ERP base load forecast is lower due to the removal of load for members expected to depart in 2024 and 2025, as detailed above. The reduction in gross member energy attributed to member departures ranges from 2,288 GWh (14%) in 2024 to 5,254 GWh (26%) in 2040⁹ compared to 2020 ERP Phase II. The expected reduction in Tri-State’s gross system peak resulting from expected member departures ranges from 646 MW in 2024 (21%) to 966 MW in 2040 (26%). Graphs of the 2020 ERP Phase II (with upper and lower confidence intervals) and the 2023 ERP Phase I gross member load, summer, and winter coincident peaks are shown below.

⁸ Rule 3605(b)(III).

⁹ 2040 values are shown as 2040 was the final year modeled in the 2020 ERP Phase II.

Figure 4: Tri-State System Annual Energy Sales to Utility Member Systems

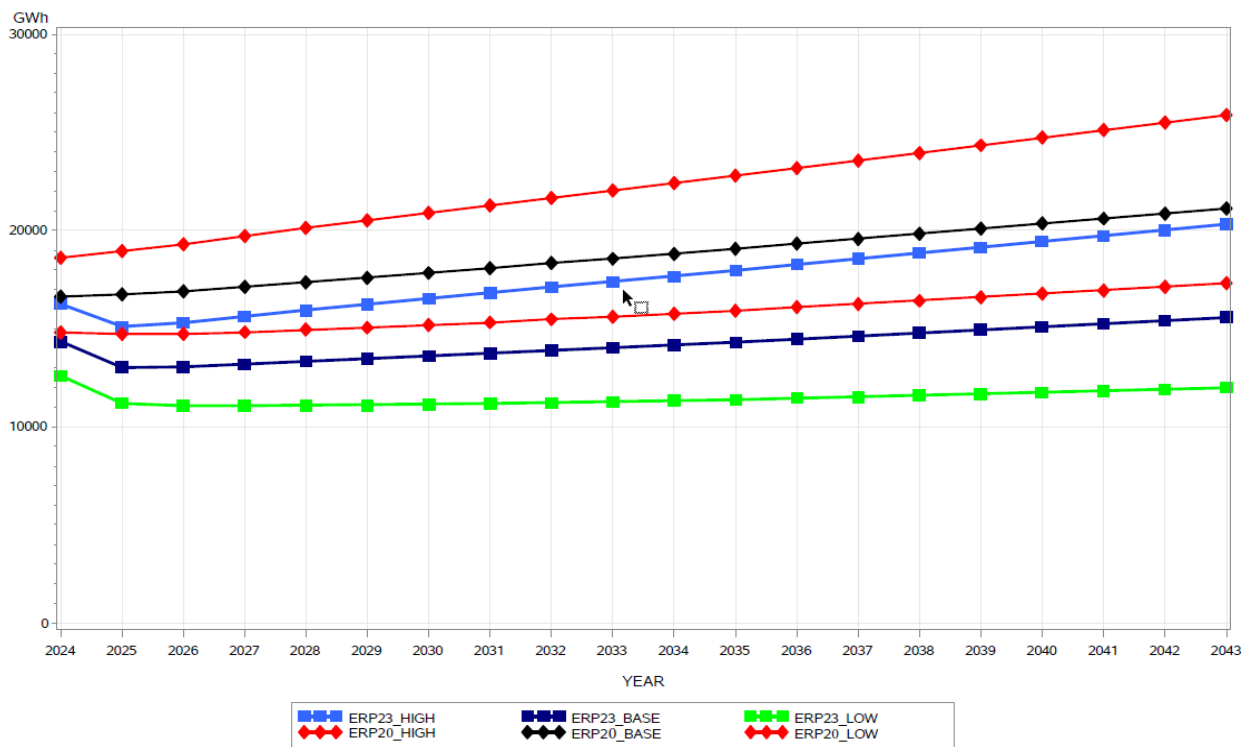


Figure 5: Tri-State System Annual Summer Coincident Peak

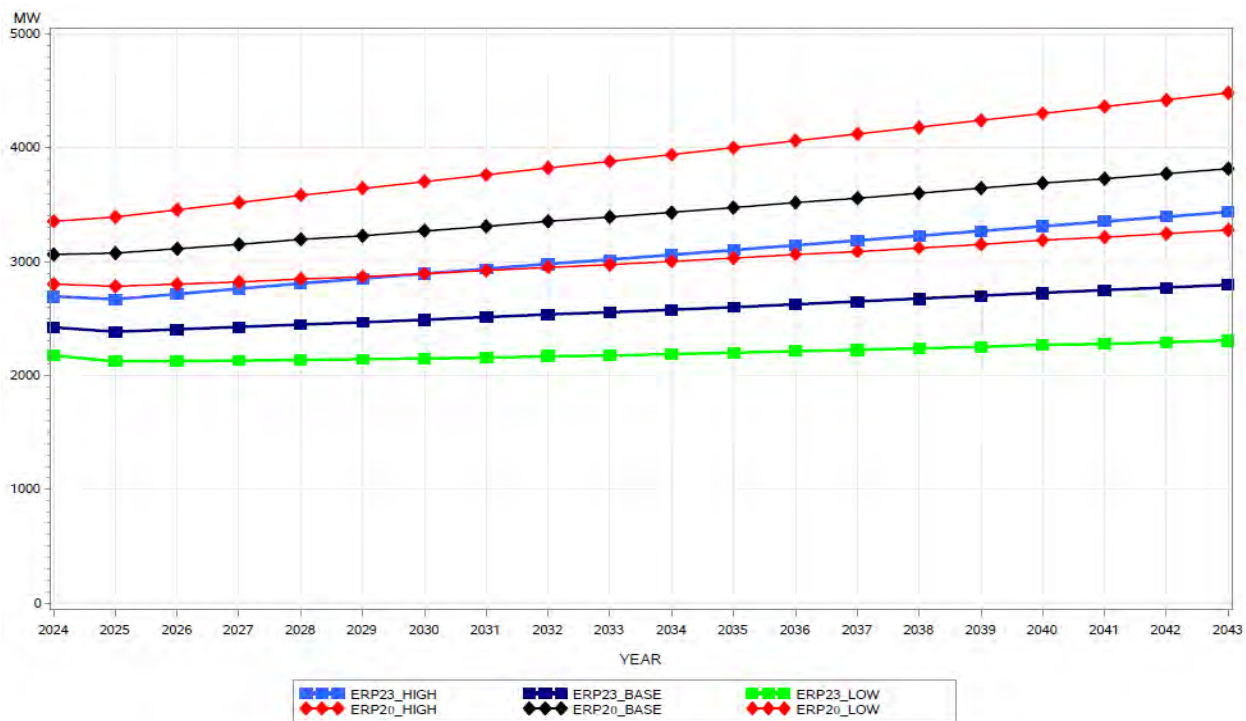
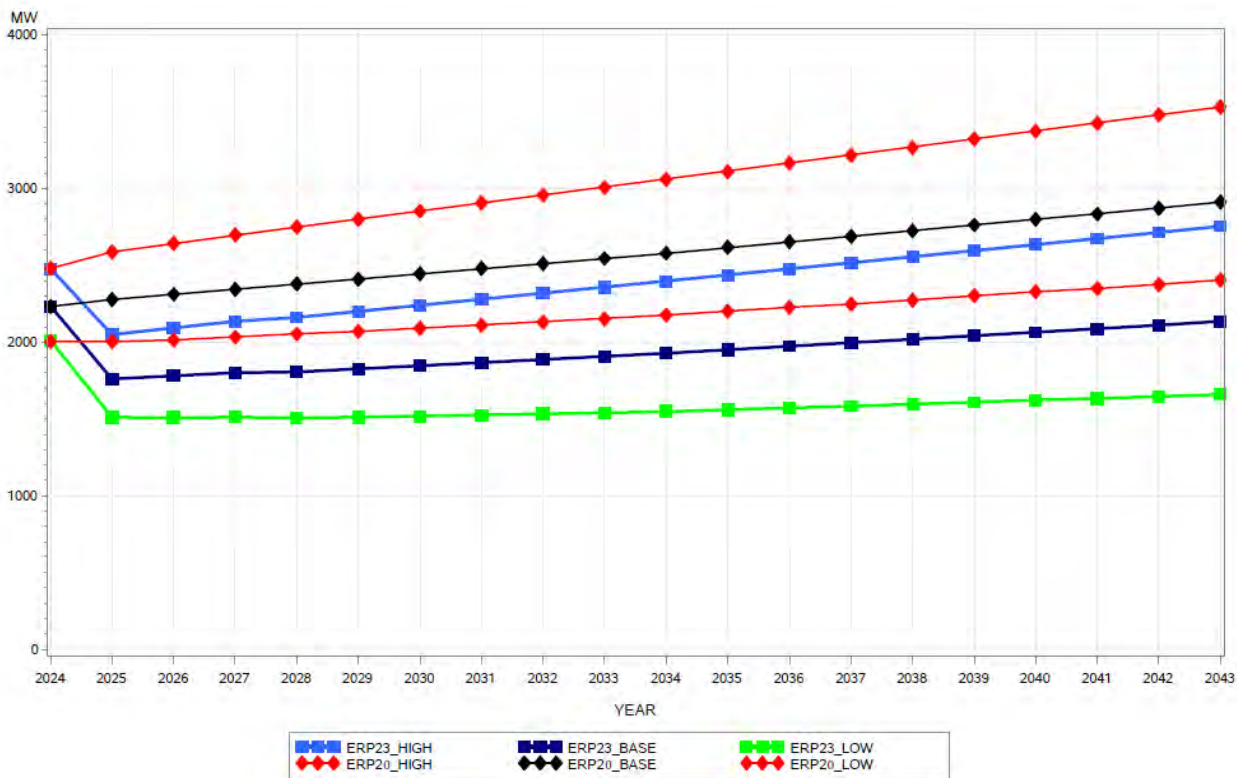
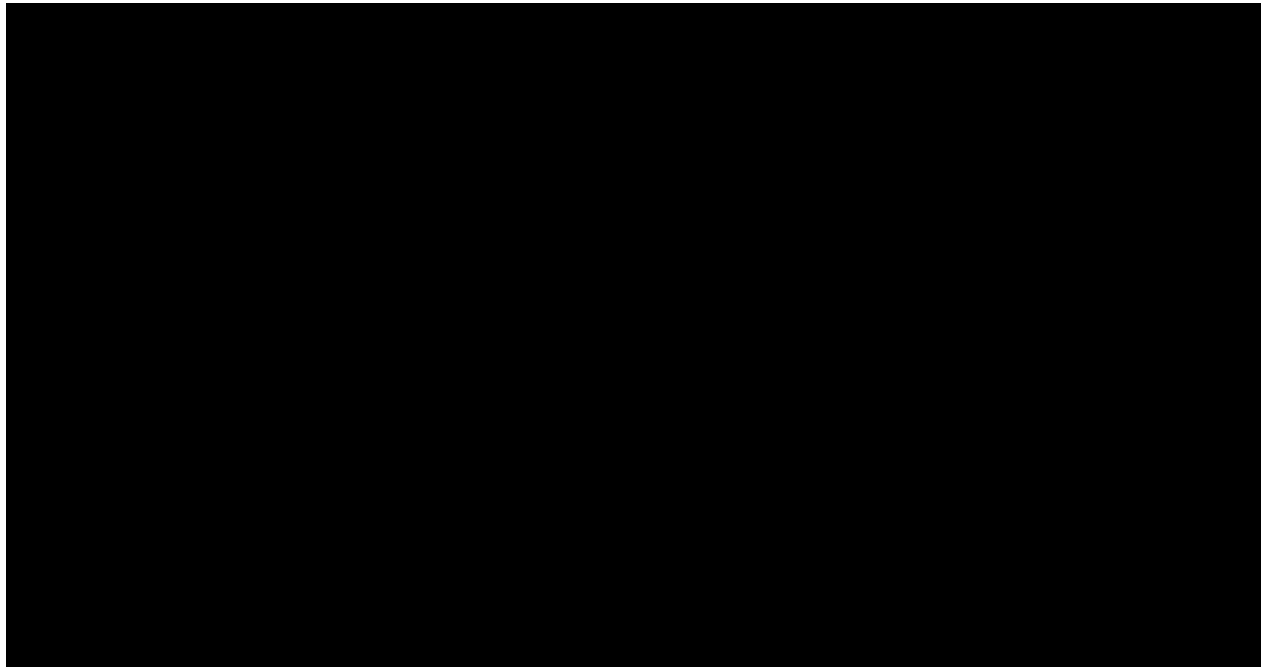


Figure 6: Tri-State System Annual Winter Coincident Peak



When comparing the 2023 ERP Phase I load that Tri-State is expecting to serve (inclusive of adjustments) to the 2020 ERP Phase II load, Tri-State made additional adjustments, as noted above. These include the delay of partial requirements to 2026, addition of beneficial electrification, change in energy efficiency targets as a result of member exits, and changes to member-supplied energy contracts, such as community solar. In the 2020 ERP Phase II, Tri-State modeled 300 MW of Partial requirements, with 233 MW starting as of January 1, 2024 and the remaining 67 MW beginning on January 1, 2025. Table 7 below shows the changes and the variance as a percent of 2020 ERP Phase II expected load deliveries for select years.



Comparison of Historical Forecasts & Actuals

Tables 8 through 10 show the energy sales, summer peak, and winter peak for the prior five years of actuals as well as the annual forecasts in the most recently filed resource plan to the annual forecasts in the current resource plan, in accordance with Commission Rule 3605 (b)(III).

Table 8: Tri-State System Annual Energy Sales to Utility Member Systems (GWh)

YEAR	BASE FORECAST			HIGH LOAD		LOW LOAD	
	ACTUALS	ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023
2018	16,179
2019	16,203
2020	15,983
2021	16,037
2022	16,872
2023	.	16,370	16,370	18,059	18,108	14,809	14,776
2024	.	16,613	14,325	18,610	16,259	14,792	12,586
2025	.	16,733	13,017	18,956	15,084	14,727	11,190
2026	.	16,879	13,028	19,292	15,285	14,722	11,058
2027	.	17,110	13,161	19,701	15,604	14,812	11,053
2028	.	17,360	13,311	20,118	15,927	14,933	11,076
2029	.	17,583	13,437	20,494	16,214	15,041	11,089
2030	.	17,824	13,579	20,882	16,511	15,171	11,122
2031	.	18,065	13,720	21,265	16,802	15,308	11,161
2032	.	18,323	13,875	21,662	17,106	15,463	11,216
2033	.	18,547	14,003	22,018	17,372	15,593	11,251
2034	.	18,794	14,149	22,397	17,659	15,746	11,306
2035	.	19,046	14,301	22,780	17,950	15,905	11,368
2036	.	19,318	14,469	23,184	18,258	16,083	11,445
2037	.	19,561	14,613	23,554	18,537	16,239	11,505
2038	.	19,821	14,772	23,942	18,832	16,411	11,579
2039	.	20,083	14,932	24,332	19,128	16,585	11,656
2040	.	20,356	15,102	24,733	19,434	16,770	11,741
2041	.	20,600	15,247	25,100	19,710	16,932	11,808
2042	.	20,859	15,406	25,484	20,002	17,108	11,887
2043	.	21,128	15,572	25,880	20,303	17,292	11,973

Table 9: Tri-State System Annual Summer Coincident Peak (MW)

YEAR	BASE FORECAST			HIGH LOAD		LOW LOAD	
	ACTUALS	ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023
2018	2,887
2019	2,922
2020	2,896
2021	2,975
2022	3,070
2023	.	3,023	3,023	3,269	3,274	2,796	2,793
2024	.	3,065	2,419	3,352	2,693	2,803	2,173
2025	.	3,073	2,381	3,393	2,669	2,785	2,126
2026	.	3,113	2,403	3,458	2,718	2,804	2,128
2027	.	3,151	2,423	3,521	2,762	2,823	2,130
2028	.	3,194	2,448	3,585	2,809	2,849	2,139
2029	.	3,230	2,466	3,643	2,850	2,868	2,141
2030	.	3,271	2,489	3,704	2,893	2,894	2,150
2031	.	3,310	2,511	3,763	2,935	2,920	2,157
2032	.	3,355	2,536	3,825	2,978	2,951	2,171
2033	.	3,390	2,554	3,880	3,017	2,972	2,176
2034	.	3,433	2,578	3,941	3,059	3,002	2,187
2035	.	3,473	2,601	4,000	3,100	3,030	2,198
2036	.	3,520	2,628	4,062	3,144	3,065	2,214
2037	.	3,559	2,649	4,120	3,184	3,090	2,223
2038	.	3,602	2,674	4,181	3,227	3,122	2,237
2039	.	3,645	2,698	4,241	3,270	3,153	2,249
2040	.	3,691	2,725	4,303	3,313	3,188	2,267
2041	.	3,730	2,746	4,360	3,353	3,214	2,276
2042	.	3,773	2,770	4,420	3,395	3,246	2,290
2043	.	3,817	2,796	4,482	3,438	3,278	2,304

Table 10: Tri-State System Annual Winter Coincident Peak (MW)

YEAR	ACTUALS	BASE FORECAST		HIGH LOAD		LOW LOAD	
		ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023	ERP 2020 PHASE II	ERP 2023
2018	2,233
2019	2,199
2020	2,106
2021	2,120
2022	2,322
2023	.	2,245	2,231	2,491	2,475	2,019	2,009
2024	.	2,276	2,230	2,556	2,098	2,021	1,592
2025	.	2,279	1,761	2,586	2,047	2,003	1,509
2026	.	2,310	1,779	2,641	2,092	2,015	1,507
2027	.	2,344	1,800	2,696	2,135	2,031	1,511
2028	.	2,378	1,807	2,750	2,161	2,051	1,506
2029	.	2,409	1,825	2,801	2,200	2,067	1,509
2030	.	2,443	1,845	2,853	2,240	2,087	1,515
2031	.	2,478	1,867	2,905	2,279	2,110	1,525
2032	.	2,512	1,887	2,956	2,318	2,132	1,533
2033	.	2,544	1,906	3,006	2,355	2,151	1,539
2034	.	2,579	1,927	3,057	2,394	2,174	1,548
2035	.	2,616	1,950	3,110	2,434	2,200	1,561
2036	.	2,653	1,973	3,163	2,475	2,225	1,572
2037	.	2,687	1,994	3,215	2,513	2,247	1,581
2038	.	2,724	2,017	3,268	2,554	2,273	1,594
2039	.	2,762	2,041	3,321	2,594	2,300	1,608
2040	.	2,799	2,064	3,374	2,634	2,326	1,620
2041	.	2,833	2,085	3,425	2,673	2,349	1,630
2042	.	2,870	2,108	3,478	2,713	2,376	1,643
2043	.	2,910	2,133	3,532	2,755	2,405	1,659

Other Load Aggregates and Impacts

Losses¹⁰

Tri-State adds a 3.5% transmission loss factor to load across Tri-State’s system in the Western Interconnection, excluding in the PNM BA area¹¹, for modeling purposes. Tri-State load in the Western Interconnection is located in multiple BA and TP systems. The 3.5% transmission loss factor is meant to represent an average of expected transmission losses. Tri-State’s load in the Eastern Interconnection is covered by a full requirements contract.

¹⁰ Rule 3605(b)(I)(D).

¹¹ Losses in PNM BA are handled financially and included in the financial forecast.

Energy and Capacity Sales to Other Utilities¹²

Annual contract energy and capacity sales to other utilities and counterparties are described in Attachment B of the ERP Report (LKT-1), as well as modeled proxy sales in anticipation of the ability to sell excess power upon Member exits.

Intra-Utility Energy and Capacity Use¹³

Tri-State intra-utility loads consist of a number of service centers and the headquarters building. For these loads, Tri-State takes retail service from the local provider. Accordingly, Tri-State has no intra-utility loads that contribute to energy and capacity requirements for purposes of Tri-State resource planning.

Potential Benefits of Strategically Locating Distributed Energy Storage within Member Cooperative Territories

Tri-State allows for distributed energy storage projects through Tri-State Board Policy 115. Members elect whether or not to pursue Policy 115 projects, including determination of technology type, project size (within policy limitations), and project location. Tri-State works with interested Members to develop programs that are beneficial, while minimizing program impacts to all Members.

¹² Rule 3605(b)(1)(B).

¹³ Rule 3605(b)(1)(C).

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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)

Order No. 202-26-21

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

Exhibit CCC: State of Colorado, The State of Colorado's Request for Rehearing, Motion
to Intervene, and Stay Request (Jan. 28, 2026)

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I. Introduction

On December 30, 2025, the Department of Energy (“Department”) issued Order No. 202-25-14 (“Order”)¹ pursuant to its emergency authority under Section 202(c) of the Federal Power Act (“FPA”)² (“Section 202(c)”) to prevent the scheduled retirement of a coal-fired generating unit at the Craig Power Station in Moffat County, Colorado. The Order requires the availability of one coal-fired unit (“Craig Unit 1”) from December 30, 2025, to March 30, 2026.

There is no emergency justifying the Department’s Order, and even if there were, preventing the retirement of Craig Unit 1 is not the best (or even a reasonable) way to meet the alleged emergency, and does not serve the public interest. The FPA limits the use of Section 202(c) to addressing specific, imminent capacity shortfalls resulting from unexpected outages, natural disasters, extreme weather, and similar circumstances. Here, the Department has declared an emergency due to “a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes” in the Western Electricity Coordinating Council (“WECC”) Northwest assessment area.³ But the Order’s emergency determination cannot stand against even the mildest scrutiny.

There is no energy “emergency” as defined by Section 202(c) in the WECC-Northwest assessment area, in Colorado, or in any of the states served by Craig Unit 1. Rather, the Unit’s owners and their respective state utility commissions have been

¹ Exhibit A (Department, Order No. 202-25-14 (Dec. 30, 2025) (“Order”).

² 16 U.S.C. § 824a(c).

³ Exhibit A, at 1.

planning for Craig Unit 1's retirement for the last decade.⁴ These comprehensive planning processes have ensured that there are reliable and affordable resources available to meet the energy needs in the areas served by Craig Unit 1, such that its long-planned retirement does not create an emergency.

The Department's illegal use of its Section 202(c) authority to require the continued availability of Craig Unit 1, unsupported by any evidence of an imminent energy emergency, will result in unnecessary operational and maintenance costs that could be imposed on ratepayers in Colorado and potentially other states. Continued operation of Craig Unit 1 pursuant to the Order would also cause needless pollution emitted into Colorado and its neighboring states, which the Department failed to meaningfully consider or address, as it was required to do. The Order illegally intrudes on the authority of the states to ensure the resource adequacy of their electric grids and to dictate energy policy within their borders, and improperly attempts to impose the administration's policy preferences on state ratepayers.

Pursuant to Section 3131 of the FPA,⁵ the Colorado Attorney General, on behalf of the State of Colorado, timely submits this request for rehearing and motion to intervene ("Request") seeking rehearing of the Order. The Department should grant rehearing and rescind the Order because it is an unlawful abuse of the Department's emergency authority, is unsupported by evidence showing a true emergency, and is arbitrary and capricious.

⁴ Exhibit C (Declaration of Erin O'Neil (Jan. 26, 2026)), ¶ 32.

⁵ 16 U.S.C. § 8251.

II. Motion To Intervene

The State of Colorado moves to intervene in the proceeding initiated by the Order and become a party for purposes of Section 313/ of the FPA.⁶ The State of Colorado is aggrieved by the Order in several ways.

First, households and businesses in Colorado could be required to pay higher electricity bills because of the Order.⁷ Through a carefully planned process driven by economic considerations, the owners of Craig Unit 1 planned to retire the Unit and replace it with more cost-effective facilities.⁸ By ordering the continued operation of Craig Unit 1, the Order guarantees that Tri-State Generation and Transmission Association, Inc. (“Tri-State”), PacifiCorp, Platte River Power Authority (“PRPA”), Salt River Project, and Public Service Company of Colorado (“Public Service”) (together, “Craig Unit 1 Owners”), will incur higher costs to serve their members and customers, which they will then likely seek to pass on to their electricity consumers, including rural customers in Colorado.⁹ Although the precise costs and the cost recovery methods are not yet known, it is likely that Colorado ratepayers will bear substantial new costs above what they would have paid absent the Order.¹⁰

⁶ 16 U.S.C. § 825I.

⁷ Exhibit D (Declaration of Joseph Pereira (Jan. 26, 2026)). Because the Order directs the Craig Unit 1 Owners to seek cost recovery the possibility of increased rates is a foreseeable harm for Colorado. Exhibit A, ¶ E. However, Colorado reserves all rights to dispute that costs incurred based on the Order are appropriate.

⁸ Tri-State, [Reliable, Lowest-Cost, Reduced Emissions Preferred Portfolio Focus of Tri-State Resource Plan Filing](#) (Apr. 11, 2025) (last visited Jan. 26, 2026).

⁹ Exhibit D, ¶ 11, 18.

¹⁰ Exhibit D.

Second, the Craig Unit 1 Owners determined that it is prudent to retire Craig Unit 1 and replace it with more reliable and cost-effective resources. And the Colorado Public Utilities Commission (“CoPUC”) determined that retiring Craig Unit 1 will not affect Tri-State’s resource adequacy.¹¹ By delaying the retirement of a 45 year old coal-fired unit that was not even operable at the time the Order was issued, the Department is causing Colorado’s electric customers to be served by a more costly and less reliable and resilient electric grid. Instead of continuing to invest and develop more reliable resources as planned, the Craig Unit 1 Owners will have to dedicate resources to repair and maintain a coal plant that is less reliable and more costly than other generation resources.

Third, Colorado will suffer environmental harms if Craig Unit 1 is required to operate based on the Order. Craig Unit 1 is a significant source of particulate matter (“PM”), nitrogen oxides (“NOx”), sulfur dioxide (“SOx”), carbon monoxide (“CO”), mercury, hazardous air pollutants (HAPs), and greenhouse gas (“GHG”) emissions, and its scheduled retirement would have resulted in significant emissions reductions.¹² The Order does not make a meaningful attempt to minimize or mitigate the emissions impact of continued operation of Craig Unit 1 as required. Operating Craig Unit 1 beyond its planned retirement date will increase the amount of pollution emitted in Colorado, harming the environment, public health, and welfare, as well as Colorado’s ability to comply with other federal and state environmental laws.¹³

¹¹ See e.g., Exhibit E (CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E), at ¶ 116; CoPUC, Decision No. R22-0191, issued on March 28, 2022, in Proceeding No. 20A-0528E.

¹² Exhibit B, ¶¶ 13-18.

¹³ See generally, *infra*; Exhibit B, at 15-22.

Finally, state authority over generation resources has been a bedrock principle of the FPA for nearly a century. Federal intrusion in this traditional sphere of state control is permitted only in a true emergency and only with specific procedures that the Department did not follow when issuing the Order. Colorado's sovereign interest in seeing its state laws followed in an area reserved to state sovereign authority further warrants the State's intervention.

III. Background

The Order makes several claims about Colorado's energy resource mix, expected increases in energy demand in the region, and the resulting need for continued availability of Craig Unit 1 to address an alleged energy emergency. The facts on the ground tell a very different story.

A. **Craig Unit 1 is owned by several utilities with specific service areas.**

Craig Unit 1, along with Craig Units 2 and 3, comprise Craig Station, a 1,285 megawatt ("MW"), generating facility in Moffat County, CO.¹⁴ Craig Units 1 and 2, also known as the Yampa Project, are operated solely by Tri-State but are co-owned by Craig Unit 1 Owners. Craig Unit 1 has a 427 MW capacity and began operating in 1980, making it over 45 years old.¹⁵ Craig Unit 1 was approved to retire on December 31, 2025. Craig Unit 2, which has a 410 MW capacity, has an approved retirement date of September 30, 2028, and Craig Unit 3, which is solely owned and operated by Tri-

¹⁴ *Craig Station Unit 2 owners announce retirement date of Sept. 30, 2028*, Tri-State (July 8, 2020), (last visited Jan. 26, 2026); Exhibit F (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding no. 20A-0528E, Attachment BN-2, (Tri-State, 2020 IRP/ERP, Public (Dec. 1, 2020)), at 182.

¹⁵ Global Energy Monitor, a project of the Sierra Club, [Craig Station](#) (last updated Jan. 5, 2026) (last visited Jan. 26, 2026); Exhibit F, at 182.

State and has a 448 MW capacity, will retire by 2030.¹⁶ It is Colorado's understanding that, when operating, Craig Unit 1 primarily provides energy to Colorado, as 51% of the unit is owned by Colorado utilities and it is located in Colorado, but provides some energy to Wyoming and Utah, and indirectly to Arizona.

