UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 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

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[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&ltype=pin&rtype=s&pin=&rse=0&maptype=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

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[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

Chris Wright
Secretary of Energy

cc: **<u>FERC Commissioners</u>**

Chairman Laura V. Swett

Commissioner David Rosner

Commissioner Lindsay S. See

Commissioner Judy W. Chang

Commissioner David A. LaCerte

**<u>Colorado Public Utilities Commission</u>**

Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

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The State Of Colorado's Request for Rehearing,
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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 Background[1]

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-I[2], 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 1000[4] 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.

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[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 Agreement[13]

#### 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]

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[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 unconstrainted 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.

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[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 Tr-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 cited 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 Testimony[54] 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,

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[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)

ATTEST: A TRUE COPY

Rebecca E White

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

Aviv Segev

Administrative Law Judge

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

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Exhibit B: Declaration of Josh Korth Declaration (Jan. 26, 2025)

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**UNITED STATES OF AMERICA**

**BEFORE THE**

**UNITED STATES DEPARTMENT OF ENERGY**

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**ORDER NO. 202-25-14**

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**DECLARATION OF JOSHUA KORTH**

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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. 202-25-14 ("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.

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 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 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 Order unjustly and improperly interferes with this planning.

**Department of Energy Order**

9. I am familiar with the 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 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 Order. The Air Division has 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 has been further advised by the operator that repairs and maintenance would need to be made to Craig Unit 1 in order to bring the unit back online. As of the date of this Declaration, I understand that at least some of those repairs and maintenance have been completed.

12. Forcing Craig Unit 1 to be repaired and made available for operation beyond its December 31, 2025 retirement date may 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 Clean Air Act and meet statutory statewide GHG reduction targets.

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

13. 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.

14. 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 $SO_2$; 13,239 tpy of NOx; 60 tpy of volatile organic compounds ("VOC"); and 498 tpy of CO.[1]

15. 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 of cyanide and 7,204 pounds of manganese.[2]

16. The December 31, 2025 scheduled retirement of Craig Unit 1 would have resulted in significant emissions reductions, reducing emissions by the amounts and types of air pollutants described above as well as others identified in Craig Unit 1's 2025 updated Air Pollution Emission Notice.

17. Craig Unit 1's startup and continued operation may also result in excess emissions. In the past, the 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

[1] Request Exhibit LL (Division, *Technical Review Document for Operating Permit 96OPMF155* (Jan. 2005)).
[2] *See* Request Exhibit MM (Tri-State, General APEN- Form APCD-200 (Apr. 21, 2025)).

greater emissions beyond the additional emissions generated from Craig Unit 1 not retiring as planned.

18. 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.

19. Pollutants like PM, SOx, GHG, NOx, 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.

20. 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.

21. 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.[3] Exposure to these pollutants may also increase risk of heart attacks, lung disease, respiratory problems, headaches, dizziness, and premature death.[4]

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[3] *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.

[4] *See* CDPHE, *Regional Haze in Colorado* (2026).

## 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.

22. While the Order requires Craig Unit 1 to comply with applicable environmental requirements "to the maximum extent feasible while operating consistent with the emergency conditions[,]" this direction is vague and unclear. The Air Division cannot ascertain what the Department has determined are appropriate operating conditions to ensure conflicts are minimized. Further, Craig Unit 1's continued operation will make cost-effective compliance with many State and federal air quality regulations infeasible.

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

24. 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.

25. *First*, Colorado's Air Commission adopted Craig Unit 1's retirement date of December 31, 2025 into Regulation Number 23.[5] This provision of Regulation Number 23 is federally enforceable because it has been approved by EPA into Colorado's SIP.[6]

26. *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.[7] Under the visibility program requirements, 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. 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 NOx, SOx, and PM, as well as monitoring and reporting requirements for tracking visibility impairment and emissions reductions over time.[8] The Department did no analysis to assess the impact of its Order on Colorado's compliance with the Clean Air Act visibility program.

[5] 5 Colo. Code Reg. § 1001-27.
[6] Approval and Promulgation of Air Quality Implementation Plans; Colorado; Regional Haze State Implementation Plan, 83 Fed. Reg. 31332 (July 5, 2018); EPA, *EPA Approved Statues and Regulations in the Colorado SIP* (Jan. 6, 2026).
[7] CDPHE, *Regional Haze in Colorado* (2026).
[8] Request Exhibit NN (Division, *Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)).

27. *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.[9] 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 incorporated into the operating permit. Both the SIP and the Title V permit have been reviewed and approved by the EPA.

28. *Fourth*, the 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 NOx. 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 Clean Air Act's NAAQS attainment program. And the lack of detail and clarity in the 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.

[9] Request Exhibit KK (Division, *Operating Permit No. 96OPMF155* (July 1, 2021)).

29. *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.[10] 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 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.

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

30. 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.

[10] § 25-7-102(2)(g), Colo. Rev. Stat.

31. 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 consistently with the Title V permit.

32. 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.

33. 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 is required to 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 Order, and an understanding of the actions that the operator will be required to undertake to comply with the 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 Order. The Department did not consult with the Air Division as to the quantification of these impacts or methods to minimize or mitigate them.

34. As an electric generating unit, Craig Unit 1 was required to conduct a Mercury and Air Toxics Standards ("MATS") federally required tune-up. Under 40 C.F.R. Part 63, Subpart UUUUU, the tune-up is required at least once every 36 calendar months and the facility is required to inspect, clean and repair components of the burner as necessary every required inspection period. If the inspection discovers worn or damaged burner components affecting the optimization of NOx and CO, the components must be replaced within three calendar months.[11] Because Tri-State Generation and Transmission Association, Inc.'s ("Tri-State"), planned for Craig Unit 1 to retire on or before December 31, 2025, Tri-State did not conduct a complete MATS tune-up in 2025. However, due to the Order, Tri-State recently conducted a complete MATS tune-up that involved the required inspection and necessary maintenance. Had Craig Unit 1 retired on or before its planned retirement date, Tri-State would not have completed this additional inspection and maintenance and incurred these additional costs. 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 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.

[11] 40 C.F.R. § 63.10021.

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

Executed this 26 day of January, 2026.

Joshua Korth Digitally signed by Joshua Korth
Date: 2026.01.26 17:29:38 -07'00'

Joshua Korth

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

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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.

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**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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# 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 $CO_2$, $SO_x$, $NO_x$, 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 Neat 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 $CO_2$, SOx, NOx, 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

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK[58]

MEGAN M. GILMAN

TOM PLANT

Commissioners

COMMISSIONER ERIC BLANK
DISSENTS, IN PART

[58]Eric Blank dissents in part.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit C: Declaration of Erin O'Neil (Jan. 26, 2025)

**UNITED STATES OF AMERICA**

**BEFORE THE**

**UNITED STATES DEPARTMENT OF ENERGY**

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**ORDER NO. 202-25-14**

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**DECLARATION OF ERIN O'NEILL**

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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. 202-25-14 ("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 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 Department's December 30, 2025 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 Unit 1 is 427 MW, for Unit 2 is 410 MW, and for 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 Plan, which included the announced retirements of Craig Unit 2 by September 30,

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[1] Request 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*.

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] The utility must conduct a periodic examination of its energy sales and demand forecasts as compared to its existing resources to ensure that

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[5] *See id*. at 23; Request 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] Request 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, C.R.S.; 4 Colo. Code Regs. § 723-3-3603(a) (2025).

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, 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. Colorado's resource planning process also 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.[11] The Colorado public utility statutes and the CoPUC's procedural rules also allow for the modification of prior CoPUC decisions, and waiver 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.

**A. Tri-State's Colorado Resource Planning Requirements**

16. For Tri-State specifically, 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]

17. 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]

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[10] 4 Colo. Code Regs. § § 723-3-3603(a), -3605(a)(II) (2025).
[11] 4 Colo. Code Regs. § 723-3-3102 (2025).
[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.
[16] 4 Colo. Code Regs. § 723-3-3605(a)(I), -(II) (2025).
[17] 4 Colo. Code Regs. §§ 723-3-3102, -3605(a)(II) (2025).

18. 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.

19. 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 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]

20. 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]

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

22. 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

[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.*
[22] 4 Colo. Code Regs. § 723-3-3605(e) (2025).
[23] *Id.*

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]

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

24. 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

[24] 4 Colo. Code Regs. § 723-3-3605(a), -(e)(III) (2025).
[25] 4 Colo. Code Regs. § 723-3-3605(g)(III)(B) (2025).

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]

25. 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]

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

**B. Public Service's Resource Planning Requirements**

27. Generally, the Colorado ERP requirements for Public Service are similar to those required for Tri-State,[30] but are even more thorough as Public Service serves

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[26] 4 Colo. Code Regs. § 723-3-3605(h) (2025).
[27] *Id.*
[28] *Id.*; § 40-2-134, Colo. Rev. Stat.
[29] 4 Colo. Code Regs. § 723-3-3618 (2025).
[30] *See* 4 Colo. Code Regs. §§ 723-3-3604 (Contents of the Resource Plan), -3606 (Electric Energy and Demand Forecasts), -3607 (Evaluation of Existing Resources), -3608 (Transmission Resources), -3609 (Planning Reserve Margins and Contingency Plans), -3610 (Assessment of Need for Additional

retail customers and is rate-regulated by the CoPUC. Public Service has been required to engage with the CoPUC on resource planning for decades.

28. As relevant to the Order's assertions regarding reliability, investor owned utilities such as Public Service must file an ERP application every four years and may file interim plans or CPCNs.[31] Each ERP application must include an assessment of the need for additional resources based on detailed demand and energy forecasts for each year within the planning period, including a range of forecast scenarios of coincident summer and winter peak demand and energy sales.[32] Each ERP application must justify planning reserve margins for base case, high, and low load forecast scenarios, and include evaluation of 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 regulatory requirements, and other risks.[33] Public Service must also describe and justify the means by which it assesses the desired level of reliability on its system.[34]

29. Just as with Tri-State's ERP proceedings, the CoPUC conducts an adjudicative process on Public Service's ERP applications. After discovery, rounds of written testimony, an evidentiary hearing with cross-examination by parties and the CoPUC, and any necessary briefing, a Phase I decision is issued that includes a determination on the need for additional resources and specifies the portfolios of

Resources), -3611 (Utility Plan for Meeting the Resource Need), -3613 (Bid Evaluation and Selection), -3616 (Requests for Proposals).

[31] 4 Colo. Code Regs. §§ 723-3-3603, -3102 (2025).

[32] 4 Colo. Code Regs. § 723-3-3606 (2025).

[33] 4 Colo. Code Regs. § 723-3-3609 (2025).

[34] *Id.*

resource combinations Public Service must model in Phase II after completion of its competitive, all-source acquisition process.