Tri-State is a wholesale electric generation and transmission cooperative association with members located across Colorado, Nebraska, New Mexico, and Wyoming. Tri-State is a non-profit corporation and is owned and governed by its members through a Board of Directors.¹⁷ Tri-State's board is responsible for approving rates, major capital investments, and resource planning decisions.¹⁸ These resource planning decisions must then be approved by the CoPUC. Tri-State's ownership share of Craig Unit 1 is 24%, and Tri-State therefore is entitled to 102.5 MW out of Craig Unit 1's 427 MW capacity.¹⁹ It is Colorado's understanding that within Tri-State's service territory, only Colorado and Wyoming receive energy from Craig Unit 1.

PRPA and Public Service are the two other Colorado-based utilities with an ownership stake in Craig Unit 1. PRPA is a non-profit community-owned power generation and transmission utility that provides energy to Estes Park, Fort Collins, Longmont, and Loveland, Colorado.²⁰ PRPA has an 18% ownership share of Craig Unit 1

¹⁶Tri-State, [Craig Station Unit 2 Retirement](#) (July 8, 2020); Exhibit F, at 182; Exhibit G (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1 (Tri-State, Responsible Energy Plan ("Responsible Energy Plan") (Jan. 2020)), at 3.

¹⁷ Exhibit JJ (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E), at 13:8-13.

¹⁸ *Id.*, at 13:16-22.

¹⁹ Exhibit J (CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E).

²⁰ Exhibit EE (PRPA, [2024 Integrated Resource Plan](#) (Apr. 2023)).

and therefore is entitled to 77 MW of Craig Unit 1's capacity.²¹ Public Service is a subsidiary of Xcel Energy, Inc., and is the largest gas and electric provider in Colorado. However, Public Service has the smallest ownership stake in Craig Unit 1, owning 9% (38.4 MW of the unit's total capacity).²²

The Salt River Project and PacifiCorp are the two non-Colorado owners of Craig Unit 1. The Salt River Project is a non-profit organization that provides power in central Arizona.²³ The Salt River Project owns 29% of Craig Unit 1 (124 MW of the unit's total capacity).²⁴ However, the Salt River Project does not receive energy from Craig Unit 1 directly and instead trades for it through the Western Area Power Administration ("WAPA"). Their contract for exchanging this power through WAPA will expire on April 1, 2026. PacifiCorp is based in Oregon but serves customers in Oregon, Washington, California, Utah, Idaho, and Wyoming. PacifiCorp has a 19% ownership of Craig Unit 1 (81 MW of the unit's total capacity). It is Colorado's understanding that within PacifiCorp's service territory, only Utah and Wyoming receive energy from Craig Unit 1.

B. The Craig Unit 1 Owners decided to retire Craig Unit 1 ten years ago and included the retirement in their resource plans.

In 2016, the Craig Unit 1 Owners voluntarily decided to retire Craig Unit 1 by December 31, 2025, based on "the state and federal regulatory environment for coal-based generation, current and forecasted market conditions, the significant costs to

²¹ Exhibit FF (PRPA, [Craig Units 1&2 \(Yampa Project\)](#) (2026)).

²² [Craig Station](#), Global Energy Monitor.

²³ Exhibit H (Salt River Project, [2023 Integrated Systems Plan](#)) at 6.

²⁴ *Id.*, at 27.

install additional emissions controls, and the best interests of electric consumers.”²⁵

The Craig Unit 1 Owners agreed to proposed revisions to Air Quality Control Commission Regulation No. 23 and Colorado’s Regional Haze State Implementation Plan (“SIP”) that included the December 31, 2025 retirement date.²⁶ The U.S. Environmental Protection Agency (“EPA”) approved Craig Unit 1’s retirement date on July 5, 2018.²⁷ Since 2016, the Craig Unit 1 Owners have incorporated the planned closure of the unit as an assumption in all ERP proceedings, reports, decisions and modeling.²⁸ None of these processes or reports conclude that resource adequacy or reliability would be threatened by the unit’s retirement.

Tri-States’ resource plans are overseen by the CoPUC. The CoPUC reviewed Tri-State’s load forecasts, resource needs, and planned resource acquisitions, all of which included the retirement of Craig Unit 1 by December 31, 2025 as an underlying assumption, as part of Tri-State’s 2020 ERP and most recently its 2023 ERP for planning years 2026-2031.²⁹ As recently as August 2025, the CoPUC found that “Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP. Every portfolio that Tri-State modeled for its most recent ERP

²⁵ Tri-State, [Craig Station Owners, Regulators and Environmental Groups Reach Agreement on Proposed Revisions to Colorado Regional Haze Plan](#) (Sept. 1, 2016).

²⁶ See *id.*; 5 Colo. Code Reg. § 1001-27, Part A, Section IV.D.1 (2025).

²⁷ Air Plan Partial Approval and Partial Disapproval; Colorado; Regional Haze Plan for the Second Implementation Period, 83 Fed. Reg. 31,332 (July 5, 2018).

²⁸ Tri-State, [Craig Station Owners Agreement](#); e.g., CoPUC, *Tri-State, ERP Annual Progress Report, Revised*, filed on June 2, 2017, in Proceeding No. 15M-0852E, at 16; CoPUC, ERP for Annual Progress Report, filed on October 31, 2018, in Proceeding No. 15M-0852E, at 17; CoPUC, ERP Annual Progress Report, filed on December 10, 2019, in Proceeding No. 15M-0852E, at 22.

²⁹ Exhibit F, at 31; CoPUC, 150-Day Report, Public, filed on February 13, 2023, in Proceeding No. 20A-0528E, at 28; 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)), at 19, 21, 32, 44, 55, 66; Exhibit J, at 21, 32, 43, 54, 64, 75.

assumes that Craig Unit 1 retires at the end of 2025. . . every portfolio meets all reliability metrics and is reliable.” The CoPUC further found that Tri-State’s resource plan—including the retirement of Craig Unit 1—is resource diverse and cost effective, ensuring energy security, economic prosperity, and environmental protection. And the ERP progress report filed by Tri-State on December 1, 2025, did not present any resource adequacy or reliability issues, and continues to project no capacity shortfalls through 2035. Tri-State reaffirmed on January 23rd that the Craig Unit 1 retirement “has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit’s retirement.”³⁰ Public Service, which also engages in the ERP process with the CoPUC for review of its resource adequacy and reliability, has not indicated in its CoPUC filings a need for energy from Craig Unit 1 to meet any immediate or longer-term resource needs. Neither has PRPA, which conducts its own integrated resource planning process.

The other Craig Unit 1 Owners are subject to similar oversight by their state utility commissions, and since Tri-State’s service territory also includes Wyoming, its extensive planning addresses resource adequacy there as well. As part of their respective state-approved resource plans, Salt River Project and PacifiCorp have confirmed there are no resource adequacy concerns in their respective states associated with the retirement of Craig Unit 1.

³⁰ Tri-State, [Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order](#) (Jan. 23, 2026).

Underscoring the lack of need for Craig Unit 1, the unit suffered an outage on December 19, 2025 due to a mechanical failure of a valve.³¹ Absent the Order, it is unlikely the Owners would have expended new resources to repair the aging unit given that they were not expecting to use it to generate energy after December 31st.

C. Federal Energy Regulatory Commission (“FERC”) and its designated entities also oversee resource planning decisions for Craig Station to ensure reliability.

The structure of FERC’s management of the bulk power system is important to understand various studies and reports as they relate to the claimed emergency identified in the Order. The Craig Unit 1 Owners are currently not part of a Regional Transmission Organization (“RTO”) or Independent System Operator (“ISO”). The reliability and resource adequacy of the electric power system in states that are not in RTOs or ISOs are typically managed by individual utilities, which are often vertically integrated, meaning they handle generation, transmission, and distribution of electricity within their service areas, and are typically overseen by state public utilities commissions or a similar state entity.³² Although the utilities served by Craig Unit 1 are not in an RTO or ISO, they are subject to reliability oversight by FERC and several balancing authorities, in addition to being managed by their state resource planning and reliability requirements. These related processes are designed to govern long-term planning and resource adequacy, and are reserved to FERC and the states under the FPA.³³

³¹ Exhibit QQ (Tri-State, [U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating for Next 90 Days](#) (Dec. 31, 2025)); see also Exhibit B, ¶ 11; Exhibit D, ¶ 15.

³² FERC (Office of Public Participation), [Energy Markets](#) (last updated August 18, 2025) (last visited Jan. 26, 2026).

³³ See 16 U.S.C. § 824(b)(1); 16 U.S.C. § 824a(b).

FERC oversees the reliability of the bulk power system, which is the network of generation, transmission, and distribution system components across the United States, by reviewing, approving, and enforcing mandatory reliability standards developed by the North American Electric Reliability Corporation (“NERC”).³⁴ FERC designated NERC as the Electric Reliability Organization (“ERO”) for the mainland United States in 2006 pursuant to the Energy Policy Act of 2005.³⁵ NERC is a non-profit international regulatory authority that assures the reliability of North America’s bulk power system by creating reliability standards, approved by FERC, that are legally enforceable and include training and communications requirements, and emergency back up plans.³⁶ These standards apply to all users, owners, and operators of the continental United States’ bulk power system.³⁷ NERC also annually analyzes seasonal and long-term reliability of the bulk power system and assess risk by region using a three-tiered system.³⁸

NERC is permitted to delegate authority to regional entities for the purpose of proposing and enforcing reliability standards.³⁹ NERC therefore divides the North American bulk power system into six regional entities to which it has delegated authority. One of these regional entities is the WECC, which covers most of the Western United States, including all of the states served by Craig Unit 1.⁴⁰ WECC is a

³⁴ FERC (Office of Public Participation), [Reliability Explainer](#) (last updated Aug. 16, 2023) (last visited Jan. 26, 2026).

³⁵ See *id.*; 16 U.S.C. § 824o(a)(2); N. Am. Elec. Reliab. Corp., 116 FERC ¶ 61,062 (2006), at 3, order on reh’g & compliance, 117 FERC ¶ 61,126 (2006).

³⁶ [Reliability Explainer](#), FERC.

³⁷ 16 U.S.C. § 824o(b)(1).

³⁸ See 18 C.F.R. § 39.11.

³⁹ 18 C.F.R. § 39.8.

⁴⁰ See Fully Executed [Amended And Restated Delegation Agreement Between NAERC And WECC](#) (2021 FERC Revisions - Clean), North American Electric Reliability Corp. (January 1, 2021)

non-profit organization that assures a reliable electric system in the Western Interconnection, a region that covers the Pacific Ocean to the Rocky Mountain states.⁴¹ All of the Craig Unit 1 Owners are members of WECC.⁴²

WECC identifies and registers the Reliability Coordinators and balancing authorities that are responsible for maintaining operating conditions under NERC's reliability standards within its region.⁴³ Reliability Coordinators are the highest level of authority under NERC. They are responsible for the operation of the bulk electric system and have the operating tools, procedures, and authority to prevent or mitigate emergency operating situations.⁴⁴ Balancing authorities ensure that power system demand and supply are balanced, manage transfers of electricity and use economic dispatch to optimize the use of generating units and minimize real-time costs, and maintain operating conditions under NERC reliability standards.⁴⁵ Southwest Power Pool, Inc. ("SPP") is the Reliability Coordinator for Public Service, Tri-State, and PRPA.⁴⁶ WAPA - Rocky Mountain Region Western Area Colorado Missouri ("WACM") is the Balancing Authority for Craig Station.

In addition to this structure, Public Service, PRPA, and Tri-State are now part of the Western Energy Imbalance Market ("WEIS") market, which is a "real-time energy imbalance service market that provides market participants the ability to submit offers to sell and bids to buy imbalance energy, and settles the net supply or

⁴¹ EPA, [U.S. Grid Regions](#) (Nov. 24, 2025).

⁴² WECC, [Membership](#) (2026).

⁴³ Department, [Learning Series: Energy Security & Resilience](#); WECC, [Registration and Certification](#) (2026).

⁴⁴ NERC, [NERCpedia: Reliability Coordinator](#) (2024).

⁴⁵ Department, [Learning Series: Energy Security & Resilience](#).

⁴⁶ SPP, [Western RC Services](#) (2026).

obligation for an asset owner.”⁴⁷ In July of 2025, Public Service was approved to join Markets+, a regional, day-ahead and real-time energy and flexibility reserve product market in the Western Interconnection.⁴⁸ Both WEIS and Markets+ are operated by SPP, but are separate from the RTO that SPP also operates.⁴⁹ And in December 2025, the CoPUC determined that it is in the public interest for Tri-State to join the SPP’s RTO in the Western Interconnection in April of 2026.⁵⁰

The Order states, without support, that the WECC-Northwest Assessment area is experiencing an energy emergency based on NERC’s 2024 Long-Term Reliability Assessment (“2024 LTRA”). But NERC, WECC and its designees have not made a similar determination. The Order merely cites to the 2024 LTRA’s statement that energy variability is greater in the WECC-Northwest area than other regions, and that supply chain issues are a concern.⁵¹ In the 2024 LTRA, the WECC-Northwest Assessment area included Colorado, Idaho, Montana, Oregon, Utah, Washington and Wyoming. However, in NERC’s two more recent assessments, its 2025 Summer Reliability Assessment (“SRA”) and 2025-2026 Winter Reliability Assessment (“WRA”), the WECC-Northwest Assessment area no longer includes Colorado and Wyoming, which were moved to the WECC-Rocky Mountain assessment area, or Utah, which is in the WECC-Basin assessment area.⁵²

⁴⁷ SPP, [Western Energy Imbalance Service \(WEIS\) Quarterly State of the Market](#) (Feb. 13, 2024) at 4.

⁴⁸ CoPUC, Decision No. C25-0697, issued on October 9, 2025, in Proceeding No. 25A-0075E.

⁴⁹ SPP, [About Us](#) (2026).

⁵⁰ CoPUC, Decision No. C25-0906, issued on December 16, 2025, in Proceeding No. 25A-0266E, ¶ 2.

⁵¹ Exhibit K (NERC, [2024 Long-Term Reliability Assessment](#) (Dec. 2024)).

⁵² Exhibit L (NERC, [2025-2026 WRA](#) (Nov. 2025); NERC, [2025 SRA](#) (May 2025)).

In light of this reorganization of the assessment areas, and given the timing of Order, the 2025-2026 WRA is a more relevant assessment for evaluating near-term reliability issues since the WRA specifically covers the upcoming three-month winter period (December-February). This assessment found that “[a]ll assessed areas have adequate resources for normal winter peak load conditions[.]”⁵³ The 2025-2026 WRA found that WECC-Rocky Mountain, the region that includes Colorado and most of Wyoming, would not require reliance on imports to maintain resource adequacy “under combined extreme peak and extreme derated conditions” and that all assessed areas have adequate resources for normal winter peak load conditions.⁵⁴

Thus, the assessments covering the areas served by Craig Unit 1 for both the 90 day term of the Order and beyond do not conclude that there is an energy shortfall or a reliability concern. Yet, the day before Craig Unit 1’s planned retirement, the Department issued a Section 202(c) Order declaring that an emergency exists within the WECC-Northwest assessment area “due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes...”⁵⁵ The Order requires the Craig Unit 1 Owners to ensure that the unit is available to operate for the next 90 days at the direction of WACM in its role as Balancing Authority or the SPP West in its role as Reliability Coordinator.⁵⁶

⁵³ Exhibit L at 5.

⁵⁴ *Id.*, at 38.

⁵⁵ Exhibit A at 1.

⁵⁶ *Id.* at 3-4.

D. The Craig Order is in line with other federal efforts to support the coal industry.

On January 20, 2025, President Trump issued Executive Order 14156, “Declaring a National Energy Emergency.”⁵⁷ That declaration did not provide any factual support for its assertion that the country was in the grips of an electricity emergency. In fact, U.S energy production is at an all-time high and continues to grow.⁵⁸ Although the President recently extended the energy emergency declaration for an additional year, he did not cite any new evidence to justify the supposed emergency.⁵⁹

Setting the stage for the Department’s plan to use Section 202(c) orders to promote the administration’s policy preferences for the nation’s energy mix, on April 14, 2025, President Trump issued Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid.”⁶⁰ This Executive Order directed the Department to streamline and expedite processes for issuing emergency orders under Section 202(c). It also ordered the preparation of a methodology to help identify areas with inadequate reserve margins and directed the use of Section 202(c) orders to prevent certain generation resources from leaving the bulk power system.⁶¹ Pursuant to this Executive Order, the Department published its report titled *Resource*

⁵⁷ Declaring a National Energy Emergency, 90 Fed. Reg. 8433 (Jan. 20, 2025).

⁵⁸ Victoria Zaretskaya, [The United States was the world’s largest liquified natural gas exporter in 2023](#), U.S. Energy Info. Admin.: Today in Energy: In-Brief Analysis (Apr. 1, 2024); U.S. Energy Info. Admin., [U.S. Exports of Crude Oil](#) (last updated Dec. 31, 2025); U.S. Energy Info. Admin., [U.S. Energy Facts Explained: Imports & Exports](#) (last updated July 15, 2024).

⁵⁹ Continuation of the National Emergency With Respect to Energy, 91 Fed. Reg. 1667 (Jan. 12, 2026).

⁶⁰ Exec. Order 14262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521 (Apr. 14, 2025).

⁶¹ 90 Fed. Reg. 15521.

Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (“Resource Adequacy Report” or “Report”),⁶² on July 7, 2025.

Colorado and several other states filed a request for rehearing of the Resource Adequacy Report that pointed out the Report’s many analytical errors, including flawed and unexplained assumptions for load growth projections and resource retirements and additions.⁶³ The Department itself acknowledges in the Report that the agency is not equipped to analyze resource adequacy, stating that its own analysis “could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level.”⁶⁴ Thus, despite issuing a Report intended to guide its use of Section 202(c) authority, the Department does not have the ability to discern whether there is an energy emergency at the regional level.

Nevertheless, the Department proceeded to issue numerous orders under Section 202(c) in 2025 to prevent the retirement of several fossil fuel-fired power plants across the country. In May 2025, the Department issued orders preventing two fossil-fuel generation facilities in Michigan and Pennsylvania from retiring as planned. Both orders failed to identify an imminent energy emergency justifying the units’ continued operation, and instead cited only generalized concerns about resource adequacy.⁶⁵ Both orders have since been reissued multiple times.⁶⁶

⁶² Exhibit M (Department, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (July 2025)).

⁶³ Exhibit N (Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York, filed on August 6, 2025 with the Department).

⁶⁴ Exhibit M, at 2.

⁶⁵ Exhibit O (Department, Order No. 202-25-3 (“Campbell Order”) (May 23, 2025)); Exhibit P (Department, Order 202-25-4 (“Eddystone Order”) (May 30, 2025)).

⁶⁶ See Exhibit I (Department, Order No. 202-25-7 (Aug. 20, 2025) (“Aug. Campbell Extension”)); Exhibit U (Department, Order No. 202-25-9 (Nov. 18, 2025) (“Nov. Campbell Extension”)); Exhibit V

In December 2025, four additional fossil fuel-fired generation facilities were scheduled to retire, and the Department again issued orders requiring their continued availability. In addition to the Craig Order at issue in this proceeding, the Department ordered that units in Washington and Indiana remain available to operate.⁶⁷ Like the Craig Order, the other Section 202(c) orders issued in December also failed to support their emergency determinations with evidence of a specific, imminent energy shortfall or other circumstances that qualify as an emergency under Section 202(c).

IV. Statement Of Issues and Specifications of Error

The State of Colorado submits the following statement of issues and specifications of error:

1. The Order is contrary to law because Section 202(c) only authorizes the Department to respond to specific, imminent, unexpected, and temporary events, while the Order addresses long-term resource adequacy concerns. The statutory text, legislative history, judicial construction, and the Department's regulations all confirm that an emergency must be specific, imminent, unexpected, and temporary. 16 U.S.C. § 824a(c); *Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610 (D.C. Cir. 1978); S. Rep. No. 74 621, 74th Cong., 1st Sess. (1935); 16 U.S.C. § 824a(a) & (b); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232 (8th Cir. 1970).
2. The Order is contrary to law because it exceeds the Department's statutory authority by preventing the long-planned retirement of Craig Unit 1. Section 201(b) of the FPA reserves decisions about plant retirement dates to the states, and Section 202(c) does not vest the Department with general regulatory authority over resource adequacy. By abusing a statute meant only for emergencies, the Order intrudes on authority reserved to states and to other federal regulators to regulate resource adequacy. 16 U.S.C. §824(a); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009); *see also Hughes v. Talen*

(Department, Order No. 202-25-8 (Aug. 28, 2025) ("Aug. Eddystone Extension")); Exhibit PP (Department, Order No. 202-25-10 (Nov. 25, 2025) ("Nov. Eddystone Extension")).

⁶⁷ Exhibit Q (Department, Order No. 202-25-11 (Dec. 16, 2025) ("Centralia Order")); Exhibit S (Department, Order No. 202-25-12 (Dec. 23, 2025) ("Schahfer Order")); Exhibit R (Department, Order No. 202-25-13 (Dec. 23, 2025) ("Culley Order")).

Energy Mktg., LLC, 578 U.S. 150, 155 (2016); *Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004).

3. The Order's determinations are not supported by substantial evidence demonstrating an actual emergency, as indicated by the statutory text and structure and defined in Department regulations, that would necessitate continued operation of Craig Unit 1. The Order fails to exercise reasoned decision making and ignores critical facts, including the findings in its own Resource Adequacy Report, NERC's findings, and state and utility analyses. 16 U.S.C. § 824a(c); *Jarecki v. G.D. Searle & Co.*, 367 U.S. 303 (1961); *Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610 (D.C. Cir. 1978); S. Rep. No. 74-621 (1935); 16 U.S.C. § 824a(a) & (b); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232 (8th Cir. 1970); 16 U.S.C. § 824o;; 10 C.F.R. § 205.371; 10 C.F.R. § 205.375; *Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168(1962).
4. The Order is contrary to law because it fails to present substantial evidence for its emergency determination and ignores critical facts. None of the materials cited in the order provide evidence of an emergency in the WECC-Northwest assessment area or regions served by Craig Unit 1. *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962); *Chritton v. National Transportation Safety Board*, 888 F.2d 854, 856 (D.C. App. 1989); *Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017).
5. The Order is arbitrary and capricious because it fails to require generation that best meets the claimed emergency. 16 U.S.C. § 824a(c)(1); *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009); *Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1 (2020); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); 10 C.F.R. § 205.371;
6. The Order's terms fail to comply with Section 202(c)'s requirements. 16 USC § 824a(c)(1); 16 U.S.C. § 824a(c)(2); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009); see also, e.g., *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 155 (2016).
7. The Order is arbitrary and capricious because it is designed to support the federal administration's policy goal of supporting the coal industry. *Dep't of Commerce v. New York*, 588 U.S. at 782; *Level the Playing Field v. FEC*, 961 F.3d 462, 464 (D.C. Cir. 2020) (quoting *Hagelin v. FEC*, 411 F.3d 237, 242 (D.C. Cir. 2005))

8. The Order violates the National Environmental Policy Act (“NEPA”) because it fails to assess the environmental consequences of a major federal action significantly affecting the human environment. 42 U.S.C. § 4321; *et seq.*; 10 CFR § 1021.103.

V. Request For Rehearing

The Department must grant rehearing and rescind the Order because it suffers from numerous legal and factual deficiencies. Ignoring the legal standards that constrain the exercise of emergency authority under Section 202(c), and acting in disregard of the facts, the Order improperly impinges on state authority over resource planning decisions, imposes unreasonable and unnecessary costs, fails to include required provisions to minimize environmental harms, and advances the administration’s preferred energy source with no reasonable basis. For these reasons, the Order is contrary to law, arbitrary and capricious, and unsupported by substantial evidence. The Department should withdraw it.

- A. **The Order is contrary to law because it improperly expands the use of Section 202(c)’s emergency authority beyond the limited scope set forth in the FPA.**

Section 202(c) authorizes the Department to command action from a utility unconstrained by many of the core procedural safeguards, jurisdictional boundaries, and substantive limitations normally imposed by the FPA.⁶⁸ This power far exceeds the Department’s normal authority, and is therefore restricted to the extraordinary and limited circumstances set forth in the statute.⁶⁹ The FPA’s statutory text and

⁶⁸ See 16 U.S.C. § 824a(c).

⁶⁹ *Id.* (“[d]uring the continuance of any war in which the United States is engaged, or whenever the Commission 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...”).

structure, along with the Department’s regulations, historic practice, and case law interpreting the FPA all make clear that any such event, including a “shortage of electric energy” or the “demand for electric energy” must be one that constitutes a bona fide “emergency”—*i.e.*, a specific, imminent, unexpected and temporary event. The Order exceeds the Department’s authority because those extraordinary and limited circumstances do not exist here, and the Department is instead attempting to use the Order to regulate long term resource adequacy, which is expressly reserved to the states and FERC.

- i. The language, history and structure of Section 202(c) limit the Department to addressing specific, imminent, unexpected and temporary supply shortfalls.*

Section 202(c)’s text authorizes the Department to act only upon an “emergency.”⁷⁰ The statute itself does not define “emergency.”⁷¹ At the time Section 202(c) was enacted, “emergency” was defined as a “sudden or unexpected appearance or occurrence...An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency.”⁷² Contemporary dictionaries likewise define “emergency” as “an unforeseen combination of circumstances or the resulting state that calls for immediate action,” or an “urgent need for assistance or relief.”⁷³

⁷⁰ *Id.*

⁷¹ Although emergency is not defined, the statute does indicate that an emergency includes “the continuance of any war in which the United States is engaged.” 16 U.S.C. § 824a(c)(1).

⁷² *Emergency*, Webster’s New International Dictionary of the English Language (1930).

⁷³ [Emergency](#), Merriam-Webster Dictionary (Jan. 11, 2026); See also Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 812 n.147 (2025) (noting that dictionaries have given the term “emergency” the “same meaning for many years”).

The remainder of Section 202(c)'s plain language also underscores the urgency and immediacy inherent in the word "emergency." The text's use of the present tense underscores its focus on imminent and certain shortfalls, empowering the Department to act only where "an emergency exists."⁷⁴ That near-term focus, along with the fact that this Section 202(c) authority is "temporary" authority,⁷⁵ precludes use of Section 202(c) to pursue long-term policy goals such as preference for a particular fuel source⁷⁶ or interventions to address general concerns about long-term resource adequacy.⁷⁷

The legislative history of the FPA confirms that Congress intended Section 202(c) authority to be used for true emergencies. In a report accompanying the FPA's original passage in 1935, Section 202(c) is described as a "temporary power" to be used in response to "crises:"

This is a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose. Drought and other natural emergencies have created similar crises in certain sections of the country; such conditions should find a Federal agency ready to do all that can be done in order to prevent a break-down in electric supply.⁷⁸

⁷⁴ 16 U.S.C. § 824a(c).

⁷⁵ *Id.*

⁷⁶ *Richmond Power & Light*, 574 F.2d at 615 (Section 202(c) "is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

⁷⁷ See *Coalition for Competitive Electricity, Dynergy Inc. v. Zibelman*, 906 F.3d 41, 50 (2018) (citing 16 U.S.C. § 824(b)) (FPA "leaves to the States alone" the authority "to regulate energy production and facilities used for the generation of electric energy"); see also *Arkansas Elec. Co-op Corp. v. Arkansas Public Service Com'n*, 461 U.S. 375, 377 (1983) ("[T]he regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States.").

⁷⁸ S. Rep. No. 74-621 at 49 (1935).

Section 202's overall structure also highlights Section 202(c)'s emphasis on imminent, near-term concerns. Section 202 established three tiers of federal involvement in grid coordination. Section 202(a)⁷⁹ and Section 202(b)⁸⁰ together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course. Section 202(a) states that the federal government may seek "abundant supply of electric energy" by "divid[ing] the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy." Section 202(b) provides a backstop if the voluntary interconnection and coordination provided for in Section 202(a) fails, allowing the federal government to order "physical connection . . . to sell energy or to exchange energy" upon application, and "after an opportunity for hearing."⁸¹ However, Section 202(b) specifically states that the government has "no authority to compel the enlargement of generating facilities for such purposes."⁸²

The resulting statutory "machinery for the promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection

⁷⁹ 16 U.S.C. § 824a(a).

⁸⁰ 16 U.S.C. § 824a(b).

⁸¹ *Id.*

⁸² *Id.*

of facilities and the generation, delivery, or interchange of energy during times of war or other emergency.”⁸³

This structure relies on voluntary action for everyday energy planning, specifies limited authority where that voluntary system fails, and allows for “temporary” central command-and-control only in case of “emergency.” Section 202(c) authority applies narrowly to immediate and unavoidable “break-down[s] in electric supply,” rather than mere desire for more abundant supply in the future.⁸⁴ Interpreting Section 202(c)’s “emergency” powers to encompass longer-term concerns such as potential shortfall years into the future would unwind the careful balance of voluntary, market-driven action and federal authority set out by Congress. Therefore, such an interpretation cannot be squared with the statutory text, history and structure of Section 202 as required by law.

- ii. Section 215 of the FPA explicitly assigns federal regulation of long term resource adequacy to FERC, further emphasizing that the Department’s Section 202(c) authority is limited to imminent emergencies.*

Section 215 of the FPA, 16 U.S.C. § 824o (“Section 215”), which delineates the scope of federal power to enforce mandatory long-term reliability requirements, confirms that Section 202(c) cannot be used to enforce the Department’s preference for long-term reliability solutions. Congress added Section 215 to the FPA in 2005 precisely because the FPA as it then existed, which included Section 202(c), did not provide the federal government with the power to enforce measures designed to

⁸³ S. Rep. No. 74-621 at 49 (1935).

⁸⁴ *Id.*

ensure broad, long-term reliability.⁸⁵ Implementation of Section 215, including the approval and enforcement of reliability standards for all entities operating in the bulk power system, is left to FERC and its designated ERO, not the Department.⁸⁶

By enacting Section 215, Congress newly created a comprehensive and carefully circumscribed scheme to allow FERC—not the Department—to address long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent “of the users and owners and operators of the bulk-power system” but with “fair stakeholder representation.”⁸⁷ FERC may approve or remand those standards (but not replace them with its own) and must “give due weight” to NERC’s “technical expertise” while independently assessing effects on “competition.”⁸⁸ Section 215 specifies enforcement mechanisms and procedures for reliability standards and carefully preserves state authority over “the construction of additional generation” and

⁸⁵ See Rules Concerning Certification of the ERO; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards, 70 Fed. Reg. 53,117, 53,118 (Sept. 7, 2005) (“In 2001, President Bush proposed making Electric Reliability Standards mandatory and enforceable[.]” leading to enactment of Section 215 in 2005); National Energy Policy Development Group, *Reliable, Affordable, and Environmentally Sound Energy for America's Future* (May 2001) at 7-6 (noting that “[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country” and that “[o]ne factor limiting reliability is the lack of enforceable reliability standards” because “the reliability of the U.S. transmission grid has depended entirely on voluntary compliance,” and then recommending “legislation providing for enforcement” of reliability standards) (emphasis added); S. Rep. No. 109-78, 109th Cong., 1st Sess. at 48, Section 1211 (2005) (Section 215 “changes our current voluntary rules system to a mandatory rules system” for long-term reliability); see *Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, “the reliability of the nation’s bulk-power system depended on participants’ voluntary compliance with industry standards”).

⁸⁶ 16 U.S.C. § 824o.

⁸⁷ 16 U.S.C. § 824o(c)(2)(A); see also *id.* § 824o(a)(3) (defining reliability standards as “a requirement ... to provide for reliable operation of the bulk-power system”).

⁸⁸ *Id.* § 824o(d)(2)-(4).

regulation of in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards.⁸⁹

Interpreting Section 202(c) to permit the Department to mandate generation based on its determination that non-imminent and unsubstantiated reliability concerns create an “emergency” would effectively allow the Department to bypass Section 215’s procedural safeguards, constraints on federal authority, and protection of state power over long-term reliability. This would impermissibly contradict Congress’ clear intent as expressed in its more recent reliability-specific provisions, enacted with the understanding that the Department had no authority to address long-term reliability through Section 202(c).⁹⁰ “Congress’s specific and limited enumeration of [agency] power” over a particular matter in one section of the FPA “is strong evidence that [a separate section] confers no such authority on [an agency].”⁹¹ Congress has, in Section 215, directly established the mechanisms by which the federal government may compel action to ensure long-term electric-system reliability, and that authority does not rest with the Department. In so doing, Congress has confirmed that the word “emergency,” as used in Section 202(c), does not extend to long-term reliability concerns and only applies to specific, imminent, unexpected and temporary events.

⁸⁹ *Id.* §§ 824o(e), -(i)-(j).

⁹⁰ See also *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 121 (2000) (“The meaning of one statute may be affected by other Acts, particularly where Congress has spoken subsequently and more specifically to the topic at hand.”).

⁹¹ *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401 (D.C. Cir. 2004).

iii. The Order is arbitrary, capricious and contrary to law because it contradicts the Department's regulations interpreting Section 202(c) and its historic practice in applying Section 202(c).

The Department's regulations confirm that Section 202(c)'s authority is confined to imminent and unexpected resource shortages rather than long-term reliability concerns. Those regulations define "emergency" for the purposes of Section 202(c) to mean circumstances that arise suddenly and unexpectedly:

"Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities.⁹²

This focus on specific events like weather conditions, acts of God, or unforeseen circumstances outside of the power of the affected entity to prevent, along with the reference to a "sudden increase in customer demand" producing a "specific inadequate power supply situation,"⁹³ foreclose the Department from using 202(c) authority to address vague long-term supply and reliability issues, such as those articulated in the Order.

This need for specificity is repeated in the Department's regulations defining an inadequate energy supply: "[a] system may be considered to have inadequate" supply when "the projected energy deficiency...will cause the applicant [for a 202(c)

⁹² 10 C.F.R. § 205.371.

⁹³ *Id.*

Order] to be unable to meet its normal peak load requirements based upon use of all of its otherwise available resources so that it is unable to supply adequate electric service to its ultimate customers.”⁹⁴ An emergency may exist where past planning failures produce an immediate, present-tense shortfall, but the Department has no authority to commandeer long-term planning merely because it deems current plans inadequate to meet long-term needs.⁹⁵ As the Department stated when it promulgated these regulations, the statute allows the Department to provide “assistance [to a utility] during a period of unexpected inadequate supply of electricity,” but does not empower it to “solve long-term problems.”⁹⁶

Until 2025, the Department’s orders complied with this regulatory scheme and the agency used its Section 202(c) authority only in response to concrete, particularized emergencies, subject to narrow, appropriate limitations. Established “practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.”⁹⁷ Until recently, the Department has used Section 202(c) to address specific, imminent, and unexpected shortages, never to address longer-term reliability concerns or demand forecasts.⁹⁸ As pointed out by the Congressional

⁹⁴ 10 C.F.R. § 205.375.

⁹⁵ See *id.* (requiring present inability to meet demand to demonstrate inadequate energy supply).

⁹⁶ Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984, 39,985-86 (Aug. 6, 1981).

⁹⁷ See *FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941).

⁹⁸ See, e.g., Department, [Order No. 202-22-4](#) (Dec. 24, 2022) at 1 (responding to ongoing severe winter storm producing immediate and “unusually high peak load” between December 23 and December 26); Department, [Order No. 202-20-2](#) (Sept. 6, 2020) (responding to shortages produced by ongoing extreme heat and wildfires); see also Rolsma, 57 Conn. L. Rev. at 803-4 (describing “sparing[]” use of Section 202(c) outside of wartime shortages during the twentieth century).

Research Service, the orders issued by the Department in May 2025 (and subsequently renewed) to keep coal plants open “all involve[d] seemingly new interpretations of the emergency authority.”⁹⁹ The Order at issue in this proceeding continues this improper use of Section 202(c).

Similarly, before 2025, the Department used Section 202(c) on only three occasions to delay the retirement of generation facilities.¹⁰⁰ Each case met the following four criteria: (1) the order was requested by a system operator or governmental body; (2) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (3) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and (4) the Department tailored its order to go no further than necessary to address the emergency.

⁹⁹ Cong. Research Serv., *Federal Power Act: The Department of Energy’s Emergency Authority*, CRS Report No. R48568, at 3 (June 12, 2025).

¹⁰⁰ In 2005, the Department issued an order directing the continued operation of a facility in Alexandria, VA, after the facility was abruptly closed based on noncompliance with its air permit. The order only applied when one or both of the 230 kv transmission lines serving downtown D.C. were out of service. Department, [Order No. 202-05-3](#) (Dec. 20, 2005). In 2017, an Oklahoma state agency asked the Department to direct the continued operation of a unit that would otherwise close because the unit was needed to provide dynamic reactive power support to the local grid, as confirmed by its reliability coordinator. The unit was needed because another unit at the station had been struck by lightning, and the third unit’s construction had been delayed due to flooding delaying essential project materials. The Department subsequently ordered the unit to remain in operation for 90 days or until one of the other two units came online, to provide dynamic reactive power support when called upon by its reliability coordinator. Department, [Order No. 202-17-1](#) (Apr. 14, 2017). Finally, in 2017, two Virginia utilities asked the Department to direct the continued operation of two units of a power station because they were necessary to prevent uncontrolled power disruptions and shedding of critical load. [Letter from PJM Interconnection, LLC, to the Department](#) (Aug. 24, 2017).

The Department's unexplained deviation from its prior interpretation of the statute, as demonstrated through its past practice, is unlawful, arbitrary and capricious.¹⁰¹ And the Department cannot deviate from its regulations without conducting new notice and comment rulemaking and providing a reasonable basis for any change.¹⁰² A cornerstone of administrative law is "that an agency must provide[] a reasoned explanation for departing from precedent or treating similar situations differently."¹⁰³ For this reason, "an interpretation of a legislative rule cannot be modified without the notice and comment procedure that would be required to change the underlying regulation—otherwise, an agency could easily evade notice and comment requirements by amending a rule under the guise of reinterpreting it."¹⁰⁴ The Department has not undertaken any such notice and comment procedure here and has not provided any reasoned justification for its recent departure from the binding requirements and interpretations of its governing statute and regulations.

iv. Courts have found that the Department's use of Section 202(c) is limited to true emergencies and the Department is bound by the courts' statutory interpretation.

There is little case law on Section 202(c). However, two decisions that have addressed the Department's authority under Section 202(c) both recognize that the

¹⁰¹ *F.C.C. v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009) ("To be sure, the requirement that an agency provide reasoned explanation for its action would ordinarily demand that it display awareness that it *is* changing position.").

¹⁰² See 5 U.S.C. § 553; *F.C.C.*, 566 U.S. at 515 (holding that an agency cannot simply change position on an issue without "a reasoned explanation" and "awareness that it is changing position.").

¹⁰³ *New England Power Generators Ass., Inc. v. FERC*, 881 F.3d 202, 210-12 (D.C. Cir. 2018) (quoting *W. Deptford Energy, LLC v. FERC*, 766 F.3d 10, 20 (D.C. Cir. 2014)).

¹⁰⁴ *Env't Integrity Project v. EPA*, 425 F.3d 992, 995 (D.C. Cir. 2005) (internal citations omitted); see also *Center for Biological Diversity v. Haaland*, 998 F.3d 1061, 1067 (9th Cir. 2021) (internal citations omitted) ("When an agency changes its position, it must: (1) "display [] awareness that it is changing position," (2) "show "the new policy is permissible under the statute," (3) "believe[]" the new policy is better, and (4) provide "good reasons" for the new policy.").

Department's power under Section 202(c) is limited to specific, imminent, unexpected and temporary events.

First, during the 1973 oil embargo, the Federal Power Commission called for a voluntary transfer of electricity from non-oil power plants to areas of the country that relied heavily on oil, but the New England Power Pool petitioned for a Section 202(c) order because it was not convinced the voluntary program would work.¹⁰⁵ The Commission declined to issue a Section 202(c) order, and instead facilitated an agreement between state commissions and supplying utilities.¹⁰⁶ In *Richmond Power and Light of City of Richmond, Indiana v. FERC*, the D.C. Circuit upheld the Commission's decision to not invoke Section 202(c).¹⁰⁷ The utility argued that the country's dependence on foreign oil, and the high cost and uncertain supply of foreign oil, left the country with a continuing emergency, but the court agreed with the Commission's argument that the facilitated agreement had worked, service was never interrupted, and there was no need for a Section 202(c) order.¹⁰⁸ The court highlighted that the statute "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply[.]"¹⁰⁹ The court upheld the Commission's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor."¹¹⁰

¹⁰⁵ *Richmond Power & Light*, 574 F.2d at 613.

¹⁰⁶ *Id.*

¹⁰⁷ *Id.* at 614.

¹⁰⁸ *Id.* at 615.

¹⁰⁹ *Id.*

¹¹⁰ *Id.*

The Eighth Circuit Court of Appeals has also held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Fed. Power Comm'n.*, a utility insisted a Section 202(c) order was necessary to properly order the utility to connect to a municipal power provider. The demand for electricity in the city had increased, and the peak load of the municipal power provider was high enough that both of its two generators would likely be needed simultaneously in the near future, which could cause a possible loss of service if one of them malfunctioned during a peak period.¹¹¹ Instead of issuing a 202(c) order, the Commission issued an order under Section 202(b), which the utility argued was incorrect.¹¹²

In upholding the Commission's decision, the court distinguished between an emergency that is likely to occur and one that is actually occurring, concluding that Section 202(b) applies to the former, while Section 202(c) applies to the latter:

On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.¹¹³

Therefore, the court agreed that a potential crisis in the foreseeable future was not an emergency, making this current situation "just the type of situation to fit into a § 202(b) hearing rather than § 202(c)." ¹¹⁴

¹¹¹ *Otter Tail Power*, 429 F.2d at 233-234.

¹¹² *Id.*

¹¹³ *Id.* at 234.

¹¹⁴ *Id.*

Because courts, not agencies, decide “all relevant questions of law” arising on review of agency actions, the Department is bound by these courts’ “best reading” of the statutory language.¹¹⁵

B. Section 202(c) does not vest the Department with general regulatory authority over resource adequacy, which is regulated by the states and FERC under other provisions of the FPA.

The FPA preserves states’ authority over generation facilities and resource adequacy planning, and Section 202(c) does not vest the Department with general regulatory authority over resource adequacy. Under the FPA, states are responsible for their own resource adequacy and decisions about generation facilities, and FERC is responsible for assuring the reliability of the nation’s bulk power system. Because there is no imminent shortfall or other circumstance constituting an emergency, the Order is an illegal attempt to regulate long term resource adequacy by misusing the Department’s Section 202(c) authority.

i. The FPA grants authority over generation and resource adequacy to the states.

The structure and language of the FPA reflect Congress’ deliberate choice to preserve the states’ traditional authority over generating facilities and to limit the Department’s emergency authority. The FPA states that “the Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy...”¹¹⁶ Congress also recognized the states’ exclusive authority over generating

¹¹⁵ *Loper Bright Enterprises v. Raimondo*, 603 U.S. 369, 392, 399-400 (2024).

¹¹⁶ 16 U.S.C. § 824(b)(1).

facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes."¹¹⁷ FERC's role in regulating electricity generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States."¹¹⁸

Pursuant to the FPA, "[t]he states are thus authorized to regulate energy production . . . and facilities used for the generation of electric energy."¹¹⁹ Decisions around what facilities to build, whether they remain feasible, and retail rates are areas governed by the states.¹²⁰ Courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities, including that states retain the right "to require the retirement of existing generators" or to take any other action in their "role as regulators of generation facilities."¹²¹ FERC has acknowledged that "[r]esource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsive for procuring adequate capacity to serve loads within their respective jurisdictions."¹²²

The electric power sector is governed by longstanding principles of cooperative federalism encouraged in Section 209(b) of the FPA, which explicitly declares that FERC may consult with states "regarding the relationship between rate structures,

¹¹⁷ 16 U.S.C. § 824a(b).

¹¹⁸ 16 U.S.C. § 824(a).

¹¹⁹ *Coal. for Competitive Elec.*, 906 F.3d at 50.

¹²⁰ *Pac. Gas & Elec. Co. v. State Energy Res. Conservation and Dev. Comm'n*, 461 U.S. 190, 205 (1983).

¹²¹ *Conn. Dep't of Pub. Util.*, 569 F.3d at 481; see also *Hughes*, 578 U.S. at 155.

¹²² *Devon Power LLC, et al.*, 109 FERC ¶ 61,154, P 47 (2004).

costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission.”¹²³ FERC has embraced these cooperative federalism principles and developed long-standing consultation practices with the states, including through creation of a Joint Federal-State Task Force,¹²⁴ and more recently, a Federal-State Current Issues Collaborative which was formed due to the success of the Task Force.¹²⁵ The importance of this cooperation is evident in the Department’s own Resource Adequacy Report, which flagged that it could have benefitted greatly from cooperation with the states due to the “in-depth engineering assessments which occur at the regional and utility level.”¹²⁶

In the Order, the Department seeks to substitute its own judgment about which resources should be employed to maintain resource adequacy for the states’ decisions, despite these decisions resting firmly in the jurisdiction of the states. Section 202(c) does not provide the Department with the authority to mandate that resources remain running to address long-term resource adequacy. If Congress intended to vest regulatory authority over long-term resource adequacy in Section 202(c) and displace state law, it would have needed to make that intent “unmistakably clear.”¹²⁷ Section 202(c) says that the Department may “require by

¹²³ 16 U.S.C. § 824h(b).

¹²⁴ FERC, [Joint Federal-State Task Force on Electric Transmission](#) (Sept. 3, 2025).

¹²⁵ FERC, [Federal-State Current Issues Collaborative](#) (Jan. 21, 2026).

¹²⁶ Department, [Resource Adequacy Report Evaluating the Reliability and Security of the United States Electric Grid](#) (July 2025) at 2.

¹²⁷ *Gregory v. Ashcroft*, 501 U.S. 452, 460 (1991) (The clear statement rule requires Congress to make its intent unmistakably clear if it intends a statute to alter the usual constitutional balance between the federal government and the states.); *see also DeMarco v. Holy Cross High Sch.*, 4 F.3d 166, 169 (2d Cir. 1993) (Congress must express an affirmative intention to use a statute to alter the federal balance.).

order . . . such generation . . . of electric energy as in its judgment will best meet the emergency and serve the public interest.”¹²⁸ Empowering the Department to generally determine which power plants may retire across every utility and independent power producer across the entire country would have profound implications for rates, state sovereignty, and a broad array of other state policy and stakeholder interests. If Congress had intended to do that, it would not have done so through the only provision in the FPA that empowers the Department to act outside normal procedural safeguards.

The Supreme Court has rejected statutory interpretations where an agency “claim[s] to discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority.”¹²⁹ The Department may not radically reinterpret a 90-year-old statute to manufacture a basis to exercise much broader authority than it ever has in the past. Previous exercises of Section 202(c) authority have been at the request of a system operator or governmental body and in a manner narrowly tailored to respond to a concrete and particularized emergency. Prior to the current administration, the Department has never issued a Section 202(c) order to impose its policy preferences to contravene the judgment of those bodies properly responsible for ensuring resource adequacy, *i.e.*, the states and FERC. For these reasons, the Order should be withdrawn.

¹²⁸ 16 U.S.C. § 824a(c)(1).

¹²⁹ *W. Virginia v. EPA*, 597 U.S. 697, 724, (2022) (quoting *Util. Air. Regul. Grp. V. E.P.A.*, 573 U.S. 302, 324 (2014)) (internal quotations omitted).

- ii. *The Order improperly infringes on authority granted to states and FERC under the FPA by attempting to regulate long-term resource adequacy and generation.*

The Department is attempting to regulate long term resource adequacy and energy production under the guise of a Section 202(c) emergency, and is therefore intruding on the FERC and state authority discussed above.

It is clear from the Order, the Department's Resource Adequacy Report, and statements by President Trump, and the Department, that the Department is using its Section 202(c) authority for circumstances beyond actual emergencies. The Order repeatedly references long term reliability. For example, the Department's determination that an emergency exists rests on the assertion of a long term concern that "increasing demand and shortage from accelerated retirement of generation facilities . . . could lead to the loss of power to homes, and businesses" that are "likely to continue in subsequent years."¹³⁰ The Order also cites the LTRA's statement regarding resource retirements between now and 2028, that WECC's Northwest-Central subregion will have demand growth over the next decade, and that Colorado will have a certain amount of coal-fired generating capacity retired by 2029.¹³¹ Demand growth and retirements occurring over the next decade fall into the realm of long term resource planning, not an imminent Section 202(c) emergency, which must be unexpected, sudden, and temporary.¹³²

¹³⁰ Exhibit A at 3.

¹³¹ *Id.*, at 2.

¹³² Section V.A, *supra*.

Both the Department and President Trump have publicly acknowledged that their goal is to regulate long term resource adequacy and mandate coal generation. the Department Secretary Wright has stated that “[t]he goal [of the recent 202(c) orders] is to stop the political closure of coal plants.”¹³³ The “Clean Beautiful Coal” Executive Order directed the Department to “identify regions where coal-powered infrastructure is available and suitable for supporting AI Data centers; assess the market, legal and technological potential for expanding coal-based infrastructure to power data centers to meet the electricity needs of AI...”¹³⁴ These statements demonstrate a clear intention to use coal plants to meet long term resource adequacy needs, which exceeds the Department’s Section 202(c) emergency authority.

C. The Order fails to present substantial evidence for its emergency determination and ignores critical facts.

Agencies “must examine the relevant data and articulate a satisfactory explanation for [their] actions, including a rational connection between the facts found and the choice made[,]” and make findings that are supported by substantial evidence.¹³⁵ Substantial evidence is “such relevant evidence as a reasonable mind might accept as adequate to support a conclusion.”¹³⁶ Similarly, orders under the FPA must reflect “a principled and reasoned decision supported by the evidentiary record.”¹³⁷ Here, the Department failed to provide evidence of an imminent resource

¹³³ Department, [Energy Department Convenes First National Coal Council Meeting Under Renewed Charter, Reaffirming Coal’s Role in Unleashing American Energy](#) (Jan. 15, 2026).

¹³⁴ [Exec. Order No. 14241](#), 90 Fed. Reg. 15,517 (Apr. 14, 2025).

¹³⁵ *Motor Vehicle Mfrs. Ass’n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)).

¹³⁶ *Chritton*, 888 F.2d at 856 (quoting *Refrigerated Transport Co., Inc. v. I.C.C.*, 616 F.2d 748, 751 (5th Cir.1980) (quoting *Chem-Haulers, Inc. v. United States*, 536 F.2d 610, 617 (5th Cir.1976)).

¹³⁷ *Emera Maine*, 854 F.3d at 22.

adequacy shortfall, making the Order contrary to law. The purported evidence of an emergency the Order cites is: the 2024 LTRA, WECC's Western Assessment of Resource Adequacy, and the Department's Resource Adequacy Report; general load growth in the WECC-Northwest region and generation retirement in Colorado; the Grid Reliability and Energy Emergency Executive Orders; and data center load growth. Contrary to the Order's claims, these reports and observations do not provide sufficient evidence of an energy emergency in the WECC-Northwest region or the areas served by Craig Unit 1.

- i. NERC's assessments do not establish that there is an energy emergency in the areas served by Craig Unit 1.*

The Order cites the NERC 2024 LTRA's statement that energy variability is greater in the Northwest than other regions, and that the WECC-Northwest assessment area anticipates baseload resource retirements to be primarily replaced by solar, wind, and battery, which increases variability and implicates some supply chain concerns.¹³⁸ The Order relies on these statements to assert the WECC-Northwest assessment area is experiencing an energy emergency. This both mischaracterizes the 2024 LTRA's conclusions and ignores more relevant and recent NERC assessments. By failing to consider relevant facts and to support its findings with substantial evidence, the Department's Order is contrary to law.

The Department's choice to rely on the 2024 LTRA as evidence of an emergency is fundamentally flawed. NERC serves an important advisory role by providing recommendations about risks to the grid, but ultimately, determinations

¹³⁸ Exhibit A.

about generation resources remain within state authority.¹³⁹ Importantly, NERC's reports do not examine regions at the level of granularity that would be required to determine whether a particular resource is essential for regional resource adequacy. The reports only provide the anticipated planning reserve margins of large regions as a whole. The purpose of NERC assessments are to identify for grid operators constraints that might arise and implicate grid reliability if not mitigated.¹⁴⁰ Thus, even regions designated as at risk are not necessarily grid emergencies, they are merely periods of time during which the relevant grid operators must take mitigation measures to maintain grid security, under their set procedures. In addition, the 2024 LTRA was published more than a year ago and relies on data almost two years old. It assesses the adequacy of planned resources to meet electricity demand across North America over the next ten years.¹⁴¹ The 2024 LTRA does not address short-term reliability issues. Therefore, this report cannot support a decision by the Department to keep one power plant open in the name of a general region-wide emergency.

Even if it was an appropriate assessment for the Department to rely upon, the 2024 LTRA does not actually demonstrate an emergency for the WECC-Northwest assessment area, contrary to the Order's claims. The Order cherry picks certain information from the 2024 LTRA: citing its statement that the WECC-Northwest assessment area anticipates retiring 5 Gigawatt ("GW") of baseload resource retirements between 2024 and 2028, which will be replaced by solar, wind, and

¹³⁹ NERC, [Reliability Assessments](#) (2026).

¹⁴⁰ Exhibit L.

¹⁴¹ Exhibit K.

batteries, and that supply chain issues preventing the construction of battery systems are a concern. The Order conveniently ignores the 2024 LTRA's entire analysis of the WECC-Northwest assessment area's forecasted resource adequacy, and its calculation that the WECC-Northwest has anticipated reserve margins (when including announced generation retirements) of 38.9% for 2026, 35.6% for 2027, and 30.7% for 2028.¹⁴² The 2024 LTRA found that the WECC-Northwest region has "negligible unserved energy and load-loss risk."¹⁴³

Although the 2024 LTRA identified a potential shortfall starting in summer 2029, this potential shortfall was projected only if new resources planned in the region were "significantly delayed," in which case "imports may be necessary."¹⁴⁴ A potential shortfall starting over three years from now—and only if planned resources are significantly delayed—does not provide sufficient evidence to support an emergency declaration for the 90 days covered by the Order. And even if "significant delays" create risk in summer 2029, the 2024 LTRA suggests that imported power will be sufficient to cover any shortfall, once again undermining any case for mandating continued operation of a single generating unit.

The 2024 LTRA also found that the WECC-Southwest region, which includes Arizona, has anticipated reserve margins (when including announced generation retirements) of 35.6% for 2026 and 31.6% for 2027.¹⁴⁵ The WECC-Southwest region does not show any shortfall of existing certain and net firm transfers until 2028, when

¹⁴² *Id.*, at 20.

¹⁴³ *Id.*, at 129.

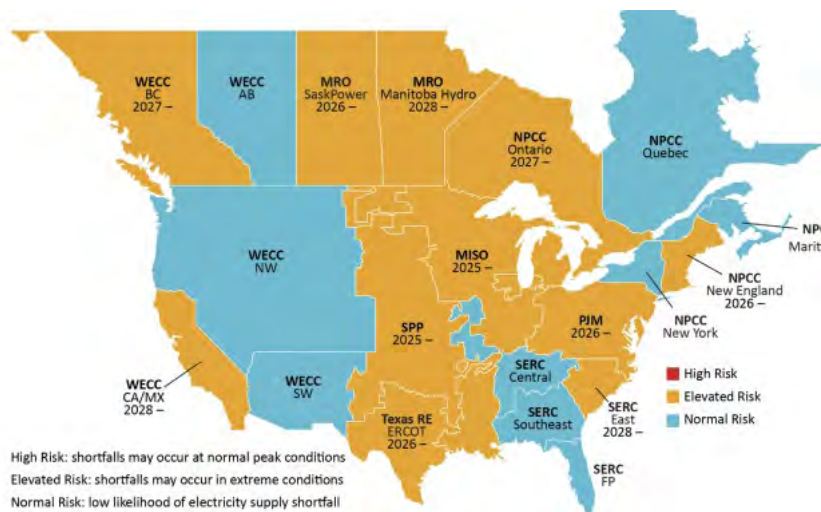
¹⁴⁴ *Id.*

¹⁴⁵ *Id.*, at 20.

imports may become necessary, but only if new resources were significantly delayed.¹⁴⁶

As shown in the figure below, WECC-Northwest and WECC-Southwest, which covers all the states served by Craig Unit 1, are designated as normal risk, which means a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low.¹⁴⁷

Figure 1: 2024 LTRA Risk Area Summary 2025-2029¹⁴⁸



Next, the Order completely fails to acknowledge the two more recent short-term reliability assessments, the 2025-2026 WRA and the 2025 SRA, which evaluate overall operating reliability for the assessed regions on a seasonal basis and account for near-term resource availability impacts such as outages on the peak operating periods for the summer and winter.¹⁴⁹ The 2025-2026 WRA is NERC's most recently

¹⁴⁶ *Id.*, at 132.

¹⁴⁷ *Id.*, at 6.

¹⁴⁸ *Id.*, at 6.

¹⁴⁹ NERC, [ERO Enterprise Reliability Assessment Process Document](#) (Jan. 2024).

published report and covers the current three-month winter period (December 2025-February 2026)—approximately the same time period covered by the Order. It evaluates the generation resource and transmission system adequacy necessary to meet projected demands and operating reserves and identifies potential reliability issues of interest and regional risk.