30. Within 120 days of Public Service's receipt of resource bids, Public Service must file a 120-Day Report that presents the resource portfolios required by the Phase I decision, cost and other information associated with each portfolio, and must identify its preferred cost-effective resource plan (*i.e.*, its preferred resource portfolio).[35] Parties may comment on the 120-Day Report, Public Service provides a response to stakeholder comments and after any additional necessary process, and then the CoPUC issues its Phase II decision establishing the final cost-effective resource plan. Public Service must also file annual progress reports with the CoPUC on its efforts under the approved plan and on emerging resource needs.[36]

31. Additionally, Public Service was statutorily required to file a Clean Energy Plan ("CEP") demonstrating compliance with State clean energy goals with its first ERP following January 1, 2020.[37] In evaluating the CEP, the CoPUC must consider, among other factors, the resource plan's impact on the reliability and resiliency of the electric system. The CoPUC is expressly prohibited from approving any clean energy plan that does not protect system reliability.[38]

## II. <u>Relevant CoPUC Resource Planning Proceedings</u>

32. 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 filed by Tri-State and Public Service. None of these proceedings

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[35] 4 Colo. Code Regs. § 723-3-3613(d) (2025).
[36] 4 Colo. Code Regs. § 723-3-3618 (2025).
[37] § 40-2-125.5(4)(a), Colo. Rev. Stat.
[38] § 40-2-125.5(4)(d), Colo. Rev. Stat.

resulted in a CoPUC determination that the retirement of Craig Unit 1 would result in reliability issues.[39]

### A. Tri-State's Colorado Resource Planning Proceedings

33. 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.[40] 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.

34. 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 would not need additional generation resources until 2023.[41] 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.[42]

35. Tri-State's 2015 IRP/ERP also catalogued its various methods for responding to unexpected capacity shortages, including employing small diesel

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[39] *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; Request Exhibit AA; Request 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.
[40] 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.
[41] *See id.* at 107, 132.
[42] *See id.* at 107.

generation and relying on its membership in utility reserve sharing groups or reciprocal outage assistance arrangements with other utilities.[43] 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.[44] 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.[45]

36. Tri-State first incorporated the retirement of Craig Unit 1 by December 31, 2025 in the scenario modeling for its 2017 Annual Progress Report.[46] 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 generating capacity would not be needed until 2025.[47] Subsequent annual progress reports moved this date to 2026 and then 2027.[48]

37. 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

[43] *See id.* at 108.
[44] *See id.*
[45] *See id.* at 107-108.
[46] CoPUC, ERP Annual Progress Report, Revised, filed on June 2, 2017, in Proceeding No. 15M-0852E.
[47] *See id.* at 16.
[48] 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.

potential benefits of lower cost electricity."[49] 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."[50]

38. 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, 2029.[51] 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.[52]

39. 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.[53] 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.[54] The study used the target "LOLP of less than [one] day in 10 years[,] which corresponds to

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[49] 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.

[50] 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.

[51] Request Exhibit F, at 31.

[52] CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, at 37:15-19.

[53] 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.

[54] *See id.* at 41:10-42:7; Request Exhibit F, at 2348-2356.

a LOLP of less than 0.0274 percent on an annual hour basis."[55] The study analyzed "two forecast years, 2025 and 2030, under four capacity expansion [("CE")] plans" using varying load forecasts and capacity addition assumptions.[56] 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.[57] The study found that additional energy storage capability would be able to compensate for these exceedances so that all scenarios met the LOLP target.[58] 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 preferred plan.[59] 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."[60]

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[55] *See id.* at 2355.
[56] *See id.* at 2351.
[57] *See id.* at 2351.
[58] *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).
[59] *See id.* at 30.
[60] *See id.* at 135.

40. 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.[61]

41. 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.[62] "[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.[63] Tri-State explained the Revised Preferred Plan was "the responsible and economic resource plan because it reflects the known financial, operational, and contractual conditions of our system, while maintaining a focus on reliability and affordability for our Members."[64]

42. 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.[65] The CoPUC also directed that after Tri-State receives resource bids, it

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[61] *See id.* at 30.
[62] 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.
[63] 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.
[64] *See id.*at 13:1-9.
[65] CoPUC, Decision No. R22-0191, issued on March 28, 2022, in Proceeding No. 20A-0528E.

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.[66]

43. 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.[67]

44. 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."[68] It 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.[69] 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."[70] In its Phase II decision, the CoPUC approved Tri-State's selection of the Revised Preferred Plan

[66] CoPUC, Decision No. R22-0191, issued on March 28, 2022, in Proceeding No. 20A-0528E, ¶¶ 49-50.
[67] CoPUC, 150-Day Report, Public, filed on February 13, 2023, in Proceeding No. 20A-0528E, at 17.
[68] *See id.* at 5.
[69] *See id.* at 28.
[70] *See id.*

portfolio as the cost-effective resource plan.[71] 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."[72]

45. 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."[73] 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.[74] Tri-State explained it "selected an acquisition period of six years through 2031 to ensure that, as fossil resource retirements in Colorado occur through the end of the decade, sufficient resources would be in place to continue to meet resource adequacy and reliability requirements."[75]

46. 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.[76] 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

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[71] CoPUC, Decision No. C23-0437, issued on June 30, 2023, in Proceeding No. 20A-0528E, 47.
[72] CoPUC, Notice of Failed Bids, Public, filed on July 24, 2023, in Proceeding No. 20A-0528E, 12.
[73] Request Exhibit W (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E), at 11:22-12:4.
[74] Request Exhibit X (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 (Tri-State, *2023 ERP Phase I*, Rev. 2 (Apr. 22, 2024))), at 19, 21, 32, 44, 55, 66.
[75] *See id.* at 6.
[76] Request 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.

"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."[77] 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.[78] 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 of load every 10 years.[79] 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."[80]

[77] Request Exhibit X, *See id.* at 14.
[78] Request 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.
[79] *See id.* at 8.
[80] 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), at 15:2-4.