The Department’s reliance on the 2024 LTRA is also problematic because NERC changed the geographic scope assessment areas for the 2025 SRA and 2025-2026 WRA. The 2024 LTRA includes Colorado, Utah, and Wyoming in the WECC-Northwest assessment area, and Arizona is in the WECC-Southwest assessment area.¹⁵⁰ Since the Order is issued to Craig Unit 1 in Colorado, and only references the LTRA and the WECC-Northwest area, it appears the Order is relying on the 2024 LTRA’s scope of the WECC-Northwest area. Importantly, the 2025 SRA and 2025-2026 WRA do not include any of the states served by Craig Unit 1 in the WECC-Northwest. For these assessments, the WECC-Rocky Mountain area, not the WECC-Northwest area, includes Colorado and most of Wyoming, WECC-Southwest includes Arizona, and WECC-Basin includes Utah and the rest of Wyoming.¹⁵¹ The Order ignores that NERC changed the assessment areas used in the 2024 LTRA to “more accurately reflect operational and planning realities, as well as the footprints of various entities[,]”¹⁵² and instead refers to the outdated regions used in the 2024 LTRA. The Department should reconsider the

¹⁵⁰ Exhibit K at 127, 131.

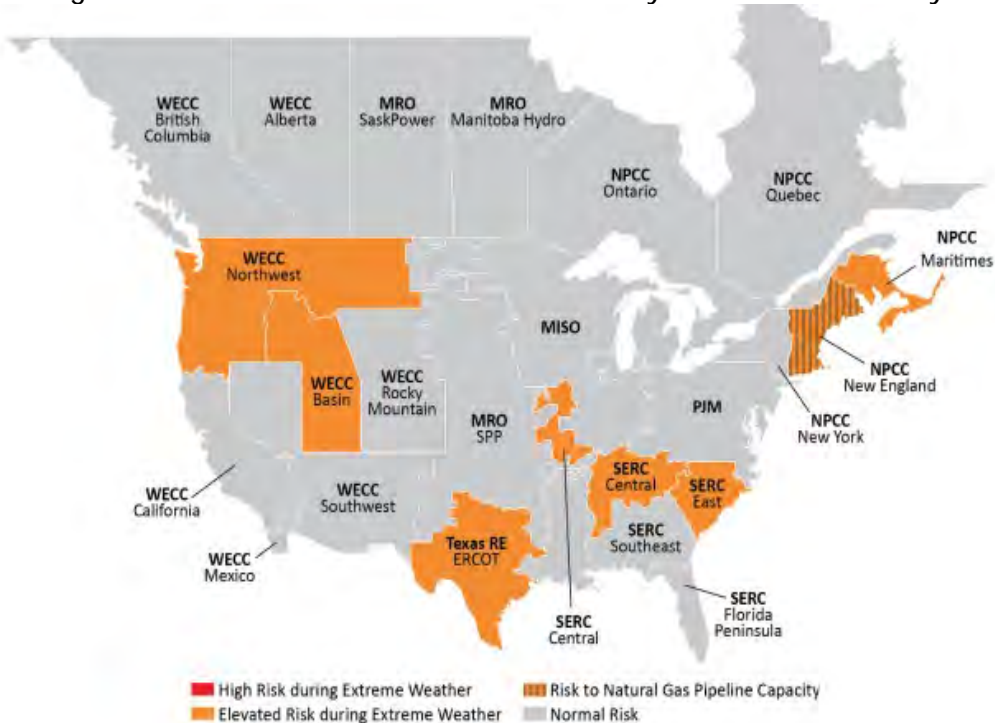
¹⁵¹ NERC, [2025 SRA](#) (May 2025), at 36.

¹⁵² WECC, [2025-2026 WRA Western Overview](#).

Order because the scope of the declared emergency does not match the assessment area.¹⁵³

The 2025-2026 WRA found that “all assessed areas have adequate resources for normal winter peak load conditions.”¹⁵⁴ WECC-Rocky Mountain, which includes Colorado and most of Wyoming, and WECC-Southwest, which includes Arizona, were not found to be at risk of electricity supply shortfalls even in more extreme winter conditions extending over a wide area.¹⁵⁵

Figure 2: 2025-2026 WRA Winter Reliability Risk Area Summary¹⁵⁶



¹⁵³ The mismatch between the assessment area and the scope of the purported emergency will also complicate operations and cost recovery actions. Because Craig Unit 1 does not serve the majority of states in the WECC-Northwest assessment area, it is unclear how Craig Unit 1 could be operated to meet an emergency in that area, and unclear which ratepayers should be responsible for the costs of any such operations. Colorado does not concede that Colorado ratepayers should be responsible for these costs.

¹⁵⁴ Exhibit L at 5.

¹⁵⁵ *Id.*, at 5.

¹⁵⁶ *Id.*, at 6.

According to the 2025-2026 WRA, the WECC-Rocky Mountain area will **not** need to rely on imports to maintain resource adequacy even under combined extreme peak and extreme derated conditions, and operating reserve margins are expected to be met before needing imports in all winter scenarios.¹⁵⁷ The region has an anticipated total internal demand of 11,501 MW, and 17,768 MW of certain capacity, which does not include planned capacity and anticipated resources.¹⁵⁸ This leaves an anticipated reserve margin of a staggering 61.7%, which is over triple the reference margin level of 18.2%.¹⁵⁹ By contrast, Craig Unit 1 could provide a maximum of 222 MW to the WECC-Rocky Mountain area, which would have a negligible impact on the already high anticipated reserve margin.

The 2025-2026 WRA also expects WECC-Southwest to be resource adequate under all winter expected and extreme energy availability and demand scenarios before needing imports.¹⁶⁰ WECC-Southwest has a total demand of 21,147 MW and a certain capacity of 40,135 MW before accounting for planned capacity and anticipated resources.¹⁶¹ This leaves an anticipated reserve margin of 104.4%.¹⁶²

WECC-Basin (which includes Utah, where PacifiCorp owns a mere 19% of Craig Unit 1, or 82 MW of the unit's total capacity) has sufficient capacity for expected peak conditions and an anticipated reserve margin of 29.6% for this season.¹⁶³ This means that expected resources meet operating reserve requirements under normal

¹⁵⁷ *Id.*, at 38.

¹⁵⁸ *Id.*, at 49.

¹⁵⁹ *Id.*

¹⁶⁰ *Id.*, at 39.

¹⁶¹ *Id.*, at 49.

¹⁶² *Id.*

¹⁶³ *Id.*, at 6, 48.

peak demand scenarios. The WECC-Basin region is designated as “elevated risk” in the 2025-2026 WRA because it would require external assistance only during a combination of above normal peak demand and high generator outages in extreme conditions.¹⁶⁴ However, a designation of “elevated risk” does not constitute an imminent emergency. Rather, the WRA concludes that “the results of the probabilistic assessment reveal no [Expected Unserved Energy] or [Loss of Load Hours] for Winter 2025- 2026.”¹⁶⁵

Consistent with this assessment, none of the Craig Unit 1 Owners has indicated that they need Craig Unit 1 to mitigate any resource adequacy concerns this winter. None of the NERC assessments, whether cited by the Order or not, provide substantial evidence of an energy emergency in the WECC-Northwest region.

ii. WECC’s Western Assessment of Resource Adequacy and the Department’s Resource Adequacy Report do not demonstrate an emergency.

The Order also cites the 2024 WECC Western Assessment of Resource Adequacy (“2024 WECC Assessment”) to support its declaration of an emergency. Like the 2024 LTRA that the Order cites, the 2024 WECC Assessment does not analyze near-term resource adequacy, and instead uses a probabilistic approach to evaluate reliability over the next ten years.¹⁶⁶ This makes the 2024 WECC Assessment inappropriate for providing evidence of an emergency under Section 202(c).

¹⁶⁴ *Id.*, at 6.

¹⁶⁵ *Id.*, Table 5: Probability-Based Risk Assessment, at 14 (emphasis added).

¹⁶⁶ WARA, [Western Assessment of Resource Adequacy 2024](#).

Even if the 2024 WECC Assessment was appropriate evidence for the Department to rely upon, it does not demonstrate an emergency in the areas served by Craig Unit 1. Once again, the Department selectively cites information in that report showing that peak demand is expected to grow and that there are planned baseload generation retirements, but ignores that this assessment finds no near-term energy emergency in any of WECC's regions.¹⁶⁷ In fact, the 2024 WECC Assessment finds that entities in the Western Interconnection plan to add more than 172 GW of new generation capacity in the next ten years, while a mere 25.85 GW of generation is planned to retire over the same period.¹⁶⁸ WECC's Northwest-Central subregion, which includes Colorado, whose load growth the Order specifically mentions, does not have demand at risk hours until 2031, and then only in a scenario where merely 55% of planned additions are completed and operational on time.¹⁶⁹ The 2024 WECC Assessment does not provide substantial evidence of an emergency in the areas served by Craig Unit 1.

Next, the Order briefly references the Department's Resource Adequacy Report,¹⁷⁰ which purports to provide a uniform methodology for identifying at-risk regions and grid reliability issues and guide reliability interventions. As with other reports cited in the Order, this Report provides no support for the Department's determination that there is an emergency requiring continued availability of Craig Unit 1 in the next 90 days, or even the next year. The Report assesses the ability of

¹⁶⁷ Exhibit A, at 2.

¹⁶⁸ WARA, [Western Assessment of Resource Adequacy 2024](#).

¹⁶⁹ *Id.*

¹⁷⁰ Exhibit M.

the electric grid to “meet *future* demand through 2030” and is a “*forward-looking* snapshot of resource adequacy.”¹⁷¹ This Report was not designed to assess imminent emergency conditions of the electric grid, and explicitly does not do so.

Indeed, the Report’s only conclusions are for 2030, which is completely irrelevant for an emergency Section 202(c) order issued in 2025. The Report finds potential reliability issues in 2030 only under a set of unsupported assumptions that assume unrealistically high load projections stemming from unfounded assumptions about data center load, and assume that utilities virtually cease construction of new generation and transmission resources. Its 2030 projections are at odds with the analyses from NERC and WECC, as well as the findings from Colorado’s ERP proceedings and resource adequacy reporting. In any case, a claimed reliability issue in 2030 can not justify a 90 day emergency order in 2026. Forcing ratepayers to pay to keep generation online that is not needed, simply because technology companies may be building more data centers in the future that may need power is arbitrary and violates the FPA’s requirement that rates be just and reasonable, especially as other analyses indicate that data center projections may be overblown.¹⁷²

Given its focus on future conditions and unverified assumptions, the Report is not substantial evidence of an emergency under Section 202(c).

¹⁷¹ Department, [Resource Adequacy Report Evaluating the Reliability and Security of the United States Electric Grid](#) (July 2025) at 9 (emphasis added).

¹⁷² Exhibit SS (Behr, P., *PJM to ratchet down projected AI power demand for eastern US* (Jan. 6 , 2026)); Institute for Policy Integrity, [Fiscal Year 2025 Annual Report](#); London Economics International LLC, [Uncertainty and Upward Bias are Inherent in Data center Electricity Demand Projections](#) (July 7, 2025).

- iii. State planning processes have assured that the areas served by Craig Unit 1 have sufficient capacity currently and will continue to have sufficient capacity without Craig Unit 1.*

The Order notes that Colorado has retired 571.3 MW of coal generating capacity since 2019. However, the Order does not provide any evidence that these retirements have resulted in a resource shortfall in Colorado. The Order also ignores the rest of the states that are served by Craig Unit 1. All five of the Craig Unit 1 Owners' service areas have sufficient capacity for 2026-2030, well beyond the 90 day period covered by the Order, and do not need energy from Craig Unit 1 to maintain resource adequacy or reliability. Pursuant to the authority reserved to the states by the FPA, Colorado, Arizona, Wyoming, and Utah have robust electric resource planning processes that ensure resource adequacy and grid reliability. None of these states are currently part of an RTO or ISO, and therefore their electric grid is mainly managed by individual utilities and overseen by states and balancing authorities.

- a. Colorado's robust planning process ensures sufficient capacity for the State's utility customers.

For decades, Colorado has implemented robust and successful electric resource planning processes that serve as a model for other states. Colorado's process assesses resource adequacy and reliability across utilities' service territories, requires regulated utilities to use competitive resource solicitations to acquire new resources of multiple fuel types, and ensures that there will be sufficient electricity to meet expected load, even with planned plant closures.¹⁷³

¹⁷³ Exhibit C.

As part of Colorado’s overall energy planning framework, each investor-owned retail electric utility and wholesale electric generation and transmission cooperative is required to submit to the CoPUC an application for approval of an ERP.¹⁷⁴ Each Colorado ERP proceeding thoroughly considers resource adequacy and reliability at multiple stages.¹⁷⁵ In developing their forecasted resource needs, utilities’ electric energy and demand forecasts must be completed for each year within the ERP planning period and must include, among other components, the electric demand placed on the utility’s system for each hour of the day for peak-day, average-day, and representative off-peak days for each calendar month.¹⁷⁶ Utilities must “develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period[,] . . . including base case, high, and low” demand growth scenarios.¹⁷⁷ Since the announcement of Craig Unit 1’s retirement in 2016, the CoPUC has received annual resource planning reports from Tri-State and Public Service, and has conducted two adjudicated resource planning proceedings for Tri-State’s system and three for Public Service’s system, with administrative records totaling in the tens of thousands or hundreds of thousands of pages. All of these proceedings have included the planned Craig Unit 1 retirement as a foundational assumption in forecasting, modeling, and portfolio selection.

¹⁷⁴ § 40-2-125.5, Colo. Rev. Stat.; 4 Colo. Code Regs. §§ 723-3-3603(a), -3605(a).

¹⁷⁵ Exhibit C.

¹⁷⁶ 4 Colo. Code Regs. § 723-3-3605(b).

¹⁷⁷ *Id.* at -(b)(II).

In an ERP proceeding, the utility must describe and justify the means by which it assesses the desired level of system reliability, and it must propose target planning reserve margins for each forecasted scenario.¹⁷⁸ Utilities' planning reserve margin studies employ probabilistic modeling to determine the amount of capacity necessary to maintain a certain level of reliability, for example a Loss of Load Expectation of 0.1 days/year. The studies must account for a wide variety of risks, "includ[ing] risks associated with: the development of generation; losses of generation capacity, losses of transmission capability; [and] risks due to known or reasonably expected changes in environmental regulatory requirements[.]"¹⁷⁹ Planning reserve margin studies also rely on thorough analyses, for each resource type, of the Effective Load Carrying Capability ("ELCC"), or the amount of dependable capacity that can be counted on by the system for resource adequacy purposes.¹⁸⁰ Utilities are also required to present contingency plans for the acquisition of additional resources in the event demand increases or expected generation resources are not developed.¹⁸¹ Following extensive stakeholder input and vetting through rounds of testimony and cross-examination of utility's need for additional generation to be acquired through an all-source competitive resource solicitation.¹⁸² The additional generation must be able to meet system needs, including availability or dispatchability at certain hours of the day.¹⁸³

¹⁷⁸ 4 Colo. Code Regs. § 723-3-3605(e).

¹⁷⁹ *Id.* at -(e)(II).

¹⁸⁰ Exhibit C.

¹⁸¹ 4 Colo. Code Regs. § 723-3-3605(e)(III).

¹⁸² Exhibit C.

¹⁸³ *Id.*

Upon completion of a resource solicitation, the utility presents a number of potential resource portfolios. Included in this presentation are the results of additional reliability checks, which further ensure resource adequacy and reliability by demonstrating that each portfolio satisfies relevant metrics such as meeting the required planning reserve margin, meeting a Loss of Load Hours target and meeting an Annual Expected Unserved Energy target.¹⁸⁴ After opportunities for stakeholder input, the CoPUC issues a decision establishing the final cost-effective resource plan. In making this decision the CoPUC considers various statutory factors, including whether the resource plan meets the energy policy goals of Colorado, such as giving full consideration to cost-effective resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.¹⁸⁵

b. Tri-State's ERP demonstrates a reliable resource portfolio after Craig Unit 1's retirement.

Tri-State's most recent electric resource proceeding¹⁸⁶ concluded in August 2025 with the selection of Tri-State's preferred resource portfolio as the approved cost effective resource plan.¹⁸⁷ The portfolio includes the addition of 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031, replaces the turbines on one of Tri-State's gas plants to improve its capacity contributions, and maintains the retirement dates of three coal plants (including Craig Unit 1).¹⁸⁸ Tri-

¹⁸⁴ *E.g.*, Exhibit J, at 94-95.

¹⁸⁵ 4 Colo. Code Regs. § 723-3-3605(h); § 40-2-134, Colo. Rev. Stat.

¹⁸⁶ Tri-State's planning processes encompass all states in its service territory, including Wyoming and Colorado. See Exhibit X, at 6.

¹⁸⁷ Exhibit E, ¶ 90.

¹⁸⁸ Exhibit X, at 6.

State demonstrated that the portfolio meets all reliability metrics, and avoids costly transmission upgrades required by other analyzed portfolios.¹⁸⁹ Tri-State remains in a capacity-long position until 2030 but has planned on the above resource acquisitions to ensure reliability as its coal units retire in 2025, 2028, and 2030 and to maintain progress toward emissions reductions.¹⁹⁰

Tri-State supported each of the considered resource portfolios with two levels of rigorous reliability metric checks. The first level, intended to meet industry standards, required each portfolio's satisfaction of: (1) the target planning reserve margin for each year in the resource acquisition period, or 22% transitioning to 30.5% in 2028; (2) a Loss of Load Hours maximum of 1 day in 10 years and a maximum of 2.4 hours annually; and (3) an Expected Unserved Energy maximum of less than or equal to 0.4 Gigawatt hours ("GWh") annually.¹⁹¹ The second level of reliability metrics was applied to the extreme weather event sensitivities to ensure reliable service during likely future weather events, and required that this modeled sensitivity for each portfolio resulted in: (1) no more than 12 hours of expected unserved energy during all extreme weather events modeled in the years 2026-2031; (2) no more than 3 Loss of Load Hours per each year in the years 2026-2031; (3) and an Expected Unserved Energy maximum of 20% of load in any hour.¹⁹² Tri-State demonstrated that each presented resource portfolio met these reliability metrics. For the portfolio approved by the CoPUC, planning reserve margins ranged from 24% in 2025 to 34% in 2031, with

¹⁸⁹ Exhibit J.

¹⁹⁰ 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), at 30:15-16.

¹⁹¹ Exhibit J, at 18.

¹⁹² *Id.*; Exhibit W.

zero Loss of Load Hours and zero annual expected unserved energy during that period.¹⁹³

Tri-State initially proposed the planning reserve margin targets satisfied by each portfolio through a detailed analysis of grid parameters, including the reliability needs of a system transitioning away from coal generation and toward increased reliance on renewables. ELCCs were determined for each resource type to appropriately model each resource's capacity potential for the specifics of Tri-State's system, rather than relying on nameplate capacity.¹⁹⁴ Incorporating these ELCCs and the reliability standard of 0.1 Loss of Load Expectation, Tri-State proposed that after the retirement of the Craig Station and the departure of certain member loads in 2028, the target planning reserve margin be 30.5%, which is considerably higher than its existing and historic reserve margin.¹⁹⁵ These planning reserve margins were carried through to Tri-State's portfolio approved in August 2025.¹⁹⁶

In summary, every portfolio that Tri-State modeled in its most recent ERP assumed the retirement of Craig Unit 1 at the end of 2025, and every modeled portfolio met all reliability metrics, including Tri-State's approved portfolio.¹⁹⁷ And as specifically found by the CoPUC in its decision approving Tri-State's preferred

¹⁹³ Exhibit J, at 62.

¹⁹⁴ Exhibit OO (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 – Attachment G-1 (Astrape Consulting, Reserve Margin and ELCC Study, Public (Aug. 2, 2023)), at 8.

¹⁹⁵ *Id.*

¹⁹⁶ Exhibit W, at 20:8-15; Exhibit E.

¹⁹⁷ Exhibit J, Table 7: Modeled Retirements (Portfolio 1 - NEE), at 21, Table 32: Social Cost of Methane Nominal Dollars - System Wide (Portfolio 2 - NELG), at 35, Table 28: Modeled Retirements (Portfolio 2 - NELG), at 32, Table 49: Modeled Retirements (Portfolio 3 - FLEX), at 43, Table 70: Modeled Retirements (Portfolio 4 - FLEXSR), at 54, Table 91: Modeled Retirements (Portfolio 5 - NNG), at 75, Table 112: Modeled Retirements (Portfolio 6 - NNGSR), at 75.

portfolio, “Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP.”¹⁹⁸ Tri-State’s most recent ERP progress report, filed on December 1, 2025, confirms that it is progressing with contracting for its preferred portfolio resources, and using its updated load forecast, it does not forecast a capacity shortfall until 2035.¹⁹⁹

c. Colorado’s process allows the State to quickly address changes in resource needs.

Utilities must file annual progress reports on their efforts to implement approved plans and on their emerging resource needs, including an updated forecast, updated evaluations of planning reserve margins and contingency plans, and updated assessments of additional resource needs.²⁰⁰ And importantly, Colorado’s electric resource planning process also allows for the filing of interim ERPs and certificates of public convenience and necessity to fill generation needs not identified or fully satisfied by ERPs completed on the regular cadence.²⁰¹ This allows electric utilities and the State to quickly respond to changes in load or available resources.²⁰²

For example, Public Service filed a Just Transition Solicitation Plan, treated as an interim ERP, on October 15, 2024. The CoPUC issued a Phase 1 decision on November 6, 2025, that approved the Company’s ERP and established a pathway for Public Service to acquire necessary generation and storage resources and reliably

¹⁹⁸ Exhibit E, ¶ 116.

¹⁹⁹ Exhibit Z (CoPUC, Tri-State, 2025 Annual Progress Report, filed on December 1, 2025, in Proceeding No. 23A-0585E), at 8, 10-11.

²⁰⁰ 4 Colo. Code Regs. § 723-3-3618.

²⁰¹ 4 Colo. Code Regs. §§ 723-3-3603(a), 3605(a)(II); Exhibit C.

²⁰² *Id.*

serve existing and future customers.²⁰³ Like Tri-State, Public Service has filed previous ERPs that all accounted for the retirement of Craig Unit 1.²⁰⁴

Public Service has not indicated a need for energy from Craig Unit 1 to meet any immediate or longer-term resource needs. Public Service's ERPs demonstrate it is not anticipated to have a shortfall in the next 90 days, as Public Service is a summer peaking system. In recent filings before the CoPUC, Public Service raised some concerns for the summers of 2026 and 2027, which do not begin for another six months. Colorado is already acting to address Public Service's concerns. In December 2025, the CoPUC approved an extension of the retirement date for a Public Service coal plant located in Pueblo, finding that the delay of the planned Comanche Unit 2 retirement date until December 31, 2026, is necessary due to the unplanned outage of another coal unit, Comanche Unit 3.²⁰⁵ Public Service is also engaging in a near-term procurement process within an older ERP proceeding to acquire additional resources to be deployed prior to 2031.²⁰⁶ Thus, Colorado has flexible procedures that assure resource adequacy in the State, even when there are unforeseen events.

²⁰³ CoPUC, Decision No. C25-0747, issued on November 6, 2025, in Proceeding No. 24A-0442E, ¶ 2.

²⁰⁴ Exhibit C, ¶¶ 27-31.

²⁰⁵ Exhibit BB, (CoPUC, Decision No. C25-0892, issued on December 10, 2020, in Proceeding No. 25V-0480E), ¶ 65. On November 10, 2025, the Colorado Energy Office, Trial Staff of the Public Utilities Commission, the Colorado Office of the Utility Consumer Advocate, and Public Service submitted a petition to the CoPUC requesting that a coal plant, Comanche Unit 2, which was also scheduled to retire on December 31, 2025, remain open for another year. See Exhibit Y (CoPUC, *Verified Petition of Trial Staff of the Commission, Colorado Energy Office, the Colorado Office of the Utility Consumer Advocate, 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).

²⁰⁶ Exhibit N.

PRPA, though not overseen by the CoPUC, develops an Integrated Resource Plan (“IRP”) to conduct long-term resource planning and ensure resource adequacy.²⁰⁷ PRPA ran all of its scenarios to meet a planning reserve margin of 19.9%.²⁰⁸ With its current and committed resources, PRPA has enough capacity to maintain a 19.9% planning reserve margin through 2029.²⁰⁹ PRPA began commercial operation of a 150 MW solar project in 2025,²¹⁰ plans to begin a 130 MW solar project in 2027, and is beginning processes to obtain additional dispatchable capacity.²¹¹ PRPA has no resource adequacy issues now or forecasted upon the retirement of Craig Unit 1. As shown by its annual required filing with the Colorado Energy Office, its capacity well exceeds forecasted demand with a total accredited capacity of 885 MW and a native load forecast of 722 MW for 2026, leading to a planning reserve margin of 25.4%.²¹² PRPA’s General Manager and CEO has publicly stated that the utility does “not need the Craig 1 unit because it has already replaced the energy that came from it.”²¹³

d. The other states served by Craig Unit 1 also oversee resource planning to ensure reliability and adequate capacity.

Although the majority of Craig Unit 1’s energy serves Colorado, and Colorado is the only state the Order specifically discusses, Utah and Arizona also receive energy from Craig Unit 1, through PacifiCorp and Arizona respectively. Each of these states has extensive resource planning processes.

²⁰⁷ Exhibit EE.

²⁰⁸ *Id.*

²⁰⁹ *Id.*

²¹⁰ PRPA, [Solar Energy](#) (2026).

²¹¹ Exhibit EE, at 178.

²¹² PRPA, [Worksheet Certification Form](#) (Apr. 28, 2025).

²¹³ Exhibit RR (Powell, R., *1 coal plant open amid order* (Jan. 6, 2026)) at 3.

The Utah Public Service Commission (“Utah PSC”) has the power to supervise and regulate every public utility in Utah.²¹⁴ The Utah PSC regulates IRPs, including PacifiCorp’s IRPs.²¹⁵ Utah utilities are also required to maintain a written reliability program.²¹⁶ PacifiCorp has a 2025 IRP that is specific to Utah, which Colorado understands to be the part of PacifiCorp’s service territory that is sometimes served by Craig Unit 1’s energy.²¹⁷ That IRP indicates that PacifiCorp expects to acquire 6,379 MW of new wind resources, 7,668 MW of storage resource, 5,492 MW of solar, and 500 MW of nuclear.²¹⁸ Currently, PacifiCorp owns 11,700 MW of generation capacity, meaning that its 82 MW from Craig Unit 1 makes up 0.7% of its generation capacity.²¹⁹ PacifiCorp acknowledges that coal resources have been an important resource in its portfolio in the past, but material changes in how PacifiCorp operates those assets has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low cost zero emission renewable energy from market participants.²²⁰ PacifiCorp is well above its winter system capacity planning reserve margin of 16.8% through 2028²²¹ and has expressed no need to keep Craig Unit 1 online.

²¹⁴ [Utah Code Ann. § 54-4-S1 \(2024\)](#).

²¹⁵ [Utah Code Ann. § 54-17-301 \(2025\)](#).

²¹⁶ [Utah Admin. Code R746-313-4 \(2025\)](#).

²¹⁷ Exhibit GG (PacifiCorp, *Utah Integrated Resource Plan Volume I* (Mar. 31, 2025)).

²¹⁸ *Id.* at 37.

²¹⁹ PacifiCorp, [Powering a bright future](#) (2026).

²²⁰ Exhibit GG.

²²¹ *Id.* at 265.

The Arizona Corporation Commission (“ACC”) oversees the electric power industry in Arizona.²²² Load-serving entities, including Salt River Project, are required to annually file demand and supply side data, a forecast of peak load, and a 15-year resource plan that “[w]ill result in the load-serving entity’s reliably serving the demand for electric energy services,” with the ACC.²²³ The Salt River Project conducts long-term resource planning to anticipate and meet future needs, most recently through their 2023 Integrated System Plan (“ISP”),²²⁴ where the Salt River Project modeled multiple future scenarios to ensure that it would be resource adequate through 2035. The ISP plans for new resource acquisitions and accounts for all coal plant retirements. The ISP had all scenarios except two meet their requisite 16% planning reserve margin. The two scenarios that did not meet the PRM are more extreme scenarios where firm resource options are limited and there is accelerated load growth, but even in those two cases reliability would not be compromised until 2028.²²⁵ Salt River Project did not pursue analysis of those scenarios, since they are not viable due to not achieving the planned reserve margin, even as far out as 2028.²²⁶ Neither the ACC nor the Salt River Project have expressed concerns about resource adequacy and have been strategically planning for coal unit retirements. Salt River Project has construction “underway for 575 MW of new flexible natural gas resources and 55 MW of solar” and “is finalizing agreements for 480 MW of [additional] solar and 1300 MW of battery storage projects.”²²⁷ Further, Salt River Project receives its energy from Craig Unit 1 through an exchange with WAPA, where WAPA makes the necessary transmission available. However, that arrangement

terminates on April 1, 2026, and it is unclear how Salt River Project would get energy from Craig Unit 1 after that date.

The extensive planning processes conducted by the owners of Craig Unit 1 have ensured that the unit's retirement will not negatively impact the reliability of any of their electric grids. All of the utilities are resource adequate for the 90 days covered by the Order and none of them have expressed a need for Craig Unit 1.

e. FERC's oversight ensures reliability at the regional level.

In addition to these extensive state processes developed under the states' sovereign authority, the Craig Unit 1 Owners are all overseen by a variety of authorities, acting under FERC's delegated authority. As noted above, the FPA places this authority with FERC and does not provide any authority for oversight of long-term resource planning to the Department in Section 202(c). The FERC and state processes work together to ensure reliability, and the Order illegally intrudes on these processes without any reasonable basis.

The Order instructs Craig Unit 1 to be available to operate at the direction of SPP or WACM.²²⁸ SPP is the reliability coordinator for Tri-State, PRPA, and Public Service.²²⁹ SPP has been a reliability coordinator for over 20 years and has extensive operating criteria, outage coordination methodology, and emergency protocols.²³⁰ SPP

²²² ACC, [Utilities Division](#).

²²³ [Ariz. Admin. Code R14-2-703.F.2.](#) (2025).

²²⁴ Exhibit H.

²²⁵ *Id.*, at 104-105.

²²⁶ *Id.*

²²⁷ SRP, [Integrated System Plan: ISP Actions Progress Report 2025](#) at 7.

²²⁸ Exhibit A.

²²⁹ SPP, [Western RC Services](#) (2026).

²³⁰ SPP, [Operating Reliability](#) (2026).

has a Reliability Plan that details how it monitors for and responds to an emergency.²³¹ Like all Reliability Coordinators, SPP has “a wide-area view, operating tools, processes and procedures to prevent or mitigate emergency operating situations in next day analysis and real-time conditions[]” and has the authority to act and instruct its members to take actions to preserve the integrity and reliability of the bulk electric system.²³² Likewise, balancing authorities ensure that power system demand and supply are balanced and are responsible for maintaining operating conditions under mandatory NERC reliability standards.²³³ WACM is a Balancing Authority overseen by SPP as a reliability coordinator.²³⁴

An energy emergency is defined by NERC and WECC as a situation when a load serving entity has exhausted all options for obtaining capacity and can no longer provide its customers with expected energy requirements.²³⁵ A reliability coordinator will initiate an energy emergency alert at their own request, upon the request of a Balancing Authority, or upon the request of a load serving entity.²³⁶ Reliability Coordinators and balancing authorities make the decision to call or request the calling

²³¹ Exhibit HH (SPP, *SPP Reliability Plan* (Jun 2, 2025)).

²³² *Id.*, at 6-7.

²³³ Department, [Learning Series: Energy Security & Resilience](#).

²³⁴ SPP, [Western RC Services](#) (2026).

²³⁵ WECC, [Standard EOP-002-2 - Capacity and Energy Emergencies](#) (2007).

²³⁶ *Id.* At an Energy Emergency Alert Level 1, a Balancing Authority will call on all available power supplies, regardless of economics, including from other grids, and enable demand-side resource deployments. # At an Energy Emergency Alert Level 2, a Balancing Authority will initiate demand response programs that shed load from large industrial customers that have contractually agreed to do so and will publicly appeal to customers to cut back on electricity consumption. # If the highest level of emergency, Energy Emergency Alert Level 3, is called, then Reliability Coordinators will conduct emergency operating procedures to increase transfer capabilities into the entity declaring the emergency. NERC has general emergency operating instructions that address the effects of emergencies by ensuring each transmission operator and Balancing Authority has developed plans to mitigate operating emergencies and those plans are implemented and coordinated within the reliability coordinator. Exhibit II (NERC, Emergency Operations).

of an emergency pursuant to their emergency plans and operating procedures. WACM and SPP have not done so in this case, despite having the same (or likely more) information as the Department does about the reliability of the grid in the areas served by Craig Unit 1.

Therefore, if an emergency did occur in the areas served by Craig Unit 1 or in the WECC-Northwest assessment area, there are extensive procedures in place for that emergency to be handled by the complex and comprehensive network of the utilities themselves, Reliability Coordinators, and balancing authorities without the Department overstepping and preemptively trying to solve an emergency that has not occurred, and is not predicted to occur in any relevant assessment. The Order states merely that there is an emergency in the WECC-Northwest assessment area because of increasing peak demand and baseload generation retirements, without actually citing any reliability issues that have stemmed from those conditions. There is no evidence, and the Order cites none, that an emergency within the WECC system could not be handled by WECC's existing procedures and the existing mix of resources available in the region upon Craig Unit 1's retirement.

iv. The Executive Orders cited in the Order are not evidence of an energy emergency.

The Order also relies on the Energy Emergency and Grid Reliability Executive Orders as evidence of an energy emergency, generally stating that the Energy Emergency and Grid Reliability Executive Orders underscore the energy challenges facing the Nation due to growing resource adequacy concerns.²³⁷ However, neither of

²³⁷ Exhibit A.

these executive orders present evidence of an energy emergency in the WECC-Northwest Assessment Area or any other region of the county within the meaning of Section 202(c).²³⁸

On January 20, 2025, President Trump issued Executive Order 14156, *Declaring a National Energy Emergency* (“Energy Emergency Executive Order”).²³⁹ Despite its title, the Energy Emergency Executive Order fails to describe any type of energy emergency. It generically claims “[t]he energy ... generation capacity of the United States [is] far too inadequate to meet our Nation’s needs,” and the situation “will dramatically deteriorate in the near future...”²⁴⁰ The Energy Emergency Executive Order also specifically calls out the Northeast and West Coast states, claiming those states’ “dangerous” “policies jeopardize our Nation’s core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population.”²⁴¹ The Executive Order does not identify any specific policies or explain how they are jeopardizing grid reliability.

President Trump then issued Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, (“Grid Reliability Executive Order”) on April 8, 2025.²⁴² The Grid Executive Order also claims that the country is “experiencing an unprecedented surge in electricity demand,” generically pointing to expansions of data centers and increases in domestic manufacturing as

²³⁸ See 10 C.F.R. § 205.371 (defining emergency as a “specific inadequate power supply situation”).

²³⁹ [Exec. Order 14156](#), 90 Fed. Reg. 8,433, 8,434 (Jan. 20, 2025).

²⁴⁰ *Id.*, at Sec. 1.

²⁴¹ *Id.*, at 8,434.

²⁴² Exec. Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, 90 Fed. Reg. 15,521 (April 14, 2025).

demand drivers.²⁴³ These vague statements on nationwide energy needs are not sufficiently specific to justify a Section 202(c) order.

Neither of these Executive Orders provide data or other evidence in support of their claims of inadequate nationwide generation, let alone evidence of inadequate generation in the areas served by Craig Unit 1 such that they could constitute the evidence required to support the Order. The Energy Emergency Executive Order refers to a deterioration “in the near future,”²⁴⁴ while the Grid Reliability Executive Order offers no projection for the timing or location of the increased demand it speculates.²⁴⁵ This does not satisfy Section 202(c)’s requirements, discussed above in Section V.A., that an emergency must be specific and imminent.

Importantly, the facts contradict the vague assertions of an energy emergency contained in the Executive Orders. For example, America’s domestic energy production is at an all-time high given its diverse mix of both fossil and non-fossil fuel resources. The United States is producing record quantities of oil and natural gas,²⁴⁶ and has been a net energy exporter since 2019.²⁴⁷

Similarly, the Energy Emergency Executive Order’s assertion that the United States has an “inadequate and intermittent energy supply, and an increasingly unreliable grid” is unsupported by the facts.²⁴⁸ NERC reports that the bulk power

²⁴³ *Id.*

²⁴⁴ [Exec. Order 14156](#), 90 Fed. Reg. at 8,433.

²⁴⁵ Exec. Order 14262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521 (Apr. 8, 2025).

²⁴⁶ U.S. Energy Information Admin. (“EIA”), [Short-Term Energy Outlook Data Browser](#) (Jan. 13, 2026).

²⁴⁷ EIA, [In-Brief Analysis: The United States was the world’s largest liquified natural gas exporter in 2023](#) (Apr. 1, 2024); EIA, [U.S. Exports of Crude Oil](#) (Dec. 31, 2025); EIA, [U.S. Energy Facts Explained](#) (July 15, 2024).

²⁴⁸ [Exec. Order 14156](#), 90 Fed. Reg. at 8,433.

system is resilient, and that the largest challenge for reliability is extreme weather induced by climate change.²⁴⁹ Renewable energy resources both mitigate climate change and improve the overall reliability and affordability of the United States' energy supply by tempering the impact of international commodity price swings on natural gas prices and reducing grid operators' reliance on interruptible natural gas deliveries.²⁵⁰ Solar and wind generated more than 15% of all electricity and 8% of all energy consumed in the United States in 2024.²⁵¹

Next, the Order relies in part on “the expansion of artificial intelligence data centers” referenced in the Grid Reliability Executive Order and other projected demand growth noted in the Department Resource Adequacy Report to support its finding of an emergency.²⁵² But the Order's discussion of data center load growth is both irrelevant and unsubstantiated.

Neither the Grid Reliability Executive Order nor the Order specify any timeframe for when the increased energy demand from data centers is expected to occur. Section 202(c) does not give the Department the authority to retain generation units for possible conditions that may arise at some indeterminate time in the future. Authority to address long-term threats to resource adequacy rests with the states and FERC and its designated entities, all of which are aware of and extensively planning for this potential load growth. The Order does not cite any evidence that data center

²⁴⁹ NERC, [2024 State of Reliability](#) (June 2024), at 5.

²⁵⁰ FERC, [The February 2021 Cold Weather Outages in Texas and the South Central United States](#) (Nov. 16, 2021), at 172 (“Natural gas fuel supply issues alone caused 27.3[%] of the generating unit outages” during Winter Storm Uri).

²⁵¹ EIA, [Short-Term Energy Outlook](#) (Feb. 11, 2025), see the 2024 data; EIA, [December 2025 Monthly Energy Review](#) (Dec. 23, 2025).

²⁵² Exhibit A, at 2-3.

load growth will occur in the areas served by Craig Unit 1 during the 90 day period of the Order. As demonstrated in their respective resource plans, the Craig Unit 1 owners are not anticipating any new data centers or other large loads over 50 MW to come online in their service territory in the next 90 days.²⁵³ And where Colorado utilities anticipate data centers coming online in the next five years, they are planning for that additional load through their established resource planning processes.

D. The Order is arbitrary and capricious because it fails to require generation that best meets the claimed emergency.

Even if there were an emergency within the meaning of the FPA, which there is not, Section 202(c)(1) requires the Department to impose requirements that “will best meet the emergency and serve the public interest.”²⁵⁴ The Department has failed to demonstrate that delaying the retirement of Craig Unit 1 satisfies this standard, and the Order is therefore arbitrary and capricious.

i. Preventing Craig Unit 1’s retirement does not “meet the emergency,” especially where the unit requires costly repairs.

It is unclear how preventing Craig Unit 1’s retirement could meet the emergency that the Department alleges. The nature and extent of the claimed emergency are unclear. And even if there were a capacity shortfall in any of the states served by Craig Unit 1 or the WECC-Northwest assessment area, the Order does not provide a reasoned basis for its conclusion that the continued operation of Craig

²⁵³ See Section V.C.iii., *supra*.

²⁵⁴ 16 U.S.C. § 824a(c)(1).

Unit 1 is the best or even a viable means of alleviating the purported shortfall, particularly in light of the costly repairs required to make Craig Unit 1 available.

The Department cannot demonstrate that Craig Unit 1's retirement meets the emergency because the Order's emergency declaration is unclear and unsupported by the record. The Order does not specify which version of the WECC-Northwest assessment area it is relying upon, which is essential because the assessment areas significantly changed after the 2024 LTRA assessment. This is further confused by the Order's next reference to the WECC-Northwest assessment area being that the "WECC[-]Northwest assessment area, which includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming..." despite the fact that in the 2024 LTRA, that assessment area also includes parts of California, Nebraska, Nevada, and South Dakota.²⁵⁵ Regardless, assuming that the order only refers to the states it called out specifically, Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, it is Colorado's understanding that Craig Unit 1 is only capable of serving three of those states. The Order also fails to demonstrate that there is a resource shortfall imminent and specific enough to require the continued operation of any particular resource. Thus, it is unclear how Craig Unit 1 could meet the Department's alleged emergency, regardless of how the Order's emergency determination is interpreted.

²⁵⁵ Exhibit K, at 127.

- ii. *Delaying the retirement of Craig Unit 1 does not “best” meet the Department’s purported emergency.*

Even if delaying the retirement of Craig Unit 1 could meet the non-existent alleged emergency in the WECC-Northwest assessment area, the Department has provided no explanation of how that resource would best meet such an emergency. “Best” means “that which is ‘most advantageous’” or “excelling all others.”²⁵⁶

The Order, and the materials upon which it relies, offer no facts that would support a determination that Craig Unit 1 is the “most advantageous” way to address the alleged emergency. Even if the Order had successfully described an emergency scenario for the regions served by Craig Unit 1 or the WECC-Northwest assessment area, the Department has not provided any specific evidence or reasoning explaining why requiring Craig Unit 1 to be available to operate is the most advantageous way to meet the scenario. Other orders issued by the Department in 2025 suffer from the same flaw, as the Congressional Research Service identified in July 2025, noting that Orders issued to the Campbell and Eddystone units have not “identified reliability risks specifically associated with the retirement of the power plants in question at the time they approved those retirements.”²⁵⁷ In this respect, the Department’s exercise of its emergency authority in 2025 departs markedly from past uses of Section 202(c) and from the Department’s regulations implementing Section 202(c). Those

²⁵⁶ *Entergy Corp.*, 556 U.S. at 218 (quoting Webster’s New International Dictionary 258 (2d ed.1953)); [Best](#), Merriam-Webster Dictionary (Jan. 25, 2026).

²⁵⁷ Exhibit T (Congressional Research Service, Federal Power Act: The Department of Energy’s Emergency Authority (June 12, 2025)), at 5-6.

regulations specify that: “[a]ctions under this authority are envisioned as meeting a specific inadequate power supply situation.”²⁵⁸

“Best’s” definition of “excelling all others” requires a comparative judgment that there are no better alternatives. This means the Department must consider alternatives and choose the alternative that is most advantageous to meet the emergency the Department has identified. The Department need not consider every conceivable alternative, but it must consider alternatives within the ambit of the existing policy as well as alternatives which are significant and viable or obvious.²⁵⁹

The Department’s regulations specify information the Department must consider in deciding how to best address an emergency in a Section 202(c) order. This includes conservation or load reduction actions, efforts to obtain additional power through voluntary means, available imports, demand response, and behind the meter generation resources.²⁶⁰ The Order considers none of these alternatives. Nor does it explain whether less burdensome measures were considered or exhausted before invoking the Department’s emergency authority. Indeed, the Order never quantifies the extent of the emergency it purports to identify within Colorado or any of the states served by Craig Unit 1, making a meaningful alternatives analysis impossible. As discussed in Section V.B.iii, each of the areas served by Craig Unit 1 have significant planning reserve margins. To satisfy Section 202(c)(1)’s requirement that the ordered

²⁵⁸ 10 C.F.R. § 205.371.

²⁵⁹ See *Dep’t of Homeland Sec.*, 591 U.S. at 30 (failure to consider alternative was arbitrary and capricious); see also *Motor Vehicle Mfrs. Ass’n*, 463 U.S. at 51 (must consider alternatives “within the ambit of the existing [standard]”).

²⁶⁰ 10 C.F.R. § 205.373(g)-(h). While this information is specifically required when a utility applies for a 202(c) order, it illustrates the types of information that is relevant to an alternatives analysis.

solution best meet the emergency, the Order must address why the resources that make up the excess planned reserve margins could not meet the alleged emergency.

This is a particularly glaring omission because the Department addressed their alleged emergency by ordering an inoperable coal unit that required significant repairs to become available to operate,²⁶¹ despite the reserve capacity in the region. Craig Unit 1 experienced an outage on December 19, 2025, due to a mechanical valve failure.²⁶² The Unit was not repaired until January 20, 2025,²⁶³ a third of the way into this 90 day order, and required spending significant resources that would not have been expended absent the Order.²⁶⁴

In addition to the significant cost just to make Craig Unit 1 available to operate after the valve failure, Tri-State has stated that retaining Unit 1 “will likely require additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs.”²⁶⁵ The Craig Unit 1 Owners chose to retire Craig Unit 1 for economic reasons.²⁶⁶ And because the unit was set to retire, Craig Unit 1 has not had major maintenance since 2019;²⁶⁷ it is also 45 years old, beyond the typical economic design life of a coal burning generator and near the end of a

²⁶¹ See Exhibit B, ¶ 11.

²⁶² Tri-State, [U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days](#) (Dec. 31, 2025).

²⁶³ Tri-State, [Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order](#) (Jan. 23, 2026).

²⁶⁴ Tri-State, [U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days](#) (Dec. 31, 2025).

²⁶⁵ *Id.*

²⁶⁶ Tri-State, [Craig Station owners, regulators and environmental groups reach agreement on proposed revisions to Colorado regional haze plan](#) (Sept. 1, 2016).

²⁶⁷ Exhibit B at ¶ 34.

generator's typical operational life.²⁶⁸ Keeping Craig Unit 1 running will be more costly now because of the deferred maintenance costs in addition to costs for fuel and continued operations.²⁶⁹ Colorado's understanding is that Tri-State has, since the issuance of the Order, already begun to expend costs on some of this maintenance.²⁷⁰ These costs are currently unknown but expected to be significant. It is unclear how Tri-State and the other co-owners will recover these costs, but it is highly likely that they will seek to have ratepayers pay them.²⁷¹

Complicating the fuel issue, Tri-State did not plan on continuing to acquire or use coal for Craig Unit 1 due to its scheduled retirement. Craig Station is supplied with coal from the Colowyo Mine, which ceased coal production at the end of 2025.²⁷² Tri-State has already contracted with Kiewit Mining Group, Inc., to reclaim the mine following its closure, and reclamation activities were scheduled to begin on or about January 1, 2026.²⁷³ Moreover, the Colowyo mine has been sterilized, meaning it will not be reopened and its operator has transitioned to reclamation activities.²⁷⁴ It is Colorado's understanding that before the mine's closure, Tri-State obtained enough coal to fuel Craig Units 2 and 3 through their planned retirement dates in 2028 but did not expect to need coal to power Craig Unit 1. If Tri-State needs to use coal acquired

²⁶⁸ Grid Strategies, *The Economic Cost of a DOE Mandate for the Craig Unit 1 Coal-Burning Generator to Continue Operating* (Dec. 2025), at 2.

²⁶⁹ Exhibit D ¶¶ 14-15.

²⁷⁰ See Exhibit B, ¶ 34.

²⁷¹ Exhibit D ¶ 18.

²⁷² Jaffe, M., [Tri-State expects federal order to keep coal-fired power plant in northwestern Colorado running](#) (Nov. 14, 2025).

²⁷³ Tri-State, [Colowyo Mine to conclude coal production in 2025, transitioning to full reclamation](#) (Aug. 7, 2025).

²⁷⁴ Weiser, C., [Colowyo coal mine near Craig lays off 133 workers as mine closes](#) (Nov. 26, 2025); WarnTracker.com, [1 WARN Layoff Notice for ColoWho Coal Company LP on Nov 2025](#) (2025).

to fuel Craig Units 2 and 3 to unexpectedly fuel Craig Unit 1, it will likely not have enough supply to also fuel the other units. Tri-State would then have to buy more expensive, and possibly dirtier, coal from another source.²⁷⁵

In addition, coal generation is generally more costly than other generation resources.²⁷⁶ The inefficiency of running a coal plant makes it uneconomic in general and is the main reason that Craig Unit 1 (and eventually, the rest of Craig Station) was slated for retirement. In fact, the CoPUC approved coal fired generating unit retirements to be replaced with lower cost wind, solar, and use of gas as a capacity resource because wind and solar were the lowest cost resources available and it was cheaper to add new renewables, storage and gas generation to the system and retire coal units.²⁷⁷

Coal generation also does not guarantee reliability, which further emphasizes that Craig Unit 1 would not best meet any emergency. A 2021 report by the CoPUC found that Comanche Unit 3, Colorado's newest coal plant, which supplies portions of Public Service's territory, averaged 91.3 days per year of outages and was out of

²⁷⁵ See Exhibit B, ¶ 32.

²⁷⁶ Weiser, C., [Colowyo coal mine near Craig lays off 133 workers as mine closes](#) (Nov. 26, 2025). A report by Grid Strategies found that ratepayer costs could exceed \$3 billion per year if the Department mandates that all of the fossil power plants scheduled to retire between the time the report was published in August 2025 and the end of 2028 remain open. Grid Strategies asserts that the Department is ignoring the careful planning of states and utilities and "overriding cost-minimizing retirement decisions that have been made by state utility regulators and merchant power plant owners based on extensive information regarding the cost, performance, condition, and need for each plant." see also Grid Strategies, LLC, [The Cost of Federal Mandates to Retain Fossil-Burning Power Plants](#) (Aug. 2025) at 3; Exhibit O, which cost a staggering \$29 million over the first 38 days; Solomon, M., et al., [Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment](#) (Jan. 2023), at 1-2 (a report by Energy Innovation found that "99[%] of all coal-fired plants in the U.S. are more expensive to operate on a forward looking basis than the all-in cost of renewable energy projects," and that "all but one of the country's 210 coal plants are more expensive to operate than either new wind or solar.").

²⁷⁷ CoPUC, Decision No. C18-0761, issued on September 10, 2018, in Proceeding No. 16A-0396E, ¶ 103.

service for nearly all of 2020.²⁷⁸ In fact, when Public Service experienced a supply constraint in Summer of 2025, 80% of its unavailable power was caused by coal unit outages.²⁷⁹

This is not just true in Colorado, but also in other states, yet the Department has ignored this reality in issuing Section 202(c) orders. For example, the R.M. Schahfer Generating Station has been in a forced outage since July, after experiencing another forced outage from February 16, 2025 to June 23, 2025.²⁸⁰ Yet, despite the unit being offline, the Department issued an order requiring it to remain available on December 23, 2025.²⁸¹ Finally, the newest large coal-fired plant in the U.S. suffered an outage in fall of 2025 and will now be offline until March 2027.²⁸² This is the second time that plant has been unable to operate for a year or more.

These facts illustrate a clear pattern: coal is not the first choice when considering reliable, affordable generation. And the Order contains no facts (either in its text or in the cited materials) that supports any determination that ordering continued availability and operation of an off-line coal unit is a reasonable response to a perceived emergency, much less “best meets” such an emergency. Given the cost of Craig Unit 1 and questions of reliability surrounding coal plants generally, the

²⁷⁸ Kohler, J., [Comanche 3, Xcel Energy's troubled coal plant, likely out of commission for months](#) (Oct. 24, 2025); CoPUC, *Staff Report Volume 1*, Public, filed on March 1, 2021, in Proceeding 20I-0437E, at 65.

²⁷⁹ Kohler, J., [Comanche 3, Xcel Energy's troubled coal plant, likely out of commission for months](#) (Oct. 24, 2025).

²⁸⁰ *Id.*

²⁸¹ Exhibit S.

²⁸² Institute for Energy Economics and Financial Analysis, [Newest big U.S. coal-plant offline until 2027](#) (Oct. 7, 2025); Tri-State, [Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order](#) (Jan. 23, 2026).

Department has failed to demonstrate that Craig Unit 1's continued operation "best meets the emergency" and therefore the Order is arbitrary and capricious

E. The Order's terms fail to comply with Section 202(c)'s requirements.

- i. The Order is contrary to law because it attempts to regulate a generation facility by requiring the Craig Unit 1 Owners to undertake substantial and expensive repairs that they otherwise would not conduct.*

Given that Craig Unit 1 was offline at the time the Order was issued, compliance with the Order required the repair of Craig Unit 1.²⁸³ This requirement is outside the scope of the Department's Section 202(c) authority, even if there was adequate proof of an energy emergency.

The Department's emergency power under Section 202(c) is bounded both by the provision's specific language and Congress's clear, repeated direction in the FPA to respect the states' authority over generating facilities. When an actual emergency exists, Section 202(c)(1) authorizes the Department to require just two specific things: (1) "temporary connection of facilities" and (2) "generation, delivery, interchange, or transmission of electric energy."²⁸⁴ The only reference to "facilities" in the authorizing provision of Section 202(c)(1) appears in the clause relating to temporary connections, not in the clause pertaining to "generation" of electric energy. And that clause authorizes only "connections" of facilities: it does not provide authority to regulate the individual facilities. The difference in Congress's

²⁸³ Exhibit B, ¶ 11; Tri-State, [Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order](#) (Jan. 23, 2026).

²⁸⁴ 16 U.S.C. § 824a(c)(1).

word choice in these clauses - referencing “facilities” in one authorizing provision but not the other - must be given effect.²⁸⁵

As discussed above in Section V.C.i., Section 201(b)(1) of the FPA specifically states that unless otherwise provided, there is no federal jurisdiction over “facilities used for the generation of electric energy.” Courts have also held that Section 201(b)(1) reserves authority over electric generating authority to the states, reiterating that states retain the right “to require the retirement of existing generators.”²⁸⁶ Given Congress’s use of the term “generating facilities” elsewhere in the statute, if it had intended to give the Department authority in Section 202(c)(1) over generating facilities that otherwise resides with the states, it would have had to do so explicitly.²⁸⁷ Instead, the provision conspicuously excludes authority to manage the physical characteristics of power plants.

Thus, Congress purposely limited and particularized the Department’s emergency powers, carefully avoiding intrusion on the states’ authority over generating facilities recognized in Section 201(b)(1). As stated in the legislative history, the emergency powers in Section 202(c)(1) “which were indefinite in the original bill have been spelled out with particularity.”²⁸⁸ The Department may neither directly regulate generation facilities nor impose requirements aimed at the facilities,

²⁸⁵ See e.g. *Gallardo v. Marsteller*, 596 U.S. 420, 430 (2022); see also *Gomez-Perez v. Potter*, 553 U.S. 474, 486 (2008).

²⁸⁶ *Conn. Dep’t of Pub. Util.*, 569 F.3d at 481; see also, e.g., *Hughes*, 578 U.S. at 155.

²⁸⁷ *Gregory*, 501 U.S. at 460 (The clear statement rule requires Congress to make its intent unmistakably clear if it intends a statute to alter the usual constitutional balance between the federal government and the states.); see also *DeMarco*, 4 F.3d at 169 (Congress must express an affirmative intention to use a statute to alter the federal balance.)

²⁸⁸ See S. Rep. No. 74-621, at 19 (1935).

even if nominally regulating within its sphere.²⁸⁹ This means that the Department may not require generation that necessitates the utility taking steps reserved to state authority, such as building a new generating unit or refurbishing a broken one. Therefore, the Order is outside the bounds of its Section 202(c) authority even if there is an emergency, because it managed the physical characteristics of Craig Unit 1 by requiring its repair.

ii. The Order violates Section 202(c)(2) because it fails to ensure consistency with federal and state environmental laws and fails to minimize adverse environmental impacts.

Section 202(c)(2) imposes mandatory duties on the Department if a 202(c) order “may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation[.]”²⁹⁰ The Order explicitly conflicts with the environmental laws and regulations that apply to the Craig Station Unit 1 Owners, and may also result in additional conflicts with environmental laws and regulations that apply to the State of Colorado.²⁹¹ The Department failed to comply with these requirements, rendering the Order illegal.

a. The Order directly conflicts with federal and state laws requiring Craig Unit 1 to close by December 31, 2025.

The Order directly conflicts with federal and state environmental laws and regulations that require the closure of Craig Unit 1 by December 31, 2025. These include Colorado Air Quality Control Commission (“AQCC”) Regulation Number 23,

²⁸⁹ See *F.E.R.C. v. Elec. Power Supply Ass’n*, 577 U.S. 260, 281-82 (2016); see also *Hughes*, 578 U.S. at 164-65.

²⁹⁰ 16 U.S.C. § 824a(c)(2) (emphasis added).

²⁹¹ See Exhibit B.

Colorado's Regional Haze SIP adopted pursuant to the Federal Clean Air Act, and Tri-State's operating permit issued pursuant to Title V of the Federal Clean Air Act.²⁹²

The AQCC (with the Craig Station owners' consent) adopted the December 31, 2025 closure date into state law through Regulation Number 23, which regulates regional haze.²⁹³ The EPA then approved this closure date into federal law when it approved Colorado's Regional Haze SIP in 2018.²⁹⁴ In addition, Craig Unit 1 is a major source of air pollution²⁹⁵ and therefore requires, and operates under, an operating permit issued pursuant to Title V of the Federal Clean Air Act.²⁹⁶ A Title V permit includes emissions limits, operational requirements, reporting obligations, and other requirements to ensure the safe and environmentally responsible operation of major sources. Condition 1.10 of Craig Unit 1's operating permit specifies that the Unit must close on or before December 31, 2025.²⁹⁷

In addition, the Colorado Legislature directed the AQCC to adopt rules to help meet statewide statutory GHG reduction goals.²⁹⁸ The Order's direction for continued availability and operation of Craig Unit 1 may restrict Colorado's ability to meet these statutory goals.