47. 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.[81] "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.[82] Additional "Level 2" reliability checks were performed on each scenario's extreme weather event sensitivity result.[83] Tri-State explained that each scenario was able to meet the Level 1 and Level 2 reliability metrics during the resource acquisition period.[84]

48. 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.[85] 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.[86]

49. In its 2023 ERP Phase II Implementation Report, Tri-State reported on the results of its competitive resource solicitation and presented six resource portfolios.[87] The analysis of each portfolio includes in its assumptions the retirement

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[81] Request Exhibit X, at 15.
[82] *See id.* at 17.
[83] *See id.* at 18.
[84] *See id.* at 90.
[85] Request Exhibit AA, ¶¶ 50, 60.
[86] *See id.* ¶¶ 29, 50.
[87] Request Exhibit J (CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E).

of Craig Unit 1 by December 31, 2025, Craig Unit 2 by September 30, 2028, and Craig Unit 3 by January 1, 2028.[88] Tri-State also created three back-up bid pools.[89]

50. 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."[90] 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 retire two coal plants within the resource acquisition period.[91] 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.[92] The 307 MW gas facility will interconnect at the Craig transmission substation and has a commercial operation date of 2029.

51. 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.[93] 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

[88] *See id.* at 21, 32, 43, 54, 64, and 75.
[89] *See id.* at 7.
[90] *See id.* at 6.
[91] *See id.*
[92] *See id.* at 54.
[93] *See id.* at 95.

that period.[94] 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.[95]

52. In its advocacy, Tri-State highlighted the reliability benefits of the portfolio's inclusion of a dispatchable gas plant compared to additional reliance on batteries, beyond the 650 MW of battery storage included in the preferred portfolio. Tri-State explained that "although battery integration is important for a balanced energy strategy, the immediate needs of the Western Colorado system, particularly in the transition away from coal, require the inclusion of reliable dispatchable resources like gas plants to ensure overall system reliability."[96]

53. In its Phase II decision, the CoPUC approved Tri-State's selection of the FLEXSR portfolio as the cost-effective resource plan.[97] 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 same time, Tri-State convincingly concludes that every portfolio meets all reliability metrics and is reliable."[98]

54. 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

[94] *See id.* at 62.
[95] *See id.* at 7.
[96] CoPUC, Tri-State's Response Comments to its 2023 ERP Phase II Implementation Report, Public, filed on June 10, 2025, in Proceeding No. 23A-0585E, at 13.
[97] Request Exhibit E, 90.
[98] *See id.* 116.

contracting efforts for other preferred portfolio resources, including evaluation of back-up bids as needed."[99] 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.[100]

### B. Public Service's Resource Planning Proceedings

55. Additionally, the CoPUC has decided multiple Public Service resource planning proceedings that include the retirement of Craig Unit 1 by December 31, 2025, and account for Public Service's 42 MW share of the unit being unavailable by that date as an assumption in the modeling of resource needs and the approval of cost-effective resource plans.[101]

56. Public Service's 2021 ERP/CEP proceeding approved a cost-effective resource plan for the resource acquisition years 2022-2028.[102] The CoPUC Decision found the approved portfolio "protects reliability of the electrical system…."[103] Public Service is also engaging in a near term procurement process in its 2021 ERP/ECP proceeding, requesting to acquire additional resources with in-service dates prior to 2031.[104]

57. The CoPUC is currently considering an interim ERP, also known as the Just Transition Plan, filed by Public Service with staged resource solicitations for resource acquisitions in years 2027-2031 and years 2029-2033. The CoPUC issued a

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[99] Request Exhibit Z (CoPUC, Tri-State, *2025 Annual Progress Report*, filed on December 1, 2025, in Proceeding No. 23A-0585E), at 10-11.
[100] *See id.* at 8.
[101] 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.
[102] CoPUC, Decision No. C22-0459, issued on August 3, 2022, in Proceeding No. 21A-0141E, 4.
[103] CoPUC, Decision No. C24-0052, issued on January 23, 2024, in Proceeding No. 21A-0141E, 4.
[104] CoPUC, Public Service, Motion to Acquire Near-Term Procurement Resources, Public, filed on December 5, 2025, in Proceeding No. 21A-0141E.

Phase I 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 serve existing and future firm, projected energy demand.[105] The CoPUC also approved an innovative "Incremental Need Pool" of back-up and replacement projects.[106] These cost-effective projects receive option payments to remain available for development if fully approved projects fail or if load growth is higher than anticipated. The approved process provides Public Service multiple opportunities to acquire new resources in each of the next four years with two full, all-source solicitations and the subsequent establishment of an incremental need pool to quickly respond to additional load growth.

58. Additionally, on November 10, 2025, CoPUC Staff, the Colorado Energy Office ("CEO"), the Colorado Office of the Utility Consumer Advocate ("UCA") and Public Service jointly filed a petition requesting a variance from the CoPUC's decision approving Public Service's 2016 ERP to extend the planned retirement date of Comanche Unit 2 ("Pueblo Unit 2") from December 31, 2025 to December 31, 2026.[107] The petition stated that the filing parties "believe that the continued operation of Comanche Unit 2 in 2026 is the most cost-effective approach to providing needed electricity for the system...."[108] The CoPUC granted the requested extension of

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[105] CoPUC, Decision No. C25-0747, issued on November 6, 2025, in Proceeding No. 24A-0442E, 2.
[106] *See id.* 101.
[107] Request Exhibit Y (CoPUC, *Verified Petition of Trial Staff of the Commission, CEO, UCA, and Public Service for a Variance from Decision No. C18-0761 and Any Other Requirements, Request for Shortened Notice and Intervention Period, and Request for Approval of Associated Procedures* ("Comanche Unit 2 Variance Petition"), filed on November 10, 2025, in Proceeding No. 25V-0480E).
[108] *See id.* at 2.