²⁹² *Id.*

²⁹³ See 5 Colo. Code Reg. § 1001-27:A.IV.D.

²⁹⁴ Air Plan Disapproval; Colorado; Regional Haze Plan for the Second Implementation Period, 91 Fed. Reg. 3,048, 3,049, fn. 9 (Jan. 26, 2026); EPA, [EPA Approved Statutes and Regulations in the Colorado SIP](#) (Jan. 6, 2026); 83 Fed. Reg. 31,332 (July 5, 2018).

²⁹⁵ Craig Station is a major source and Craig Unit 1, by volume of pollution emitted, is itself a major source. Exhibit B at 27; Exhibit KK (Division, *Operating Permit No. 96OPMF155* (July 1, 2021));

²⁹⁶ See Exhibit KK; 42 U.S.C. § 7661a(a).

²⁹⁷ See Exhibit KK, at 25.

²⁹⁸ See § 25-7-105(1)(e), Colo. Rev. Stat.; Exhibit B, ¶ 29; § 25-7-102(2)(g), Colo. Rev. Stat.

Thus, by ordering the Craig Station owners to return Craig Unit 1 to service and to be available to operate beyond the December 31, 2025 closure date, the Order directs the owners to violate both state and federal law and is subject to the requirements of Section 202(c)(2).

b. The Order does not comply with Section 202(c)(2).

Because the Order conflicts with state and federal environmental laws, the Department was required to ensure that the Order: 1) “requires generation, delivery, interchange, or transmission of electric energy *only* during hours necessary to meet the emergency and serve the public interest,” 2) “to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation,” and 3) “minimizes any adverse environmental impacts.”²⁹⁹ The Department’s Order contains no conditions or instructions that meet these requirements.

First, by referring to the “hours” necessary to meet the emergency, Congress placed a high burden on the Department to demonstrate that the remedy provided in a Section 202(c) order is narrowly tailored to the specifics of the emergency that the order is designed to address. Even if the Department had identified a true emergency (which it has not), the FPA authorizes the Department to compel generation only when an emergency shortage of electric energy would occur absent operation of Craig Unit 1 specifically.³⁰⁰ The Order’s terms fail to require operation “only during the

²⁹⁹ 16 U.S.C § 824a(c)(2) (emphasis added).

³⁰⁰ *Id.*; see, e.g., Department, [Order No. 202-17-4, Summary of Findings](#) (Sept. 14, 2017), at 9 (“authorizing operation of” units subject to emergency order “only when called upon . . . for reliability purposes,” according to “dispatch methodology” approved by Department).

hours necessary to meet the emergency” described by the Order and violates Section 202(c)(2) because the Order does not establish any limited hours or other parameters for Craig Unit 1 to follow.

The Order also contains no limitation on how SPP West and WACM may call on Craig Unit 1. By leaving the dispatch of Craig Unit 1 entirely in the hands of these entities, the Department is failing to properly limit operation as required by Section 202(c). Without a clearly defined emergency, WACM and SPP West have no standards to determine under what circumstances they should “require the continued operation of Craig Unit 1.” The premise for such continued operation is the energy “emergency” articulated in the Order, but it is impossible to know what conditions require Craig Unit 1 to operate by reading the Order.³⁰¹ Orders issued by the Department prior to 2025 demonstrate that the Department is capable of including appropriate limiting conditions in Section 202(c) orders. For example, in 2022, the Department issued an order in response to periods of extreme heat, drought conditions, and threat of wildfires that were expected to occur over several days and threaten the reliable operation of the bulk electric power system in California. That order directed the Balancing Authority of Northern California to dispatch specific units only “under the following conditions: the issuance and continuance of an Energy Emergency Alert Level[] 2 condition or greater between the hours of 14:00 Pacific Time and 22:00

³⁰¹ Indeed, the Order contains confusing and contradictory instructions regarding the unit’s operations, stating both that “Craig Unit 1 shall not be considered a capacity resource” and that its “continuous operation” is required. Exhibit A, at 1, ¶ G. Presumably, this means that the unit may only be called up by WAPA or SPP when there is an actual supply shortage that existing resources cannot meet. But if that is the intent, it is not clear from the face of the Order.

Pacific Time after exhausting all reasonably and practically available resources."³⁰²

Although Section 202(c)(2) requires the Department to include limiting conditions in the Craig Unit 1 Order as well, it chose not to, and that choice is contrary to law.

Second, Section 202(c)(2) requires that where an order may result in a conflict with environmental law or regulation, it must "to the maximum extent practicable, [be] consistent with any applicable Federal, State or local environmental laws." The Order contains no analysis of the plant's environmental obligations and no operational criteria established to minimize impacts. The Order merely states that "operations of Craig Unit 1 must comply with applicable environmental requirements to the extent feasible while operating consistently with emergency conditions."³⁰³

There are numerous environmental requirements that are affected by the continued operation of the Craig Unit 1 facility, but the Department failed to identify mechanisms to allow Craig Unit 1 to remain available while minimizing conflicts with these requirements. The Department also did not consult with the State of Colorado, including its environmental regulators, who could have advised on ways to minimize impacts.³⁰⁴ The Order does not reference or discuss the applicable environmental laws

³⁰² Department, [Order No. 202-22-2](#) (Sept. 4, 2002) at 4; see also [Letter from Kevin Kolevar, Director, Office of Electricity Delivery and Energy Reliability to Robert Driscoll, CEO, Mirant Mid-Atlantic, LLC](#) (May 31, 2007) (Letter from DOE describing the emissions limitations that a utility should follow when complying with a 202(c) order.); Department, [Order No. 202-17-1](#) (Apr. 14, 2017) (202(c) Order from DOE instructing SPP to adopt a temporary operating guide and comply with additional operating requirements set out in an EPA compliance order).

³⁰³ Exhibit A, ¶ C.

³⁰⁴ Exhibit B, ¶¶ 10, 32-34; see also Section 103 of the Department of Energy Organization Act, 42 U.S.C. § 7113 (requiring the Department to give due consideration to the needs of states when proposing any action that conflicts with a state energy plan, and to attempt to resolve conflicts through consultations with appropriate state officials). The Order plainly conflicts with Tri-State's decision-making process, the CoPUC's approved ERPs, the EPA-approved Regional Haze SIP, and AQCC regulation.

and regulations impacted by the Order, revealing the Department's failure to analyze these requirements to ensure compliance with environmental standards.

In particular, the Order fails to reflect any consideration of interactions with the Federal Clean Air Act Regional Haze program³⁰⁵ or National Ambient Air Quality Standards ("NAAQS") attainment and permitting programs. The Regional Haze program requires states to reduce emissions of NO_x, SO₂, and PM from sources that affect Class I federally protected areas.³⁰⁶ States must conduct detailed and expensive analyses, and based on the results of those analyses, impose federally enforceable controls and emission limits upon the largest and most impactful sources of haze pollutants.³⁰⁷ The Federal Clean Air Act, through the NAAQS attainment and permitting programs, also directs states to achieve and maintain air quality standards for certain pollutants, including NO_x, SO₂, and PM.³⁰⁸ The Department does not appear to have conducted any analysis of the impact keeping Craig Unit 1 operational may have on sources' and Colorado's ability to comply with either of these programs. The Order gives no guidance as to whether it creates conflicts with either of these requirements and, if it does, on how to navigate them.

³⁰⁵ EPA recently disapproved Colorado's Regional Haze Plan for Round 2 (which does not involve Craig Unit 1) by, in part, pointing to this Order. 91 Fed. Reg. at 3,049, fn. 9 (Jan. 26, 2026). While Colorado maintains that EPA's action was improper, and that its Regional Haze SIP currently meets federal requirements, it does reveal that EPA considers Craig Unit 1 relevant to Colorado's compliance with Regional Haze requirements now and in the future. The federal government must, but fails to, take a consistent position in the Regional Haze SIP disapproval and the Order as it relates to Craig Unit 1.

³⁰⁶ See 42 U.S.C. §§ 7491, 7492; see also implementing regulations at 40 C.F.R. § 51.300-309.

³⁰⁷ *Id.*

³⁰⁸ See, e.g., 42 U.S.C. §§ 7409, 7410.

Accordingly, the Order violates the Department's statutory obligation to "ensure" the maximum feasible compliance with applicable environmental standards.³⁰⁹ This obligation requires the Department to offer some discrete guidance as to the unit's operations, rather than merely parroting the statutory text. This lack of detail also makes it impossible for Colorado's environmental regulators to know what operational activities are excused from environmental compliance by the Order, increasing the complexity and burdens associated with any state enforcement actions.

Third, Section 202(c)(2) requires the Department to minimize the adverse environmental impacts of the Order, which the Order fails to do. This mandate is textually and substantively distinct from the Department's (also unfulfilled) obligation to ensure maximum practicable compliance with environmental standards. By failing to include a sufficient or legal description of the purported emergency, this Order authorizes Unit 1 to generate electricity and pollute beyond any emergency needs, thereby increasing the environmental impacts that by law the Order must minimize. When Craig Unit 1 operates, it emits NO_x, SO₂, fine PM, GHG emissions, HAPs, and other harmful pollutants.³¹⁰ The Order includes no measures to mitigate impacts when compliance with environmental standards proves impracticable, even though those types of measures have been routinely included in past orders.³¹¹ At a minimum, the

³⁰⁹ 16 U.S.C. § 824a(c)(2) (emphasis added).

³¹⁰ Exhibit B, ¶ 13.

³¹¹ See, e.g., Department, [Order No. 202-17-4](#) (Sept. 14, 2017) at 2 (permitting non-compliant operation only during specified hours, and requiring exhaustion of "all reasonably and practicably available resources," including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions); Department, Order No. 202-22-4 (Dec. 12, 2022) (requiring "reasonable measures to inform affected communities" of non-compliant operations).

statute requires the Department to include sufficiently detailed reporting obligations to ascertain what impacts result from emergency operations; without such reporting, the Department has no ability to “ensure” that adverse impacts are minimized.³¹² The Order here instead merely requires “such additional information” as the Department, in the future, may (or may not) “request[] . . . from time to time.” That possibility of future, unspecified information gathering cannot satisfy the statute’s demand that the Department “ensure” that its Order minimizes environmental impacts.³¹³

Similarly, the Order does not address or assess mechanisms to minimize the pollution from Craig Unit 1 that would or could be associated with its operation in response to the Order. It also does not address or assess the environmental impacts associated with the acquisition and transport of additional coal that may be necessary to facilitate Unit 1’s operation, and contains no limitations on the type of coal that may be used so as to minimize the impacts of any new emissions. Not all coal is inherently compatible with the units at the Craig Station, and depending on where new coal is sourced from, there could be significant emissions and costs associated with the distances required to import that coal.³¹⁴ Nor are these impacts addressed by the Department’s cursory instruction to Tri-State to comply with applicable environmental requirements “to the maximum extent feasible.” Because the Department made no attempt to address the requirements of Section 202(c)(2), the Order is unlawful.

³¹² See, e.g., Department, [Order No. 202-24-1](#) (Oct. 13, 2024) at 4-5 (requiring detailed data on emissions of pollutants).

³¹³ 16 U.S.C. § 824a(c)(2).

³¹⁴ Exhibit B, ¶¶ 32-33.

For these reasons, the Order fails to comply with the Department's obligations under Section 202(c)(2), and should be withdrawn.

F. The Order is designed to support the federal administration's policy goal of propping up the coal industry, making it an arbitrary and capricious pretext.

Agency action is arbitrary and capricious when it rests on a "pretextual" reason that is "incongruent with what the record reveals about the agency's priorities and decision-making process."³¹⁵ Agency decisions that feature "unjustifiable bias or partisanship are precisely the types of agency actions that 'would work a violation of the arbitrary-and-capricious standard.'"³¹⁶ Here, the record demonstrates that there is no evidence of an energy emergency within the meaning of Section 202(c) that would support issuance of the Order. Instead, the Order is a transparent attempt to favor the Trump administration's preferred energy source and revive the coal industry. Because the Order is pretextual and divorced from any actual emergency, the Order violates the law and must be withdrawn.

i. The Department's 2025 Section 202(c) orders demonstrate a pattern of arbitrary and capricious behavior designed to carry out a policy goal.

Over the course of 2025, the Department and the President have made clear that they are using Section 202(c) orders to prevent coal-fired generating plants from retiring, simply because the current administration prefers coal and other fossil fuel generation. On his first day in office, the President declared a "National Energy Emergency" and identified coal as one of his preferred energy resources.³¹⁷ The President later directed the Department to "streamline" its use of emergency orders,

³¹⁵ *Dep't of Commerce*, 588 U.S. at 785.

³¹⁶ *Level the Playing Field*, 961 F.3d at 464 (quoting *Hagelin v. FEC*, 411 F.3d 237, 242 (D.C. Cir. 2005)).

³¹⁷ [Exec. Order 14156](#), 90 Fed. Reg. 8,433, 8,434 (Jan. 20, 2025), Sec. 8(a).

explaining that his goal was to “revitaliz[e] America’s big beautiful coal industry to support grid stability and American jobs.”³¹⁸

Following these pronouncements, the Department has issued orders for nearly every coal plant scheduled to retire in 2025, all for the statutory maximum of 90 days. None of these orders meet the same criteria as previous orders issued pursuant to Section 202(c). Specifically, none were publicly requested by a utility;³¹⁹ none were based on an inability to comply with environmental laws; and none were responsive to or tailored to meet a specific, imminent, unexpected and temporary emergency. The Department Secretary Wright has confirmed that “[t]he goal [of the recent 202(c) orders] is to stop the political closure of coal plants.”³²⁰

For example, the Department’s recent order to keep R.M. Schahfer Plant Units 17 and 18 running ignores the fact that Unit 18 was in a forced outage from February 16, 2025 to June 23, 2025, and then again from July 9, 2025 until now. It is unclear how a plant that barely operated throughout 2025 and was not operational at the time the Department issued its Section 202(c) order could help in an alleged emergency. The Schahfer Plant Order also fails to describe an emergency, and in fact actually recognizes that there is anticipated to be a surplus of generation capacity in

³¹⁸ The White House, [Fact Sheet: President Donald J. Trump Strengthens the Reliability and Security of the United States Electric Grid](#) (Apr. 8, 2025); see also New York Times, [Trump Signs Orders Aimed at Reviving a Struggling Coal Industry](#), April 8, 2025); Exec. Order 14261, [Reinvigorating American’s Beautiful Clean Coal Industry and Amending Executive Order 14241](#), 90 Fed. Reg. 15,517 (April 14, 2025); Exec. Order 14260, [Protecting American Energy from State Overreach](#), 90 Fed. Reg. 15,513 (April 14, 2025); [Regulatory Relief for Certain Stationary Sources To Promote American Energy](#), 90 Fed. Reg. 16,777 (April 21, 2025).

³¹⁹ It is common practice for the Department to post the request of the entity requesting a specific order within that order’s docket. See, e.g. Department, [2024 DOE 202\(c\) Orders](#); Department, [2023 DOE 202\(c\) Orders](#).

³²⁰ Department, [Energy Department Convenes First National Coal Council Meeting Under Renewed Charter, Reaffirming Coal’s Role in Unleashing American Energy](#) (Jan. 15, 2026).

MISO's 2025-2026 winter season,³²¹ revealing that order, like the Order, to be incongruent with the record facts.³²²

Together, these orders demonstrate that, rather than addressing emergencies, the Department is working to prevent the retirement of coal plants across the United States.

ii. Despite claims it is addressing energy emergencies, the Department is simultaneously interfering with efforts to increase generation through renewable resources.

At the same time the Department is claiming that an energy emergency justifies exercise of its Section 202(c) emergency authority, it is also working to stymie development of renewable generation sources, particularly wind and solar.

The Department's own website explains that "wind energy offers many advantages which explains why it's one of the fastest-growing energy sources in the world[.]"³²³ and that solar energy "can support household savings, energy independence, economic opportunities, grid reliability, resilience, security and affordability, and a safer planet."³²⁴ Wind and solar energy are also extremely cost competitive with other energy sources. The most recent Levelized Cost of Energy+ Report ("LCOE Report") found that "[o]n an unsubsidized \$/MWh basis, renewable energy remains the most cost-competitive form of generation."³²⁵ Renewables are also important in a high demand scenario, as they are the "quickest-to-deploy

³²¹ Exhibit S, at 3.

³²² See *Dep't of Commerce v. New York*, 588 U.S. at 785.

³²³ Department, [Advantages and Challenges of Wind Energy](#).

³²⁴ Department, [Solar Energy](#).

³²⁵ Lazard LCOE, [Levelized Cost of Energy+](#) (June 2025), at 4.

generation resources.”³²⁶ Colorado has confirmed that wind and solar energy are low cost options to provide reliable electricity generation in the Northwest Colorado region, including Craig.³²⁷

Despite these advantages, the federal government and the Department have been actively repressing wind, solar, and hydrogen fuel deployment. Alongside the Energy Emergency Executive Order, President Trump issued an executive memorandum (“Memo”) directing federal agencies to pause the issuance of all wind energy authorizations.³²⁸ That Memo has since been declared unlawful and vacated.³²⁹ In addition, the One Big Beautiful Bill Act ended subsidies for wind and solar energy projects years earlier than planned.³³⁰ The Department has also cut funding for grants that were supposed to go to projects such as hydrogen technology and upgrades to the electric grid.³³¹ And although the solar industry installed nearly 18 GW of new

³²⁶ *Id.*

³²⁷ See Colorado Energy Office, [Exploring Advanced Energy Solutions for Rural Colorado](#) (Dec. 19, 2025) (study looked at both the levelized cost of energy and the levelized cost of capacity for multiple generation options and found that solar combined with battery storage has the lowest levelized cost of electricity, and wind combined with battery storage has the lowest cost levelized net cost of capacity).

³²⁸ Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government’s Leasing and Permitting Practices for Wind Projects, 90 Fed. Reg. 8,363 (Jan. 29, 2025).

³²⁹ [Judgement Ordered 12/18/2025](#) in *State of New York v. Trump*, 25-cv-11221-PBS (D. Mass.).

³³⁰ Sidley, [The “One Big Beautiful Bill” Act - Navigating the New Energy Landscape](#) (Jul. 15, 2025); see also 26 U.S.C.A. § 45Y (creating wind production tax credits, passed Aug. 2022); 26 U.S.C.A. § 48E (creating solar investment tax credits, passed Aug. 2022); One Big Beautiful Bill Act, Pub. L. 119-21, Title VII, § 70512-3, 139 Stat 72 (July 4, 2025) (amending 26 U.S.C.A § 45Y and 26 U.S.C.A. § 48E to end subsidies for wind and solar projects).

³³¹ See Walton, R., [DOE cancels \\$7.6B in clean energy awards in states that voted against Trump](#) (Oct. 2, 2025); Banse, T., [Trump administration yanks funding for Northwest green hydrogen project](#) (Oct. 2, 2025); Kaufman, A., [Trump’s cuts to billion-dollar hydrogen hubs rattle industry](#) (Oct. 2025).

capacity in the first half of 2025, the federal administration's efforts to stymie wind and solar energy has resulted in significantly reduced solar deployment.³³²

As the Department has observed, "the reliability of the power grid is intrinsically a system-wide property that cannot be ensured by an individual resource or technology in that system."³³³ Focusing on one technology instead of a portfolio of resource adequacy measures increases risk.³³⁴ The Department's current single-minded focus on coal reflects a policy preference as opposed to a desire to address any actual energy emergency, and constitutes an unlawful pretext.

G. The Department failed to comply with NEPA.

By requiring Craig Unit 1 to remain available beyond its planned retirement date, the Order has the potential to cause significant environmental impacts and requires evaluation under NEPA.³³⁵ Because the Department has misused its emergency authority in the Order,³³⁶ it cannot rely on the exception to NEPA's implementing procedures that applies to emergency actions. Quite simply, there is no "emergency situation[] that demand[s] immediate action" here.³³⁷ As demonstrated above, there is no current or imminent energy shortfall or near-term reliability emergency that justifies continued operation of Craig Unit 1.³³⁸ Accordingly, to the

³³² Wood Mackenzie, [Solar and storage dominate new power additions in first six months of Trump administration as federal policies drive up energy costs](#) (Sept. 9, 2025); Economy+Environment, [Clean Economy Works: November 2025 Analysis](#) (Dec. 12, 2025).

³³³ Department, [The Future of Resource Adequacy](#) (Apr. 2024) at 8.

³³⁴ *Id.*

³³⁵ 42 USC 4336(b), *supra*.

³³⁶ See Sections V.A-F, *supra*.

³³⁷ 10 C.F.R. § 1021.103.

³³⁸ See Section V.C., *supra*.

extent the Department is relying on the exception for emergency actions to avoid full NEPA analysis, such reliance is contrary to law.

Moreover, the Department's NEPA implementing regulations recognize that where an action has the potential to cause significant impacts on an environmentally sensitive area, such as federally- and state-designated wilderness areas, national parks, scenic areas, and similar resources, the action is not appropriate for categorical exclusion and instead must be analyzed under NEPA.³³⁹ Here, retirement of Craig Unit 1 by December 31, 2025 is a requirement of Colorado's federally approved SIP to address the Federal Clean Air Act visibility program. This program is designed to protect federally-designated areas home to sensitive ecosystems or species potentially harmed by even small increases in pollution.³⁴⁰ Specifically, the Colorado Regional Haze SIP, which incorporated Craig Unit 1's retirement date in Round 1, is designed to protect national parks and wilderness areas in Colorado including Black Canyon of the Gunnison National Park, Great Sand Dunes National Park, Rocky Mountain National Park, and Mount Zirkel Wilderness Area.³⁴¹ Craig Unit 1 is located near the Mount Zirkel Wilderness Area.³⁴² As a result, the Department's own NEPA regulations dictate that the action was subject to NEPA review.

³³⁹ 10 C.F.R. Part 1021, Appx. B, § B(4)(iv).

³⁴⁰ Exhibit B, ¶ 26.

³⁴¹ Exhibit MM (Division, *Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)).

³⁴² 5 Colo. Code Regs. § 1001-5:F.VI. (2014).

VI. Request For Stay

In addition to seeking rehearing, the State of Colorado moves the Department for a stay of the Order until the conclusion of judicial review.³⁴³ The Department should also refrain from renewing the Order as currently drafted beyond its current expiration in March 2026. The Department has the authority to issue a stay under the Administrative Procedure Act and should do so where “justice so requires.”³⁴⁴ In deciding whether to grant a request for stay, agencies consider: (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest.³⁴⁵

Injuries under this standard must be actual, certain, imminent, and beyond remediation.³⁴⁶ Financial injury is irreparable where no “adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation.”³⁴⁷ Environmental injury, however, “can seldom be adequately remedied by money damages and is often permanent or at least of long duration, *i.e.*,

³⁴³ 18 C.F.R. § 385.212.

³⁴⁴ 5 U.S.C. § 705.

³⁴⁵ See *Nken v. Holder*, 556 U.S. 418, 434, 436 (2009); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); see, e.g., *Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,020, at P 41 (2023); *ISO New Eng. Inc.*, 178 FERC ¶ 61,063, at P 13 (2022), *rev'd on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987-88 (D.C. Cir. 2022).

³⁴⁶ *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at p. 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at p. 61,795 (1999) (recognizing that, absent a stay, options for “meaningful judicial review would be effectively foreclosed”).

³⁴⁷ *Wis. Gas Co.*, 758 F.2d at 674 (quoting *Va. Petroleum Jobbers Ass'n v. Fed. Power Comm'n*, 259 F.2d 921, 925 (D.C. Cir. 1958)); see also *In re NTE Conn., LLC*, 26 F.4th at 990-91. (Colorado refuses to concede that its residents, as ratepayers, should bear this cost of the Department’s illegal actions here. Nonetheless, we assume that neither the Department nor the Craig Station owners want to bear those costs either, and will seek to impose them on Coloradans.)

irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an injunction to protect the environment.”³⁴⁸

A. Colorado and its people will suffer irreparable injury absent a stay.

Here, a stay is necessary to prevent irreparable harm to the State of Colorado. If Craig Unit 1 is required to operate, it will result in emissions of dangerous air pollutants that would not otherwise have occurred but for the Order. And even requiring Craig 1 to be available to operate, as the Order directs, will increase costs that may be passed on to ratepayers, along with increasing pollution directly through readying activities, and indirectly through the sourcing and transportation of fuel. Even if the unit dispatches rarely or not at all, these excess pollutants contribute to and exacerbate respiratory problems, cardiovascular issues, and other health conditions.³⁴⁹

A stay would not result in harm to any other interested parties. The issuance of a stay would not harm end-use electricity consumers because there is no emergency addressed by the operation of Craig Unit 1. The lack of an actual emergency means that a stay would not disrupt the provision of electricity. Furthermore, because Tri-State had already planned for the closure of Craig Unit 1, a stay would have the effect only of relieving Tri-State of the administrative, compliance, and planning burdens imposed by the Order. On the balancing of equities, there is therefore no meaningful countervailing harm that would follow from a stay.

³⁴⁸ *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).

³⁴⁹ Exhibit B, ¶ 21.

B. A stay is in the public interest.

There is no public interest served by the Order, and a stay will only benefit the public. First, the Order exceeds the Department's authority; it has provided no reasonable grounds to substantiate any near-term or imminent shortfall in electricity supply that would necessitate Craig Unit 1's continued operation.³⁵⁰ Second, a stay would protect the broader public from the costs and additional pollution produced by unnecessary operation of Craig Unit 1.

VII. Conclusion

For the reasons set forth above, the State of Colorado respectfully requests that the Department grant intervention; grant a rehearing and rescind the Order; and stay the Order.

Filed on January 28, 2026.

Submitted by:
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³⁵⁰ See *League of Women Voters v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (noting that "there is a substantial public interest 'in having governmental agencies abide by the federal laws that govern their existence and operations'") (quoting *Washington v. Reno*, 35 F.3d 1093, 1103 (6th Cir. 1994)).

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Certificate of Service

This is to certify that I have duly served the foregoing, **The State Of Colorado's Request For Rehearing, Motion to Intervene, and Stay Request**, upon all parties below electronically via e-mail this 28th day of January, 2026:

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State of Colorado's Exhibit List

Exhibit No.	Document Description
A	Department, Order No. 202-25-14 (Dec. 30, 2025)
B	Declaration of Josh Korth Declaration (Jan. 26, 2025)
C	Declaration of Erin O'Neil (Jan. 26, 2025)
D	Declaration of Joseph Pereira (Jan. 23, 2025)
E	CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E.
F	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-2 (Tri-State, 2020 IRP/ERP, Public (Dec. 1, 2020)
G	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1 (Tri-State, <i>Responsible Energy Plan</i> (Jan. 2020)
H	Salt River Project, <i>2023 Integrated Systems Plan</i>
I	Department, Order No. 202-25-7 (Aug. 20, 2025)
J	CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E
K	NERC, <i>2024 Long-Term Reliability Assessment</i> (Dec. 2024)
L	NERC, <i>2025-2026 Winter Reliability Assessment</i> (Nov. 2025)
M	Department, <i>Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid</i> (July 2025)
N	Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York, filed on August 6, 2025 with the Department
O	Department, Order No. 202-25-3 (May 23, 2025)
P	Department, Order 202-25-4 (May 30, 2025)
Q	Department, Order No. 202-25-11 (Dec. 16, 2025)
R	Department, Order No. 202-25-13 (Dec. 23, 2025)
S	Department, Order No. 202-25-12 (Dec. 23, 2025)
T	Congressional Research Service, <i>Federal Power Act: The Department of Energy's Emergency Authority</i> (June 12, 2025)
U	Department, Order 202-25-9 (Nov. 18, 2025)
V	Department, Order No. 202-25-8 (Aug. 28, 2025)
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
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)

Y	CoPUC, <i>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</i> , filed on November 10, 2025, in Proceeding No. 25V-0480E
Z	CoPUC, <i>Tri-State, 2025 Annual Progress Report</i> , filed on December 1, 2025, in Proceeding No. 23A-0585E
AA	CoPUC, Decision No. R24-0602, issued on August 22, 2024, in Proceeding No. 23A-0585E
BB	CoPUC, Decision No. C25-0892, issued on December 10, 2020, in Proceeding No. 25V-0480E
CC	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-Attachment F (<i>Electric Energy and Demand Forecast, Public</i>)
DD	CoPUC, Hrg. Ex. 103, Direct Testimony and Attachments of Brian L. Thompson, Rev. 1, filed on May 24, 2024, in Proceeding No. 23A-0585E
EE	PRPA, <i>2024 Integrated Resource Plan (Apr. 2023)</i>
FF	PRPA, <i>Craig Units 1&2 (Yampa Project) (2026)</i>
GG	PacifiCorp, <i>Utah Integrated Resource Plan Volume I (Mar. 31, 2025)</i>
HH	SPP, <i>SPP Reliability Plan (Jun 2, 2025)</i>
II	NERC, <i>Emergency Operations</i>
JJ	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E
KK	Division, <i>Operating Permit No. 96OPMF155 (July 1, 2021)</i>
LL	Division, <i>Technical Review Document for Operating Permit 96OPMF155 (Jan. 2005)</i>
MM	Tri-State, <i>General APEN- Form APCD-200 (Apr. 21, 2025)</i>
NN	Division, <i>Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado (Dec. 15, 2016)</i>
OO	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 - Attachment G-1 (<i>Astrape Consulting, Reserve Margin and Effective Load Carrying Capability (ELCC) Study, Public (Aug. 2, 2023)</i>)
PP	Department, Order No. 202-25-10 (Nov. 25, 2025)
QQ	Tri-State, <i>U.S. DOE Orders TriState to Keep Craig Generating Station Unit Operating for Next 90 Days (Dec. 31, 2025)</i>
RR	Powell, R., <i>1 coal plant open amid order (Jan. 6, 2026)</i>
SS	Behr, P., <i>PJM to ratchet down projected AI power demand for eastern US (Jan. 6, 2026)</i>

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit D: Declaration of Joseph Pereira (Apr. 24, 2026)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

ORDER NO. 202-26-21

DECLARATION OF JOSEPH PEREIRA

I, Joseph Pereira, declare under penalty of perjury pursuant to 28 U.S.C. § 1746, that the following is true and correct to the best of my knowledge:

1. I am a resident of the State of Colorado. I am over the age of 18 and have personal knowledge of all the facts stated herein, except to those matters stated upon information and belief; as to those matters, I believe them to be true. If called as a witness, I could and would testify competently to the matters set forth below.

2. As Director of the Colorado Office of the Utility Consumer Advocate (“UCA”), I submit this declaration in support of the State of Colorado’s Request for Rehearing (“Request”) of the Department of Energy’s (“Department”) March 30, 2025 Order No. 202-26-21 (“Renewed Order”) regarding a coal-fired generating unit (“Craig Unit 1”) at the Craig Station facility in Craig, Colorado.

Personal Background and Qualifications

3. I have served as the Director of the UCA since March 2026. Prior to that I served as Deputy Director of the office beginning in 2019.

4. I received my Bachelor’s Degree in Public Policy from Metropolitan State University and conducted graduate work at the Center for Energy and Environmental

Policy at the University of Delaware. I also received training in regulatory studies at the Institute of Public Utilities at Michigan State University.

5. Prior to my work at UCA, I served as Regulatory Director at the Citizens Utility Board of Minnesota, advocating for consumers in utility resource acquisition, resource planning, distribution system planning, vehicle electrification, performance-based ratemaking, and other topics. I also served as the Director of Low-Income and Residential Energy Services at the Colorado Energy Office, where I oversaw policy, programs and regulatory activities related to residential and low-income utility customers.

6. As UCA Director, I am responsible for managing the office's statutory mandate to represent the public interest and, to the extent consistent with the public interest, the specific interests of residential, agricultural, and small business utility consumers by appearing in State and federal proceedings which may have an impact on utility rates.¹

7. In evaluating the public interest, the UCA gives due consideration to Colorado's grid reliability, statutory decarbonization goals, a just transition for the State's coal communities and workers, environmental justice, and the short- and long-term effect of the proceeding upon various classes of consumers.²

¹ § 40-6.5-104(1), Colo. Rev. Stat.; § 40-6.5-106(2)-(2.5), Colo. Rev. Stat.

² § 40-6.5-104(2), Colo. Rev. Stat.

8. UCA takes an active role in ensuring that Colorado’s State energy policy is implemented in a way that furthers the public interest. UCA’s advocacy at the State level regularly provides a consumer-focused perspective on costs, reliability, and keeping utilities on track to meet the State’s climate goals. UCA intervened and advocated for the public interest in Tri-State Generation and Transmission Association, Inc.’s (“Tri-State”) most recent Electric Resource Plan (“ERP”).³

Department of Energy Renewed Order

9. I am familiar with and have fully reviewed the Department’s Renewed Order regarding Craig Unit 1.

10. The Renewed Order’s directions that: 1) the co-owners of Craig Unit 1 shall take all measures necessary to ensure it is available to operate; and 2) Southwest Power Pool (“SPP”) take every step to employ economic dispatch of Craig Unit 1, run counter to the public interest in Colorado. The Initial Order No. 202-25-14 (“Original Order”) has increased—and the Renewed Order is likely to continue increasing—costs for Colorado’s rural electric cooperative customers, and they inject uncertainty into Colorado’s established long-term electric resource planning process. From a reliability perspective, continued operation of Craig Unit 1 is not necessary and not in the public interest. From a consumer cost perspective, continued operation of Craig Unit 1 is not in the public interest.

³ CoPUC, Proceeding No. 23A-0585E.

Consumer Costs

11. Craig Unit 1’s retirement, justified primarily by economics, has been anticipated by Tri-State, PacifiCorp, Platte River Power Authority, Salt River Project, and Public Service Company of Colorado (“Public Service”) (together, “Craig Unit 1 Owners”), and the State of Colorado since 2016.⁴ All of the electric resource planning performed since then by Craig Unit 1’s Owners and the other public utilities in Colorado has assumed Craig Unit 1 would cease operations at the end of 2025. For Tri-State specifically, the Colorado Public Utilities Commission (“CoPUC”) found in August 2025 that “Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record of [Tri-State’s most recent] ERP.”⁵

12. The Renewed Order fails to recognize that utility consumers have already paid—and are currently paying—for the approved plans and investments that Craig Unit 1’s Owners have determined are necessary to safely retire Craig Unit 1 while maintaining adequate reliability. Because of the Renewed Order, consumers who have been paying for Craig Unit 1’s replacement generation will also be forced to pay for expensive, excess generation that was not requested by the Craig Unit 1 Owners and is not necessary.

13. Craig Unit 1’s high costs can be attributed to its high fuel cost and low efficiency. Economic justification for Craig Unit 1’s retirement is supported by a recent analysis performed by Grid Strategies.⁶ According to that study, it is likely to

⁴ Tri-State, [Craig Station owners, regulators and environmental groups reach agreement on proposed revisions to Colorado regional haze plan](#) (Sept. 1, 2016).

⁵ Exhibit E (CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E), ¶ 116.

⁶ Grid Strategies, [The Economic Cost of a DOE Mandate for the Craig Unit 1 Coal-Burning Generator to Continue Operating](#) (Dec. 2025).

cost approximately \$20 million in fuel, operations, and maintenance costs to continue operating Craig Unit 1 for the 90-day effective period of the Renewed Order. The study estimates that on an annual basis, Craig Unit 1 will cost approximately \$85 million to operate. This estimate does not account for deferred maintenance which is required to keep Craig Unit 1 available to operate, undertaken when Tri-State believed the plant would retire at the end of 2025; it also does not account for additional expenditures that may now be necessary for a plant that began operating in 1980 and is likely nearing the end of its operational life.

14. In response to the Original Order issued by the Department on December 30, 2025, Tri-State said that “retaining [Craig] Unit 1 will likely require additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs.”⁷

15. As illustrated by the analysis performed by Grid Strategies, operating Craig Unit 1 is likely to cost more in the future than it did in the past. This is due to increasing operations and maintenance costs, repair costs for the mechanical failure, and other additional investments that will be necessary to extend the life of Craig Unit 1.

16. As the operator of Craig Unit 1, Tri-State will incur higher costs to serve its member utility cooperatives. Some of these costs have already been—and will continue to be—passed on to rural electrical cooperative consumers. According to Tri-

⁷ Exhibit QQ (*Tri-State*, U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days (Dec. 31, 2025)) at 2.

State's Chief Executive Officer Duane Highley at the time the Original Order was issued:

As a not-for-profit cooperative, our membership will bear the costs of compliance with this order unless we can identify a method to share costs with those in the region. There is not a clear path for doing so, but we will continue to evaluate our options.⁸

17. Based on my experience and familiarity with Colorado's ERP process and UCA's participation in the State's orderly retirement of coal-fired electricity generating stations, I can conclude that the Renewed Order is not in the public interest for the State of Colorado because it has imposed unnecessary costs on rural electricity consumers and it is likely to continue to raise rates for a substantial portion of Colorado's electricity consumers.

I declare under penalty of perjury that, to the best of my knowledge, the foregoing is true and correct.

Executed this 24th day of April, 2026.

Joseph Pereira

Joseph Pereira

⁸ *Id.* at 3.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit DD: CoPUC, Hrg. Ex. 103, Direct Testimony and Attachments of Brian L.
Thompson, Rev. 1, filed on May 24, 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
BRIAN L. THOMPSON
ON BEHALF OF
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.**

December 1, 2023

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BLT-1	Statement of Qualifications for Brian L. Thompson
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1 **I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY**

2 **Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A: My name is Brian Thompson. My business address is 1100 West 116th Avenue,
4 Westminster, CO 80234.

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

6 A: I am employed by Tri-State Generation and Transmission Association, Inc. ("Tri-
7 State") as Resource Planning Manager.

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

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

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

12 A: Yes. My Statement of Qualifications is attached to my testimony as **Attachment**
13 **BLT-1.**

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

16 A: I have 16 years of experience in the electric utility industry. I manage the resource
17 planning group at Tri-State. We are responsible for short-term and long-term
18 modeling of the Tri-State system, including scenario and portfolio modeling
19 associated with the ERP/IRP process. Previously, I held the following positions at
20 Tri-State: Associate Real Time Marketer, Senior Energy Portfolio Analyst, Term
21 Marketer, and Senior Engineer Resource Planning. I have a Bachelor of Science
22 in Manufacturing Engineering Technology from Brigham Young University.

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

2 A: My testimony addresses the 2023 Electric Resource Plan (“ERP”) model set-up
3 based on the Tri-State system topology and key data input assumptions for Tri-
4 State’s Phase I ERP, including generic resource parameters, as well as
5 summarizes third-party study results.

6 **Q: ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR DIRECT**
7 **TESTIMONY?**

8 A: Yes, as part of my Direct Testimony, I am sponsoring the following attachments:

- 9
 - Attachment BLT-1: Statement of Qualifications for Brian L. Thompson

10 **II. TRI-STATE’S APPROACH TO MODELING**

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

12 A: In this section of my Direct Testimony, I describe the systems and analytical
13 methodologies utilized by Tri-State to develop its 2023 ERP, including the
14 modeling software used for expansion plan and dispatch modeling.

15 **Q: WHAT MODELING TOOL IS BEING USED IN THE 2023 ERP?**

16 A: Tri-State is continuing to use EnCompass software for the 2023 ERP, which was
17 also utilized for Phase II of the 2020 ERP.

18 **Q: PLEASE DESCRIBE THE SYSTEMS AND ANALYTICAL METHODOLOGIES**
19 **EMPLOYED TO DEVELOP THE 2023 ERP.**

20 A: The ERP Report (**Attachment LKT-1**) describes the systems Tri-State utilized for
21 modeling the 2023 ERP and it also identifies the flow of input and output data
22 between each system. As stated above, Tri-State utilizes EnCompass software
23 for the expansion plan and dispatch modeling, as was done for Phase II of the

1 2020 ERP. The modeling setup is reflective of Tri-State’s four-state system and
2 location of our generation, load pockets, markets, transmission availability and
3 constraints, and power flows between regions (visually represented in **Attachment**
4 ~~**B-6** of the ERP Report (**Attachment LKT-1**)~~ **LKT-13**). The system topology is largely
5 similar to what was modeled in Phase II of the 2020 ERP, with three updates:

- 6 • Assumed energy transfer capability from the Eastern Colorado (“ECO”) to
7 New Mexico (“NM”) planning regions was modified from 200 MW to 191
8 MW.
- 9 • 100 MW of energy transfer capability, at an incremental cost of \$8.06/MWh,
10 was added from the NM to the ECO planning region.
- 11 • 76 MW of energy transfer capacity, at an incremental cost of \$2.39/MWh,
12 was added from the ECO to Western Colorado (“WCO”) planning region.

13 In addition to the base modeling set-up to reflect the Tri-State system, numerous
14 financial, operational, and environmental data assumptions are input into the
15 model. Once the topography design and all input assumptions are input and tested
16 in EnCompass, scenario modeling can begin.

17 **Q: PLEASE PROVIDE AN OVERVIEW OF TRI-STATE’S RESOURCE PLAN**
18 **SCENARIO MODELING PROCESS.**

19 A: Tri-State models several resource plan scenarios. Each scenario is grounded in
20 the base modeling assumptions, but with unique modeling assumptions applied as
21 identified in **Attachment B-3** of the ERP Report (~~**LKT-1**~~) **LKT-10**. In the first step, the
22 model output results in an optimal expansion plan, which includes selected new
23 generation needs, selected unit retirements, and levels of demand-side

1 management. In the second step, the model dispatches the generation to meet
2 load across the planning period based on the given expansion plan, existing
3 resources, and system constraints. The 8760 dispatch run results in modeling
4 outputs such as forecasted unit capacity factors, market sales and purchases,
5 energy required, curtailments, unit starts, heat required, fuel costs, and
6 transmission flows. The expansion plan and dispatch outputs are analyzed by Tri-
7 State's financial and transmission planning teams to assess the forecasted
8 financial impact of the generation and transmission requirements of each scenario.

9 **Q: HOW MANY SCENARIOS DID TRI-STATE MODEL?**

10 A: Tri-State modeled five scenarios. Each scenario reflected the base modeling
11 assumptions, but with alterations to the assumptions based on Tri-State and
12 stakeholders' desired parameters. The modeling of each scenario results in a
13 unique expansion plan, dispatch, and financial result for each scenario. Following
14 the completion of each scenario modeling run, the scenarios were tested and
15 analyzed to evaluate their performance under two sensitivity conditions. A
16 sensitivity analysis maintains the same expansion plan (i.e., generation units
17 available to meet load in a given year) but modifies assumptions about the system
18 operational environment (e.g., weather, prices) to test the performance of a
19 scenario under potential hardship circumstances that could arise. I discuss the
20 details of modeling sensitivities further below.

21 **Q: WHAT ARE SOME OF THE PRIMARY DATA INPUTS FOR SCENARIO**
22 **MODELING?**

23 A: Data inputs fall into three core categories: 1) operational/technical, 2) financial, and

1 3) environmental. Some of the primary data inputs for scenario modeling include:

- 2 • Operational/Technical: load forecast, transmission constraints, outage
3 rates, Electric Load Carrying Capability (“ELCC”), contracts, operational
4 data related all resources, demand-side management and beneficial
5 electrification potential, etc.
- 6 • Financial: capital expenditure forecast, operations and maintenance
7 (“O&M”) forecast, generic resource pricing, forward pricing of power and
8 gas curves, etc.
- 9 • Environmental: carbon emission limits.

10 These are a sampling of the numerous data inputs that are included in the
11 model. A list of all modeling assumptions can be found in **Attachment B** of the
12 ~~ERP Report (LKT-1)~~ **LKT-7**.

13 **Q: PLEASE IDENTIFY THE MOST SIGNIFICANT UPDATES TO MODELING**
14 **INPUT ASSUMPTIONS FOR THE 2023 ERP.**

15 **A:** Tri-State reviews all of the operational, financial, and environmental data inputs to
16 assess the need for updates or modification based on current operating conditions
17 and policy requirements. The significant modeling modifications of note include:

- 18 • Planning Reserve Margin (“PRM”) adjustment, starting at 22% and
19 transitioning to 30.5% after Craig 3 retires;
- 20 • Updated ELCC values for wind, solar, and storage, and capacity credit for
21 thermal units;
- 22 • Updated load forecast that removes exiting Members’ loads and loads to be

- 1 served through Partial Requirements;
- 2 • Numerous updated financial assumptions, such as decommission cost,
- 3 generic resource pricing, fixed and variable O&M costs, and the forecast of
- 4 capital expenditures; and
- 5 • Inclusion of several new innovative technologies not previously modeled by
- 6 Tri-State for the model to evaluate.

7 **Q: WHAT OUTPUTS RESULT FROM THE ERP MODELING FOR EACH**

8 **SCENARIO?**

9 A: Through the modeling, we are able to forecast our resource mix, new resource

10 additions, financial and environmental impacts, and the level of reliability achieved

11 by each scenario, among other outputs. The modeling results for each scenario

12 are shown in the ERP Report (LKT-1).

13 **III. STUDIES SUPPORTING TRI-STATE'S PHASE I MODELING**

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

15 A: In this section of my Direct Testimony, I provide a description of the third-party

16 studies and analyses supporting the 2023 ERP Phase I.

17 **Q: PLEASE PROVIDE AN OVERVIEW OF THE STUDIES SUPPORTING TRI-**

18 **STATE'S PHASE I MODELING.**

19 A: There were four studies completed to inform Tri-State's 2023 ERP modeling, these

20 include:

- 21 • Benchmarking Analysis: This study was completed by Black & Veatch in
- 22 October 2023. It compares existing resources and generic resources, in
- 23 regard to cost and performance. This study is provided as **Attachment G-**

LKT-30

- 1 ~~2 of the ERP Report (LKT-1).~~
- 2 • ELCC and PRM Study: Tri-State engaged Astrape to perform an ELCC
- 3 Study for establishing ELCCs for solar, wind, and storage at various
- 4 penetration levels, and capacity credits for thermal resources, as well as for
- 5 establishing an appropriate PRM. This study was completed in August
- 6 2023 and is provided as ~~Attachment G-1 of the ERP Report (LKT-1).~~ LKT-29
- 7 • IRA Scenario Reliability Evaluation: Astrape performed a supplemental
- 8 analysis of the IRA Scenario’s reliability in year 2032 of the planning period.
- 9 This analysis is provided as ~~Attachment G-4 of the ERP Report (LKT-1).~~ LKT-32
- 10 • DSM Potential Study and BE Potential Study: Mesa Point updated the 2020
- 11 Potential Studies in May 2023 to refresh the level of Demand-Side
- 12 Management (“DSM”) energy savings and beneficial electrification (“BE”)
- 13 potential within the Tri-System resulting from the exit of three Members from
- 14 the system, updated equipment use and saturations, as well as updated
- 15 avoided costs, emissions rates, and social cost of carbon. This study is
- 16 provided as ~~Attachment G-3 of the ERP Report (LKT-1).~~ LKT-31

17 **a. Benchmarking Analysis**

18 **Q: PLEASE DESCRIBE THE BENCHMARKING ANALYSIS.**

19 A: Tri-State engaged Black & Veatch (“B&V”) to perform an analysis of cost and

20 performance of existing owned resources, contracted resources, and generic

21 resources. The study provides a resource ranking for each existing and generic

22 resource, with and without sunk costs. Key insights from the B&V’s Benchmarking

23 Analysis include:

- 1 • On a Levelized Cost of Energy (“LCOE”) basis, wind and solar PPAs and
2 build-transfers, and pumped storage resources are the lowest cost;¹ and
3 • On a Levelized Cost of Capacity (“LCOC”) basis, simple cycle combustion
4 turbine resources are the lowest cost.²

5 Not surprisingly, the study acknowledges that sunk costs (depreciation,
6 decommissioning, etc.) are a significant driver in the cost-effectiveness of Tri-State
7 owned resources.³

8 **Q: HOW DO THE RESULTS OF THE BENCHMARKING ANALYSIS INFORM TRI-**
9 **STATE’S ERP APPLICATION?**

10 A: The Benchmarking Analysis identifies the levelized cost of each resource in Tri-
11 State’s fleet, as well as the levelized cost of potential new generic resources to be
12 added to our fleet and identifies how they perform in comparison to one another.
13 These results offer the opportunity for Tri-State to assess which units are out-
14 performing others, based on certain factors. While the benchmarking results are
15 informative, resource plan modeling is able to take into consideration a number of
16 key assumptions, including environmental and transmission constraints which
17 ensures a comprehensive approach to resource planning analysis.

18 **b. ELCC and PRM Study**

19 **Q: PLEASE DESCRIBE THE ELCC COMPONENT OF THE ASTRAPE STUDY.**

20 A: The Astrape study determines the appropriate ELCCs for solar, wind and battery

¹ Attachment G-2, pg. 10. LKT-30
² Attachment G-2, pg. 11. LKT-30
³ Attachment G-2, pg. 12. LKT-30

1 storage resources on the Tri-State system given an anticipated resource mix, and
2 capacity credits for thermal units. Applying appropriate ELCCs, represented as a
3 percent of nameplate capacity, enables calculation of the amount of dependable
4 capacity that can be counted on by the system for resource adequacy purposes.
5 The primary result of ELCC Study is a three-dimensional matrix of portfolio
6 capacity values from which average and marginal ELCCs can be determined for
7 any level of penetration of solar, wind, and batteries. Astrape provided Tri-State
8 ELCCs for Tri-State's anticipated resource mix but also provided a tool to enable
9 calculation of the average and marginal ELCCs for a given penetration level of
10 solar, wind, and batteries in each scenario modeled in the event any scenario
11 deviated substantially from the anticipated mix.

12 **Q: HOW IS THE ELCC METHODOLOGY USED IN TRI-STATE'S PHASE I**
13 **MODELING?**

14 A: As resource penetrations increase over time, the technology-specific ELCCs
15 decline. The appropriate ELCC is applied in EnCompass for each existing and
16 new generating unit based on the level of installed capacity of the technology, as
17 shown in **Table BLT-D-1**. The ELCC values result from the Astrape Study.

1

Table BLT-D-1. ELCC Values for 2023 ERP Phase I

Solar		Wind		4-hour Batteries	
Levels (MW)	ELCC	Levels (MW)	ELCC	Levels (MW)	ELCC
0 to 820	5%	0 to 790	17%	0 to 100	97%
821 to 1200	3%	791 to 1200	10%	101 to 200	89%
1201 to 1600	3%	1201 to 1600	9%	201 to 400	65%
1601 to 2000	1%	1601 to 2000	6%	401 to 800	45%

2

3 **Q: DID TRI-STATE PREVIEW THE ELCC METHODOLOGY AND RESULTS WITH**
4 **STAKEHOLDERS PRIOR TO PERFORMING SCENARIO MODELING?**

5 A: Yes. Tri-State committed to hold at least two meetings with interested
6 stakeholders in advance of beginning Phase I modeling to seek input on ELCCs.⁴
7 Ultimately, five discussions were convened on this topic. Tri-State first shared its
8 approach to the ELCC Study during a meeting with stakeholders on January 17,
9 2023. During that initial meeting, Tri-State indicated its intention to calculate ELCC
10 values based on a deterministic approximation method developed by the National
11 Renewable Energy Laboratory (“NREL”). On February 23, 2023, Tri-State again
12 met with stakeholders to share updates to the ELCC calculations. However, during
13 a meeting on March 14, 2023, stakeholders questioned whether a probabilistic
14 method for determining ELCCs could be used instead of the NREL method. On

⁴ 2020 ERP Settlement Agreement, Section 3.11.13.

1 April 24, 2023, Tri-State met with stakeholders again to discuss two possible paths
2 forward for the ELCC Study: (1) one that would require several months to hire a
3 third-party consultant to complete a probabilistic study for Phase I, and (2) one that
4 would maintain the NREL method for Phase I and update ELCCs using a
5 probabilistic study in advance of Phase II. Stakeholders indicated preference for
6 a probabilistic study to be performed for Phase I. Tri-State met with stakeholders
7 on this topic again on July 19, 2023 to present the results of the probabilistic study
8 completed by Astrape.

9 **Q: PLEASE DESCRIBE THE ELEMENT OF THE ASTRAPE STUDY RELATING TO**
10 **PRM.**

11 A: The study completed by Astrape also calculated a PRM for Phase I of the 2023
12 ERP. Astrape modeled the system using thousands of simulations varying
13 weather, hourly and peak loads, and unit outages, with the calculated PRM being
14 based on the weighted average results. The result being a PRM of 22 percent,
15 transitioning to 30.5 percent after retirement of Craig Station.⁵

16 Some of the factors noted by Astrape in their study that influenced the PRM
17 include:

- 18 • Impact of “shaft risk,” which is the risk associated with the potential loss of
19 units that are large relative to peak load. With Tri-State’s load being
20 reduced by approximately one-third due to Member exits and the Craig
21 Station retiring, more risk relative to load is placed on the remaining

⁵ Attachment G-1, pg. 67. LKT-29

1 dispatchable units.

2 • The PRM calculation also discounts the capacity of conventional resources
3 by their Equivalent Forced Outage Rate and several of Tri-State's thermal
4 resources have relatively high and increasing forced outage rates.

5 **c. IRA Scenario Reliability Evaluation**

6 **Q: PLEASE DESCRIBE THE PURPOSE OF THE IRA SCENARIO RELIABILITY**
7 **EVALUATION.**

8 A: Astrape was engaged by Tri-State to conduct an analysis of the IRA Scenario's
9 reliability in 2032.

10 **Q: WHAT DOES THE EVALUATION SHOW?**

11 A: The evaluation shows that the IRA Scenario is reliable with a very low LOLE of
12 0.036 days/year in 2032, providing additional assurance of reliability as a result of
13 this plan.

14 **d. DSM Potential Study**

15 **Q: PLEASE DESCRIBE THE DSM POTENTIAL STUDY.**

16 A: The DSM Potential Study identifies potential energy savings and associated costs
17 for attaining energy savings under varying DSM Potential Study scenarios. The
18 potential is derived from measure-level analysis, incentive and avoided cost
19 assumptions, and factors related to the Tri-State system and consumer behavior.
20 While Tri-State does not directly offer retail consumer services or programs, we
21 work closely with our Members to facilitate their DSM program offerings and ease
22 program administration burdens.

23 **Q: IS OUTPUT FROM THE DSM POTENTIAL STUDY USED TO MODEL THE**

1 **COLORADO ENERGY EFFICIENCY TARGETS THAT TRI-STATE HAS**
2 **COMMITTED TO STARTING IN 2023?**

3 A: No. Tri-State models the 2023, 2024, 2025, and 2030 EE Targets⁶ as a “must-
4 take” level of energy savings in the resource planning period (“RPP”) in all 2023
5 ERP Phase I scenarios, for the ECO and WCO planning regions. The EE Targets
6 are identified in ~~Attachment B of the ERP Report (LKT-1)~~ ^{LKT-7}. The 2025 EE Target
7 is held constant from 2025-2029 and the 2030 target is held constant through the
8 remainder of the planning period.

9 **Q: HOW ARE THE RESULTS OF THE DSM POTENTIAL STUDY USED IN TRI-**
10 **STATE’S 2023 ERP PHASE I MODELING?**

11 A: For any ERP scenarios that allows for either deeper levels of energy savings in
12 ECO and WCO, or DSM as a selectable option for the NM or Wyoming/West
13 Nebraska (“WYO/WNE”) regions, the DSM Potential Study determines the level of
14 energy savings assumed. Tranches of energy savings opportunity are selectable
15 only based on the DSM Potential Study scenario levels (e.g., Low, Moderate, etc.).
16 The costs to achieve the level of assumed energy savings also reflects input from
17 Tri-State DSM program staff.

18 **e. BE Potential Study**

19 **Q: PLEASE DESCRIBE TRI-STATE’S BE POTENTIAL STUDY.**

20 A: The BE Potential Study identifies potential load growth opportunities from
21 electrification and associated costs for attaining the additional load under varying

⁶ 2020 ERP Settlement Agreement, section 3.11.9.

1 BE Potential Study scenarios. The potential is derived from measure-level
2 analysis, incentive and avoided cost assumptions, and factors related to the Tri-
3 State system and consumer behavior. While Tri-State does not directly offer retail
4 consumer services or programs, we do work closely with our members to facilitate
5 their BE program offerings and ease program administration burdens.

6 **Q: HOW ARE THE RESULTS OF THE BE POTENTIAL STUDY USED IN TRI-
7 STATE'S PHASE I MODELING?**

8 A: The BE Potential Study determines the level of new load assumed based on
9 study's scenario levels (e.g., Low, Moderate, etc.). For all scenarios in the 2023
10 ERP Phase I, Tri-State's load forecast is adjusted to reflect inclusion of the
11 Achievement-Moderate level of BE. This approach is pursuant to the 2020 ERP
12 Phase I Unopposed Comprehensive Settlement Agreement in Proceeding No.
13 20A-0528E ("2020 ERP Settlement Agreement").⁷

14 **Q: DID TRI-STATE FULFILL ITS COMMITMENT TO HOLD STAKEHOLDER
15 MEETINGS ON BE PRIOR TO MODELING?**

16 A: Yes. Pursuant to 2020 ERP Phase I Settlement Agreement, Tri-State held two
17 stakeholder meetings on BE best practices in advance of the 2023 ERP modeling,
18 as identified in the ERP Report (**Attachment LKT-1**).

19 **IV. GENERIC RESOURCE MODELING**

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

21 A: In this section of my Direct Testimony, I discuss Tri-State's approach to generic

⁷ 2020 ERP Settlement Agreement, section 3.11.11.