Pueblo Unit 2's retirement date because a separate coal-fired unit was damaged and subject to a prolonged, unplanned outage predicted to last until at least June 2026.[109]

59. Through iterative, robust resource planning proceedings for Public Service, the CoPUC engages with Public Service on how it ensures resource adequacy for its customers. In addition to ERP proceedings on the regular cadence, Public Service and the CoPUC engage in flexible and responsive processes to address resource needs.

## Conclusion

60. 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.

61. 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

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[109] Request Exhibit BB (CoPUC, Decision No. C25-0892, issued on December 10, 2020, in Proceeding No. 25V-0480E), ¶¶ 1, 65.

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 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.

62. By delaying the retirement of an aging coal-fired unit that was not even operable at the time the Order was issued, 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 Digitally signed by Erin O'Neill
Date: 2026.01.26 18:23:08 -07'00'

Erin O’Neill

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 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)

# 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).

## Contents

## 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 Systems[1] 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

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[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 exogeneous 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 Requirements[2] 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 Peak*[5]

| 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 |

[redacted]

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.

[redacted]

[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.

[redacted]

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

[redacted]

## 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)(I)(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*

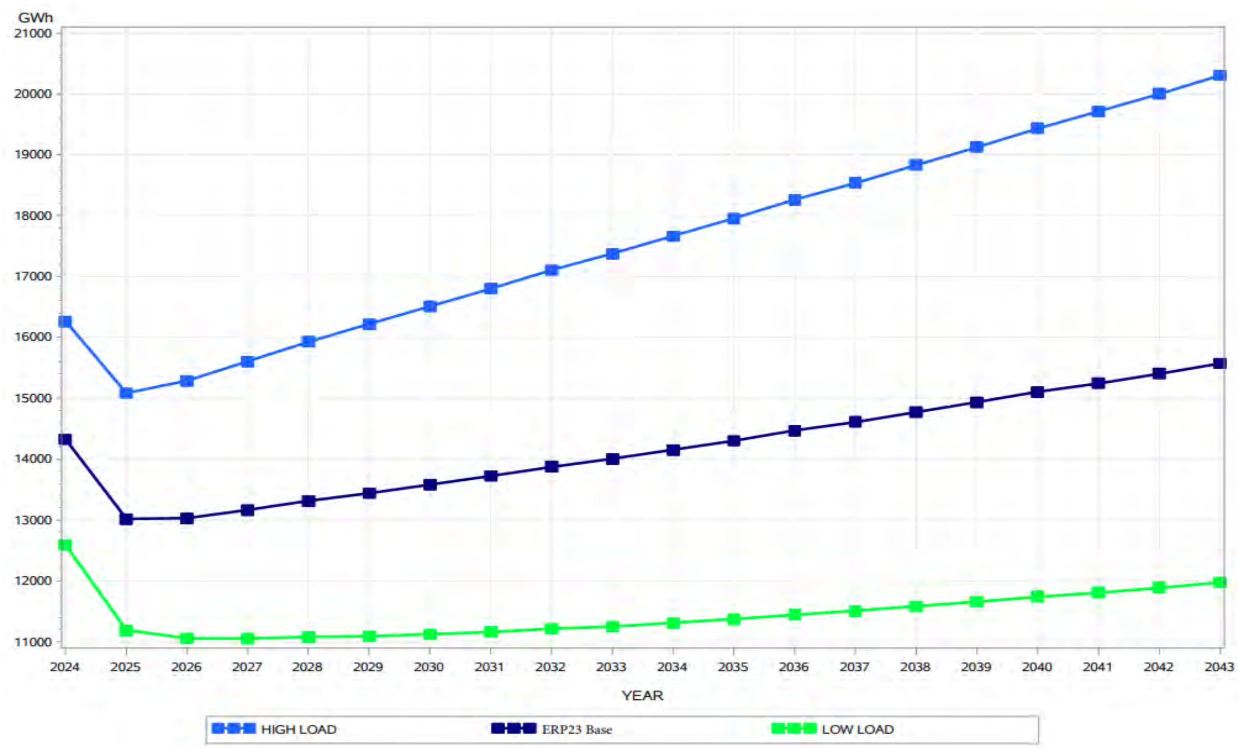


*Figure 2: Tri-State System Annual Coincident Summer Peak*

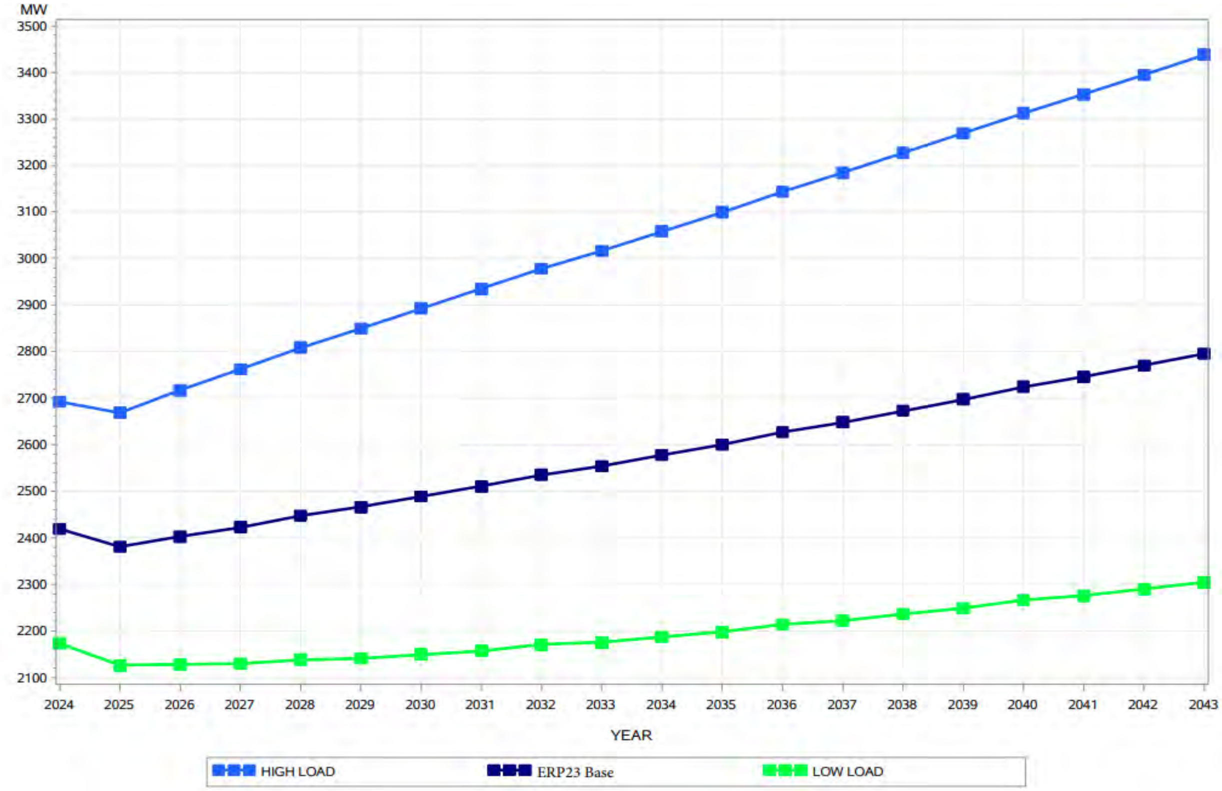
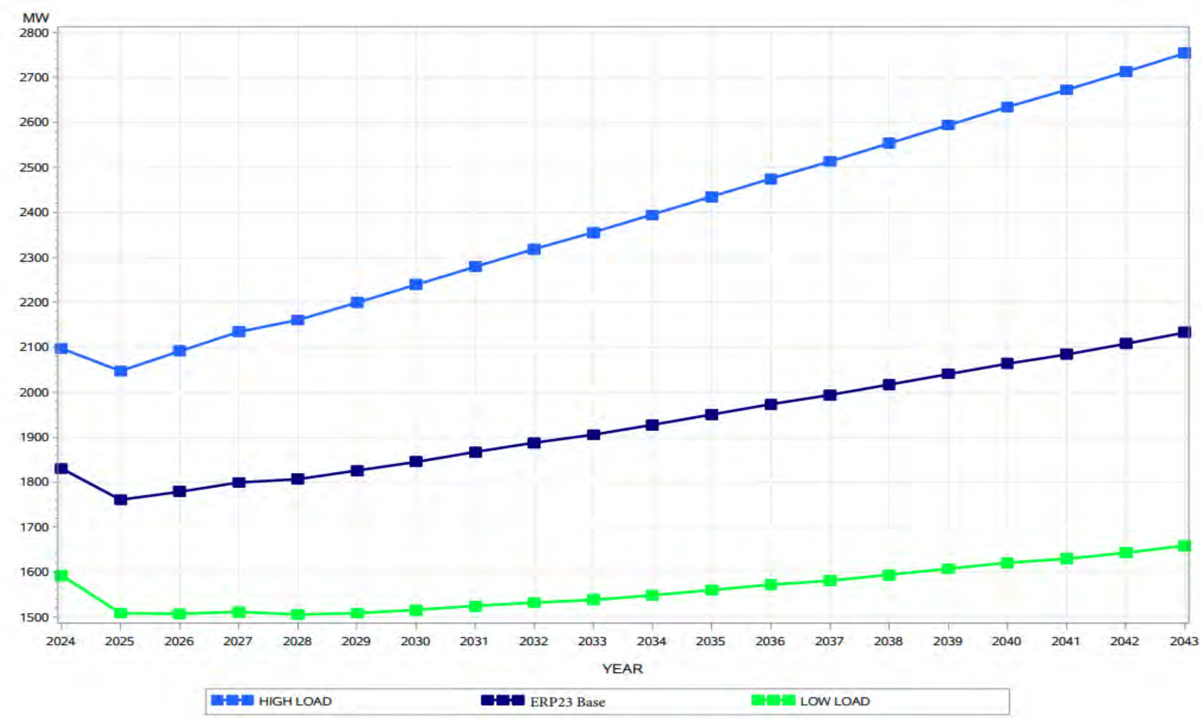



*Figure 3: Tri-State System Annual Coincident Winter Peak*



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 Forecast[8]

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 2040[9] 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*

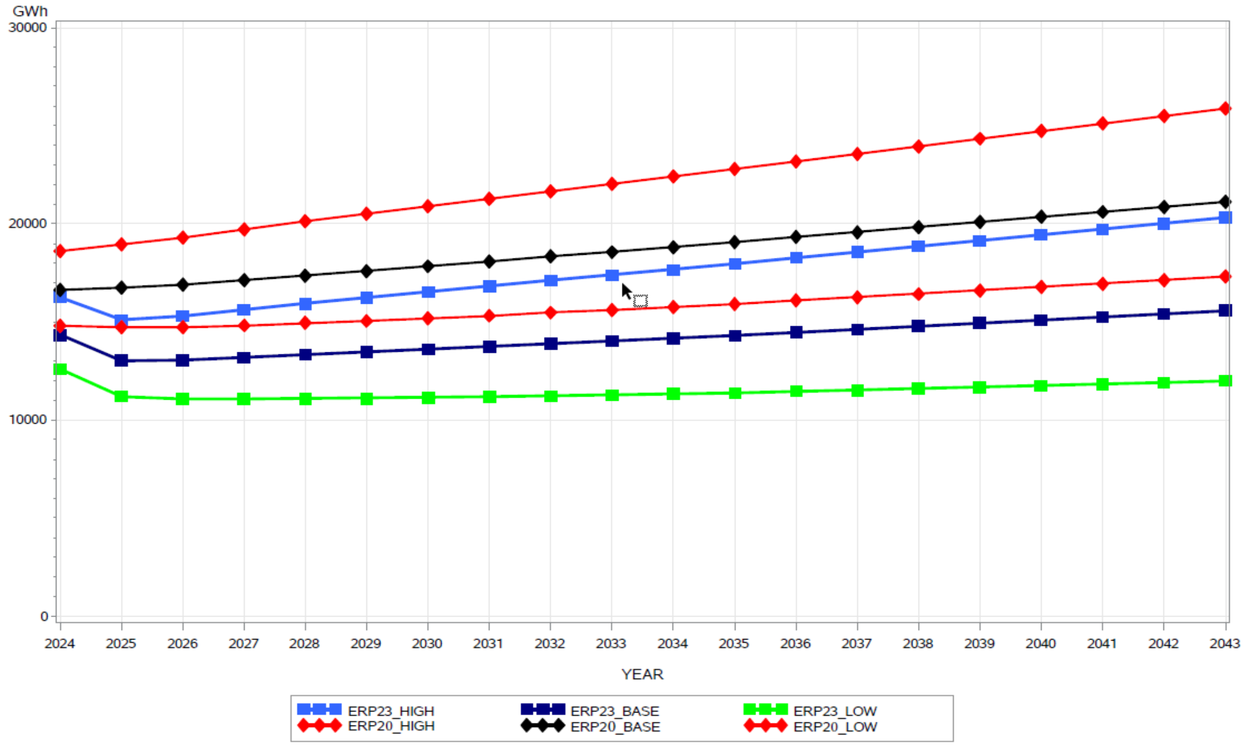



*Figure 5: Tri-State System Annual Summer Coincident Peak*

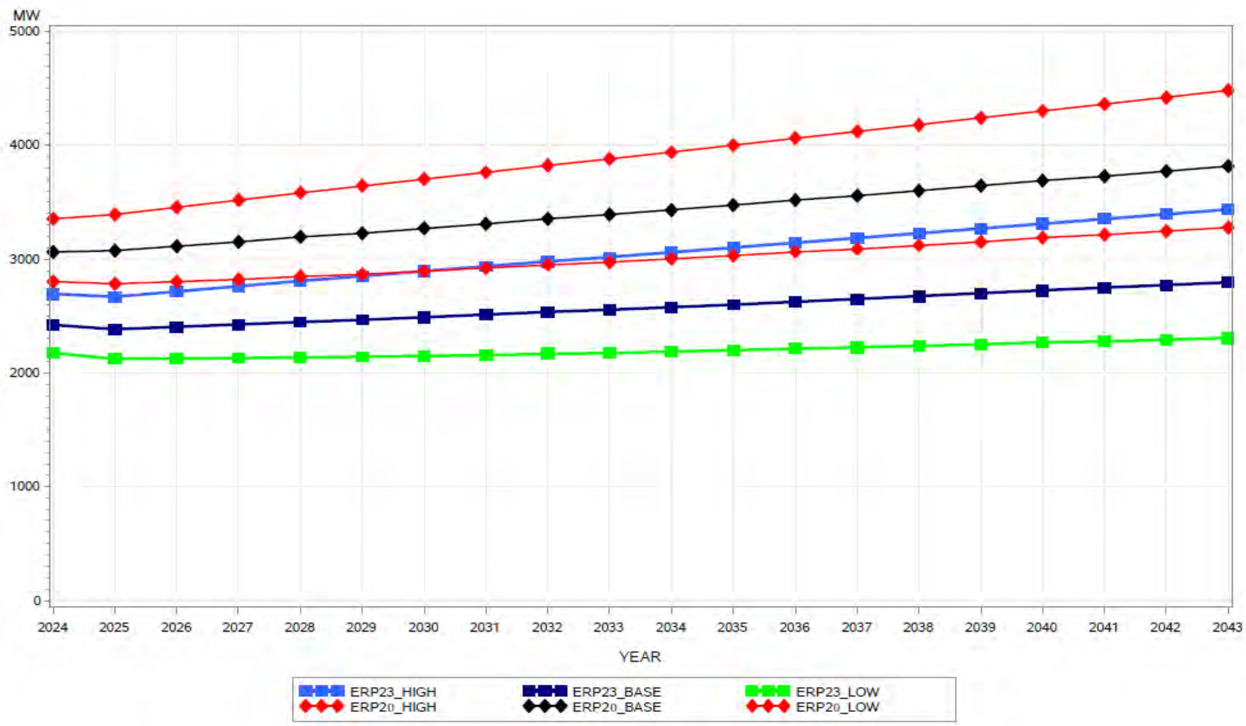
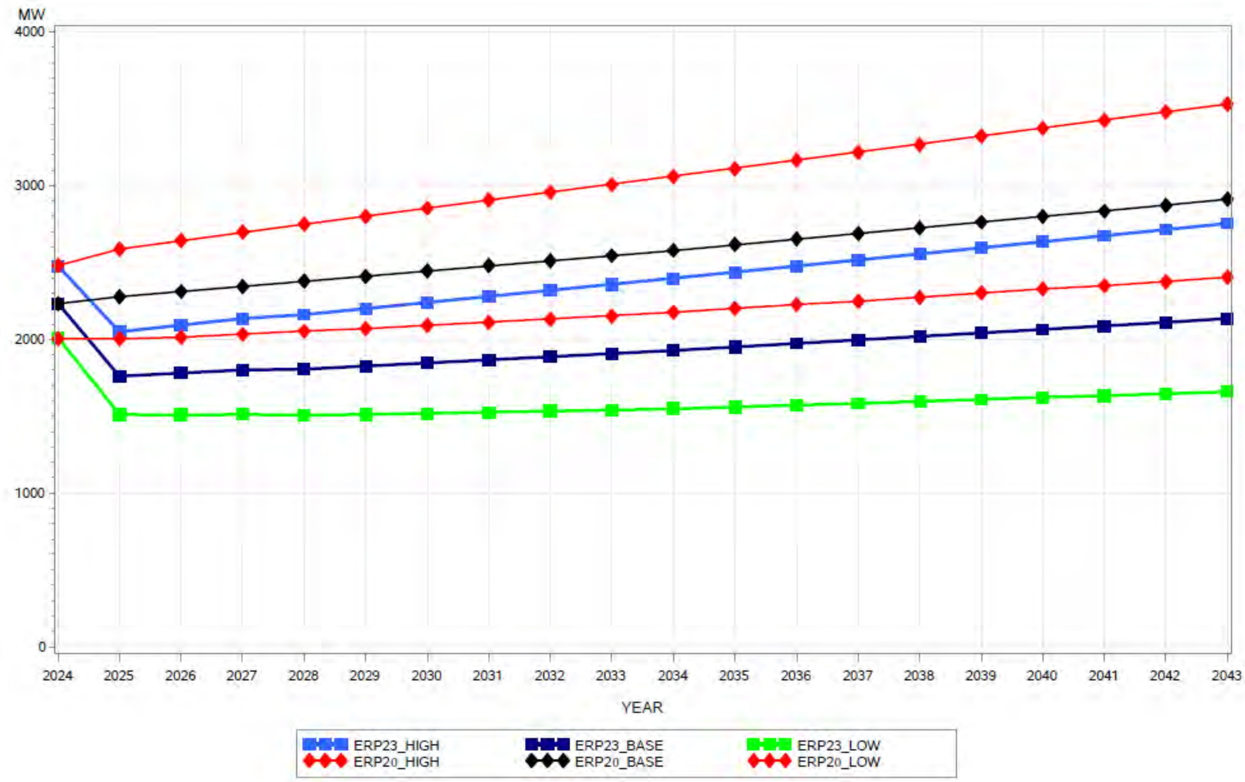