1 resources modeled in the ERP.

2 **Q: PLEASE DESCRIBE TRI-STATE’S APPROACH TO GENERIC RESOURCES.**

3 A: New to the 2023 ERP Phase I, Tri-State included several new emerging
4 technologies as generic resource options available for scenario modeling. Tri-
5 State also held meetings with stakeholders, prior to modeling, to share data and
6 assumptions for both new and existing generic resource options.⁸ Tri-State also
7 refreshed data and assumptions for the generic resource types that had been
8 modeled in the 2020 ERP.

9 **Q: HOW ARE GENERIC RESOURCES MODELED IN THE ERP?**

10 A: In expansion plan modeling in EnCompass, a given scenario results in the
11 selection of a unique set of generic resource types, locations, and target
12 commercial operation dates (“CODs”). The modeling assesses a variety of factors
13 in determining the expansion plan needed to meet Tri-State system load and PRM
14 over the resource planning period. Such factors include, but are not limited to,
15 financial assumptions regarding resource costs, resource operational parameters,
16 and environmental characteristics of the available technologies. The expansion
17 plan output reflects the optimal solution for economically meeting the numerous
18 constraints input into the model, such as transmission and new build constraints
19 ~~(Attachment B-1, B-2 of the ERP Report (LKT-1)),~~ emissions reduction targets,
20 and others.⁹

⁸ Pursuant to 2020 ERP Settlement Agreement, Section 3.11.15., Tri-State held several meetings with stakeholders to discuss new generic resources (as identified in the ERP Report (**Attachment LKT-1**)) and shared generic resource assumptions with stakeholders in advance of modeling.

⁹ 2020 ERP Settlement Agreement 3.3.4. and 3.3.5.

1 **Q: WHAT NEW TECHNOLOGIES DID TRI-STATE INCLUDE IN ITS GENERIC**
2 **RESOURCE DATASET?**

3 A: New technologies modeled in the Phase I 2023 ERP are identified in **Attachment**
4 **LKT-16**
~~C-2 of the ERP Report (LKT-1)~~ and include:

- 5 • 10-hour Battery Storage
- 6 • Molten Salt Long-Term Storage;
- 7 • Iron Air Multi-Day Storage;
- 8 • Advanced and Enhanced Geothermal;
- 9 • Green and Blue Hydrogen;
- 10 • Natural Gas Combined Cycle with Carbon Capture and Sequestration
- 11 (“NGCCS”); and
- 12 • Small Modular Reactors (“SMRs”).

13 Key financial, operational, and environmental assumptions about each
14 technology type are included in **Attachment LKT-16**
~~C-2 of the ERP Report (LKT-1)~~. The
15 sources for this data include third-party experts, technology vendors, and trusted
16 industry research sources such as the National Laboratories. Not all technologies
17 are assumed to be deployment-ready during the first year of the RPP. Additionally,
18 several of the new technologies were not selected in any of the scenario expansion
19 plans.

20 **Q: HOW DID TRI-STATE CONSIDER THE IMPACT OF FEDERAL FUNDING**
21 **OPPORTUNITIES IN PRICING GENERIC RESOURCES?**

22 A: The financial assumptions for the generic resources reflect applicable available

1 federal tax incentives, including the Investment Tax Credit (“ITC”) or Production
2 Tax Credit (“PTC”). The following technology types are assumed to be eligible for
3 a 40 percent ITC:

- 4 • battery component of hybrid build-transfer;
- 5 • 4- and 10-hr batteries;
- 6 • pumped storage;
- 7 • advanced geothermal;
- 8 • enhanced geothermal baseload;
- 9 • enhanced geothermal with 12-hour storage;
- 10 • green hydrogen; and
- 11 • SMRs.

12 Molten salt and iron air technologies are assumed to be eligible for a 50
13 percent ITC, due to the expectation that they could qualify for the domestic content
14 bonus credit.

15 The following technology types are assumed to be eligible for an energy-
16 production based PTC:

- 17 • solar
- 18 • wind;
- 19 • solar and wind hybrids;
- 20 • blue hydrogen; and
- 21 • NGCCS.

22 For both existing and generic resources, that were assumed to be build-

1 transfer projects owned by Tri-State, it is assumed that Tri-State would be eligible
2 for direct pay of tax credits, as described in the Direct Testimony of Lisa Tiffin.

3 **V. MARKET DEPTH ASSUMPTIONS**

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

5 A: In this section of my Direct Testimony, I discuss how Tri-State’s planned market
6 participation is reflected in the modeling approach.

7 **Q: HOW DOES TRI-STATE’S MODELING ACCOUNT FOR TRI-STATE’S**
8 **CURRENT AND PLANNED MARKET PARTICIPATION?**

9 A: As identified in Proceeding No. 23M-0195E, Tri-State plans for its loads,
10 resources, and transmission system in the Western Area Power Administration
11 Colorado-Missouri Region (“WACM”) balancing authority to join the Southwest
12 Power Pool (“SPP”) Regional Transmission Organization (“RTO”) in the Western
13 Interconnection on April 1, 2026. In Tri-State’s 2023 ERP Phase I modeling, we
14 simulate the impact of this portion of our system entering the market by increasing
15 market sales and purchase depths starting in 2026. Additional detail on the
16 specific depths and assumptions can be found in **Attachment B** of the ERP Report
17 ~~(LKT-1)~~. LKT-7

18 **Q: IS THIS A REASONABLE MODELING APPROACH?**

19 A: Yes. Because Tri-State does not yet have the capacity to employ a nodal model,
20 adjusting market depth parameters is the best approach available. As Tri-State
21 continues to make progress toward SPP RTO market participation for its WACM
22 load and resources, we anticipate transitioning our EnCompass model to employ
23 a nodal approach for the 2027 ERP.

1 **VI. SENSITIVITY ANALYSES**

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

3 A: In this section of my Direct Testimony, I discuss the two sensitivity analyses that
4 Tri-State modeled for each scenario.

5 **Q: WHAT SENSITIVITIES DID TRI-STATE MODEL?**

6 A: Tri-State assessed each scenario's performance under two sensitivity analyses—
7 one that simulated extreme weather event ("EWE") conditions and one that
8 evaluated High Gas prices.

9 **Q: PLEASE DESCRIBE THE SENSITIVITY ANALYSES TRI-STATE COMPLETED**
10 **FOR EACH SCENARIO.**

11 A: For each scenario, Tri-State tested system performance under both EWE and High
12 Gas conditions, separately. For the EWE sensitivity, transmission, load,
13 renewable and thermal generation, and gas and power market prices were
14 stressed (as described in **Attachment B-5** of the ERP Report (~~LKT-1~~)) for a one-
15 week period in each winter and summer season during the Resource Acquisition
16 Period ("RAP") to evaluate each scenario's performance under those conditions.
17 Each scenario maintains its base expansion plan throughout the sensitivity
18 analyses, but each scenario is re-dispatched in EnCompass with the stressed
19 parameters to model the impact of an extreme weather or high gas event.

20 The approach to EWE sensitivity modeling in Phase I of the 2023 ERP is
21 different from the approach in Phase II of the 2020 ERP in that the EWE stress
22 assumptions are included in the modeling of each scenario's expansion plan. This
23 approach resolved the issue that occurred in the 2020 ERP Phase II of scenarios

1 not meeting the Level II reliability metrics under initial modeling runs due to lack of
2 expansion plan visibility into the EWE parameters. The base dispatch for each
3 scenario does not reflect the EWE stress, to enable assessment of the financial
4 results for each scenario under assumed normal system conditions.

5 For the High Gas sensitivity, stressed gas and power market prices¹⁰ were
6 applied in the modeling to evaluate each scenario's financial performance under
7 that condition (as described in **Attachment E** of the ERP Report (~~LKT-1~~),
8 providing another look at dispatch results.

9 **Q: DID TRI-STATE ENGAGE STAKEHOLDERS IN IDENTIFYING AND**
10 **DEVELOPING THE SENSITIVITIES MODELED?**

11 A: Yes. Tri-State held several meetings with interested stakeholders between
12 January 17 and July 19, 2023, prior to beginning modeling, to discuss potential
13 scenarios and sensitivities to be modeled and Tri-State's approach to EWE data
14 and related reliability metrics. During those meetings, Tri-State reviewed potential
15 scenarios and sensitivities and made adjustments based on stakeholder feedback.
16 Tri-State also shared its approach to the EWE stress, detail on historical EWE data
17 evaluated, planned EWE resource and transmission stresses and how each
18 differed from the 2020 ERP Phase II EWE modeling, and provided options for
19 potential approaches to the EWE load stress for stakeholder input. These
20 meetings are identified in ERP Report (LKT-1).

21 **Q: WHAT ARE THE KEY ASSUMPTIONS FOR THE EWE SENSITIVITY?**

¹⁰ Market prices are provided by a third-party vendor, Horizons Energy—a analytics, data, and consulting company.

1 A: The EWE sensitivity simulates a 168-hour period in the summer and in the winter
2 where extreme weather occurs, during a forecasted peak load period and resource
3 availability and system operations are constrained. The EWE stress assumptions
4 are described in detail within ~~Attachment B-5 of the ERP Report (LKT-1)~~ ^{LKT-12} and
5 reflect modifications from historical EWE conditions to address the Commission's
6 statement in Decision No. C23-0437 that "...an EWE that merely replicates past
7 heat waves or winter storms might be an insufficient test of the resource adequacy
8 of the portfolios under consideration in future ERPs."¹¹

9 **Q: PLEASE DESCRIBE THE DATA INPUTS FOR THE EWE SENSITIVITY.**

10 A: Tri-State primarily utilized historical data from EWE periods to develop EWE
11 sensitivity stresses. These data informed the length of the EWE, the initial
12 resource profiles, and expected transmission constraints. The following periods of
13 historical EWEs were evaluated:

- 14 • July 2018 Heat Wave: 7/7-7/11 (5-day event)
- 15 • July 2022 Heat Wave: 7/17-7/19 (3-day event)
- 16 • Feb 2021 Winter Storm Uri: 2/13-2/17 (5-day event)
- 17 • Dec 2022 Winter Storm Elliot: 12/21-12/26 (6-day event)

18 Tri-State also utilized renewable resource performance profiles from some
19 of these events, where available for existing resources on the Tri-State system.
20 EWE stress data is applied on a regional basis, reflective of Tri-State system
21 diversity. From these data, Tri-State made any necessary adjustments to reflect a

¹¹ Decision No. C23-0437, at ¶ 57.

LKT-12

1 reasonable time period for events (month of occurrence and length of days), to
2 sync profiles of resource stresses to load as both are impacted by weather, and to
3 ensure a robust but reasonable stress not solely based on past weather conditions.
4 The approach to these adjustments is described in **Attachment B-5** of the ERP
5 Report (~~LKT-1~~).

6 **Q: BEYOND THE CHANGE IN APPROACH TO MODELING, WHAT INPUT**
7 **ASSUMPTIONS WERE CHANGED FOR EWE SENSIVITIES SINCE THE 2020**
8 **ERP?**

9 **A:** Nearly all of the EWE modeling assumptions were modified for the 2023 ERP.
10 Data input assumption modifications for the EWE sensitivity include:

- 11 • **Length of EWE:** The timeframe for each EWE was shortened from two
12 weeks to one week (168 hrs).
- 13 • **Load Stress:** Instead of a 90 percent confidence interval load stress
14 applied equally to each hour, the load stress was based on a statistical
15 model difference between the actual storm event weather in terms of
16 precipitation for the month of the event and temperatures and 10-year
17 weatherized normal weather by region. The EWE week was grossed up by
18 the difference and the shape of the storm replaced the normalized shape
19 used for the storm week. EWE dates were selected such that the demand
20 peak in the months with EWE overlapped with the peak date of the storm.
21 Please see the Direct Testimony of Lisa A. Lynn for additional detail on the
22 load forecast assumptions and the extreme weather load forecasting
23 methodology.

- 1 • **Renewable Resource Stress:** Renewable resource stresses were based
2 on historical actual performance of renewable resources during prior EWEs
3 where available, as well as actual wind speed or solar irradiance during prior
4 EWEs. Renewables were stressed by an additional percentage, by region,
5 for 72 hours during the peak period of the EWE to reflect that future events
6 can be more severe than past events.
- 7 • **Thermal Resource Stress:** Outages and derates for existing thermal units
8 were applied based on actual performance during historical actual EWEs.
- 9 • **Transmission Constraint Stress:** The TOT 3 transmission path (a corridor
10 between southern Wyoming and northern Colorado) was reduced to 75
11 percent of Tri-State’s share of its transfer capacity for three days during the
12 winter EWE, and six hours (HE16-HE21) of every summer EWE period.
- 13 • **Limited Availability of Market Purchases:** Market purchases were
14 modeled in the dispatch as available during limited hours of each EWE.

LKT-12

15 Each of these stresses are described in **Attachment B-5** to the ERP Report
16 ~~(LKT-1)~~.

17 **Q: DID TRI-STATE EVALUATE THE POTENTIAL FOR APPLYING A**
18 **PROBABILISTIC MODELING APPROACH TO EWE?**

19 A: Given the short period of time between receipt of the 2020 ERP Phase II decision¹²
20 and the start of 2023 ERP Phase I modeling, Tri-State was not able to consider
21 the pursuit of probabilistic modeling for the EWE sensitivity. Tri-State will continue

¹² Decision No. C23-0437, at ¶56 (Proceeding No. 20A-0528E).

1 to evaluate opportunities to further enhance approaches to EWE sensitivity
2 modeling over time.

3 **Q: WHAT ARE THE KEY ASSUMPTIONS FOR THE HIGH GAS SENSITIVITY?**

4 A: The only modification for the High Gas Sensitivity is to stress the gas and electric
5 prices, to assess scenario performance. High Gas Sensitivity assumptions and
6 results are provided in **Attachment E** of the ERP Report (~~LKT-1~~).
LKT-25

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

8 A: Yes.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit DDD: Letter from Jerome H. Sturhahn, Senior Vice President of Tri-State, to
Shannon McMillian, Compliance and Enforcement Program Manager, CDPHE
(Jan. 26, 2026)



January 26, 2026

Submitted via email: cdphe_apcd_compliancetesting@state.co.us

Ms. Shannon McMillan
Compliance and Enforcement Program Manager
Colorado Department of Public Health and Environment
APCD-SS-B1
4300 Cherry Creek Drive South
Denver, Colorado 80246-1530

Re: Tri-State Generation and Transmission Association, Inc.
Craig Station Quarterly Mercury Reports: Fourth Quarter 2025

Dear Ms. McMillan:

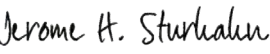
Tri-State Generation and Transmission Association, Inc. (Tri-State) submits the enclosed low emitter mercury reports for Craig Station for the fourth quarter of 2025, in accordance with Colorado Regulation 6, Part B.

During the reporting quarter, Craig Unit 3 operated very few hours in contrast to historical unit operations. As a result, the reported monitor downtime percentage for the sorbent trap system is high.

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in the attached report is true, accurate and complete.

If you have any questions regarding these reports, please contact Marc Mayzes or me at 303-452-6111.

Sincerely,

Signed by:

AFDDE2F9ABE741B...

Jerome H. Sturhahn
Senior Vice President,
General Counsel

JHS:MCM:BC

Enclosures

Files: G31-11.3(1)d-2e



January 26, 2026

Page 2

G32-11.3(1)d-2e

G33-11.3(1)d-2e

Low Emitter Quarterly Mercury Report Craig Unit 1 Fourth Quarter 2025		
Hg Emitted in Quarter	2.03	Pounds
Hg Emitted Annually (end of calendar year)	9.59	Pounds
Quarterly Unit Operating Time	1,736.20	Hours
Quarterly Total Monitoring System Downtime	77	Hours
Quarterly Monitoring System Downtime	4.43%	%
Hg Monitoring Method Used (CEMS, Sorbent Trap, Performance Testing)	CEMS	
If CEMS or Sorbent Trap: Manufacturer, Model and Serial Number	Tekran Series 3300 Serial Number 6082	
If Sorbent Trap Analyzed Off-Site: Lab Used	NA	
Date of Last Relative Accuracy Test Audit (RATA) and Entity Performing Test	RATA conducted June 16, 2025 by Montrose Environmental	
Date of Last Linearity Test	October 9, 2025	
Were there any QA/QC activities that differed from the monitoring plan used in the last quarter? If yes, please briefly describe. ¹	NO	
Have there been any changes to the Mercury Monitoring Plan and/or QA/QC Plan since the last quarterly report? If yes, please briefly describe.	NO	

¹ Low Emitters are not required to have mercury monitoring plans or QA/QC plans. This information need only be provided in the event a Low Emitter chooses to use Hg CEMs. In such event, monitoring plan requirements are contained in both Regulation 6, Part B and 40 C.F.R. Part 75.

Downtime Events

Plant: CRAIG

Report Period: 10/01/2025 00:00 Through 12/31/2025 23:59

Time Online Criteria: 1 minute(s)

Source: UNIT1

Parameter: HGT

Interval: 001H

Event ID	Date/Time	Reason Code - Description
1	10/07/25 05:00	73 - 1d-Not enough data for valid hour
2	10/08/25 08:00	43 - 1d-Routine or scheduled maintenance
3	10/08/25 09:00	43 - 1d-Routine or scheduled maintenance
4	10/08/25 10:00	43 - 1d-Routine or scheduled maintenance
5	10/08/25 11:00	43 - 1d-Routine or scheduled maintenance
6	10/08/25 12:00	43 - 1d-Routine or scheduled maintenance
7	10/14/25 05:00	73 - 1d-Not enough data for valid hour
8	10/16/25 09:00	73 - 1d-Not enough data for valid hour
9	10/21/25 05:00	73 - 1d-Not enough data for valid hour
10	10/28/25 05:00	73 - 1d-Not enough data for valid hour
11	11/04/25 04:00	69 - 1d-Previous integrity check expired
12	11/04/25 05:00	69 - 1d-Previous integrity check expired
13	11/04/25 06:00	69 - 1d-Previous integrity check expired
14	11/04/25 07:00	69 - 1d-Previous integrity check expired
15	11/04/25 08:00	69 - 1d-Previous integrity check expired
16	11/04/25 09:00	69 - 1d-Previous integrity check expired
17	11/04/25 10:00	69 - 1d-Previous integrity check expired
18	11/04/25 11:00	69 - 1d-Previous integrity check expired
19	11/04/25 12:00	69 - 1d-Previous integrity check expired
20	11/04/25 13:00	69 - 1d-Previous integrity check expired
21	11/04/25 14:00	69 - 1d-Previous integrity check expired
22	11/04/25 15:00	69 - 1d-Previous integrity check expired
23	11/04/25 16:00	69 - 1d-Previous integrity check expired
24	11/04/25 17:00	69 - 1d-Previous integrity check expired
25	11/04/25 18:00	69 - 1d-Previous integrity check expired
26	11/04/25 19:00	69 - 1d-Previous integrity check expired
27	11/04/25 20:00	69 - 1d-Previous integrity check expired
28	11/11/25 05:00	37 - 1c-Quality assurance check
29	11/18/25 05:00	37 - 1c-Quality assurance check
30	11/18/25 11:00	27 - 1b-Monitor component malfunction
31	11/18/25 12:00	27 - 1b-Monitor component malfunction
32	11/18/25 14:00	27 - 1b-Monitor component malfunction
33	11/18/25 15:00	27 - 1b-Monitor component malfunction
34	11/18/25 16:00	27 - 1b-Monitor component malfunction
35	11/18/25 17:00	27 - 1b-Monitor component malfunction
36	11/18/25 18:00	27 - 1b-Monitor component malfunction
37	11/18/25 19:00	27 - 1b-Monitor component malfunction
38	11/18/25 20:00	27 - 1b-Monitor component malfunction
39	11/18/25 21:00	27 - 1b-Monitor component malfunction
40	11/18/25 22:00	27 - 1b-Monitor component malfunction
41	11/18/25 23:00	27 - 1b-Monitor component malfunction
42	11/19/25 00:00	27 - 1b-Monitor component malfunction
43	11/19/25 01:00	27 - 1b-Monitor component malfunction

Downtime Events

Plant: CRAIG

Report Period: 10/01/2025 00:00 Through 12/31/2025 23:59

Time Online Criteria: 1 minute(s)

Source: UNIT1

Parameter: HGT

Interval: 001H

Event ID	Date/Time	Reason Code - Description
44	11/19/25 02:00	27 - 1b-Monitor component malfunction
45	11/19/25 03:00	27 - 1b-Monitor component malfunction
46	11/19/25 04:00	27 - 1b-Monitor component malfunction
47	11/19/25 05:00	27 - 1b-Monitor component malfunction
48	11/19/25 10:00	27 - 1b-Monitor component malfunction
49	11/19/25 11:00	27 - 1b-Monitor component malfunction
50	11/19/25 12:00	27 - 1b-Monitor component malfunction
51	11/25/25 05:00	37 - 1c-Quality assurance check
52	12/01/25 05:00	47 - 1b-Sampling system problem
53	12/01/25 06:00	47 - 1b-Sampling system problem
54	12/01/25 07:00	47 - 1b-Sampling system problem
55	12/01/25 08:00	47 - 1b-Sampling system problem
56	12/01/25 09:00	47 - 1b-Sampling system problem
57	12/01/25 10:00	47 - 1b-Sampling system problem
58	12/01/25 11:00	47 - 1b-Sampling system problem
59	12/01/25 12:00	47 - 1b-Sampling system problem
60	12/01/25 13:00	47 - 1b-Sampling system problem
61	12/02/25 05:00	37 - 1c-Quality assurance check
62	12/04/25 05:00	47 - 1b-Sampling system problem
63	12/04/25 06:00	47 - 1b-Sampling system problem
64	12/04/25 07:00	47 - 1b-Sampling system problem
65	12/10/25 10:00	27 - 1b-Monitor component malfunction
66	12/10/25 11:00	27 - 1b-Monitor component malfunction
67	12/10/25 12:00	27 - 1b-Monitor component malfunction
68	12/10/25 13:00	27 - 1b-Monitor component malfunction
69	12/10/25 14:00	27 - 1b-Monitor component malfunction
70	12/10/25 15:00	27 - 1b-Monitor component malfunction
71	12/10/25 16:00	27 - 1b-Monitor component malfunction
72	12/10/25 17:00	27 - 1b-Monitor component malfunction
73	12/10/25 18:00	27 - 1b-Monitor component malfunction
74	12/10/25 19:00	27 - 1b-Monitor component malfunction
75	12/10/25 20:00	27 - 1b-Monitor component malfunction
76	12/16/25 05:00	73 - 1d-Not enough data for valid hour
77	12/17/25 11:00	73 - 1d-Not enough data for valid hour

Number of Events: 77

Low Emitter Quarterly Mercury Report Craig Unit 2 Fourth Quarter 2025		
Hg Emitted in Quarter	3.04	Pounds
Hg Emitted Annually (end of calendar year)	10.78	Pounds
Quarterly Unit Operating Time	2,207.27	Hours
Quarterly Total Monitoring System Downtime	22	Hours
Quarterly Monitoring System Downtime	1.00 %	%
Hg Monitoring Method Used (CEMS, Sorbent Trap, Performance Testing)	CEMS	
If CEMS or Sorbent Trap: Manufacturer, Model and Serial Number	Tekran Series 3300 Serial Number 6083	
If Sorbent Trap Analyzed Off-Site: Lab Used	NA	
Date of Last Relative Accuracy Test Audit (RATA) and Entity Performing Test	RATA conducted June 17, 2024 by Montrose Environmental	
Date of Last Linearity Test	October 8, 2025	
Were there any QA/QC activities that differed from the monitoring plan used in the last quarter? If yes, please briefly describe. ¹	NO	
Have there been any changes to the Mercury Monitoring Plan and/or QA/QC Plan since the last quarterly report? If yes, please briefly describe.	NO	

Downtime Events

Plant: CRAIG

Report Period: 10/01/2025 00:00 Through 12/31/2025 23:59

Time Online Criteria: 1 minute(s)

Source: UNIT2

Parameter: HGT

Interval: 001H

Event ID	Date/Time	Reason Code - Description
1	10/07/25 04:00	26 - 1d - Recovery following calibration
2	10/07/25 08:00	43 - 1d-Routine or scheduled maintenance
3	10/07/25 09:00	43 - 1d-Routine or scheduled maintenance
4	10/07/25 10:00	26 - 1d - Recovery following calibration
5	10/07/25 12:00	43 - 1d-Routine or scheduled maintenance
6	10/07/25 13:00	43 - 1d-Routine or scheduled maintenance
7	10/14/25 04:00	26 - 1d - Recovery following calibration
8	10/21/25 04:00	26 - 1d - Recovery following calibration
9	10/21/25 05:00	26 - 1d - Recovery following calibration
10	10/21/25 06:00	26 - 1d - Recovery following calibration
11	10/28/25 03:00	69 - 1d-Previous integrity check expired
12	10/28/25 04:00	69 - 1d-Previous integrity check expired
13	10/28/25 05:00	69 - 1d-Previous integrity check expired
14	10/28/25 06:00	69 - 1d-Previous integrity check expired
15	11/04/25 05:00	26 - 1d - Recovery following calibration
16	11/11/25 05:00	26 - 1d - Recovery following calibration
17	11/18/25 05:00	26 - 1d - Recovery following calibration
18	11/25/25 05:00	26 - 1d - Recovery following calibration
19	12/02/25 05:00	26 - 1d - Recovery following calibration
20	12/16/25 05:00	26 - 1d - Recovery following calibration
21	12/23/25 05:00	26 - 1d - Recovery following calibration
22	12/30/25 05:00	26 - 1d - Recovery following calibration

Number of Events: 22

Low Emitter Quarterly Mercury Report Craig Unit 3 Fourth Quarter 2025		
Hg Emitted in Quarter	0.01	Pounds
Hg Emitted Annually (end of calendar year)	2.34	Pounds
Quarterly Unit Operating Time	51.33	Hours
Quarterly Total Monitoring System Downtime	22	Hours
Quarterly Monitoring System Downtime	42.86 %	%
Hg Monitoring Method Used (CEMS, Sorbent Trap, Performance Testing)	Sorbent Traps	
If CEMS or Sorbent Trap: Manufacturer, Model and Serial Number	Environmental Supply Model Hg-324K Serial Numbers 1036 & 1043	
If Sorbent Trap Analyzed Off-Site: Lab Used	Ohio Lumex	
Date of Last Relative Accuracy Test Audit (RATA) and Entity Performing Test	RATA's conducted June 20, 2025 on console #1036 and June 19, 2025 on console #1043 by Montrose Environmental	
Were there any QA/QC activities that differed from the monitoring plan used in the last quarter? If yes, please briefly describe. ¹	NO	
Have there been any changes to the Mercury Monitoring Plan and/or QA/QC Plan since the last quarterly report? If yes, please briefly describe.	NO	

Downtime Events

Plant: CRAIG

Report Period: 10/01/2025 00:00 Through 12/31/2025 23:59

Time Online Criteria: 1 minute(s)

Source: UNIT3
 Parameter: HG#/GWHR
 Interval: 001H

Event ID	Date/Time	Reason Code - Description
1	11/25/25 13:00	19 - 1d - Missing non mercury component for calculation
2	11/25/25 14:00	19 - 1d - Missing non mercury component for calculation
3	11/25/25 15:00	19 - 1d - Missing non mercury component for calculation
4	11/25/25 16:00	19 - 1d - Missing non mercury component for calculation
5	11/25/25 17:00	19 - 1d - Missing non mercury component for calculation
6	11/25/25 18:00	19 - 1d - Missing non mercury component for calculation
7	11/25/25 19:00	19 - 1d - Missing non mercury component for calculation
8	11/25/25 20:00	19 - 1d - Missing non mercury component for calculation
9	11/25/25 21:00	19 - 1d - Missing non mercury component for calculation
10	11/25/25 22:00	19 - 1d - Missing non mercury component for calculation
11	12/30/25 04:00	19 - 1d - Missing non mercury component for calculation
12	12/30/25 05:00	19 - 1d - Missing non mercury component for calculation
13	12/30/25 06:00	19 - 1d - Missing non mercury component for calculation
14	12/30/25 07:00	19 - 1d - Missing non mercury component for calculation
15	12/30/25 08:00	19 - 1d - Missing non mercury component for calculation
16	12/30/25 09:00	19 - 1d - Missing non mercury component for calculation
17	12/30/25 10:00	19 - 1d - Missing non mercury component for calculation
18	12/30/25 19:00	19 - 1d - Missing non mercury component for calculation
19	12/31/25 01:00	19 - 1d - Missing non mercury component for calculation
20	12/31/25 03:00	19 - 1d - Missing non mercury component for calculation
21	12/31/25 04:00	19 - 1d - Missing non mercury component for calculation
22	12/31/25 19:00	19 - 1d - Missing non mercury component for calculation

Number of Events: 22