*Figure 6: Tri-State System Annual Winter Coincident Peak*




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.

[redacted]

## 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)*

| | | BASE FORECAST | | HIGH LOAD | | LOW LOAD | |
|---|---|---|---|---|---|---|---|
| YEAR | 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)*

| | | BASE FORECAST | | HIGH LOAD | | LOW LOAD | |
|---|---|---|---|---|---|---|---|
| YEAR | 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)*

| | | BASE FORECAST | | HIGH LOAD | | LOW LOAD | |
|---|---|---|---|---|---|---|---|
| YEAR | ACTUALS | 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

### Losses[10]

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 area[11], 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 Utilities[12]

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 Use[13]

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)(I)(B).
[13] Rule 3605(b)(I)(C).

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit D: Declaration of Joseph Pereira (Jan. 23, 2025)

**UNITED STATES OF AMERICA**

**BEFORE THE**

**UNITED STATES DEPARTMENT OF ENERGY**

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**ORDER NO. 202-25-14**

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**DECLARATION OF JOSEPH PEREIRA**

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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 Deputy 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") December 30, 2025 Order No. 202-25-14 ("Order") regarding a coal-fired generating unit ("Craig Unit 1") at the Craig Station facility in Craig, Colorado.

**<u>Personal Background and Qualifications</u>**

3. I have served as the Deputy Director of the UCA since 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 current role, 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. In my current role as Deputy Director of the UCA, I provide policy, regulatory, and advisory support to the Director of the UCA, support legislative efforts, offer expert testimony on behalf of the office, and oversee office administration.

7. The UCA is statutorily mandated 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 rates paid by consumers.[1]

8. 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 proceedings upon various classes of consumers.[2]

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[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.

9. 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 Order

10. I am familiar with and have fully reviewed the Department's Order regarding Craig Unit 1.

11. The Order's direction that the co-owners of Craig Unit 1: Tri-State, PacifiCorp, Platte River Power Authority, Salt River Project, and Public Service Company of Colorado ("Public Service") (together, "Craig Unit 1 Owners"), shall take all measures necessary to ensure it is available to operate for the duration of the Order runs counter to the public interest in Colorado. The Order is likely to increase costs for Colorado's rural electric cooperative customers, and it injects 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

12. Craig Unit 1's retirement, justified primarily by economics, has been anticipated by the 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]

13. The 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 Order, consumers who have been paying for Craig Unit 1's replacement generation may also be forced to pay for expensive, excess generation that was not requested by the Craig Unit 1 Owners and is not necessary.

14. 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 cost approximately $20 million in fuel, operations, and maintenance costs to continue operating Craig Unit 1 for the 90-day effective period of the 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 maintenance Tri-State may have chosen

[4] Tri-State, *Craig Station owners, regulators and environmental groups reach agreement on proposed revisions to Colorado regional haze plan* (Sept. 1, 2016).
[5] 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).

not to perform over the past several years when it 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.

15. Separate from the significant operations and fuel costs required to keep Craig Unit 1 available to operate, as of the time of the Order, Craig Unit 1 also needs repairs due to a recent mechanical failure of a valve. Craig Unit 1 went into an outage on December 19, 2025, and the Craig Unit 1 Owners will need to repair the Unit before they can ensure it is available to operate.[7] In response to the Order, 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."[8]

16. The Department recognized the difficulties associated with resuming operations at coal-fired facilities that have been retired:

> 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 [the Craig Unit 1 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.[9]

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[7] Tri-State, *U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days* (Dec. 31, 2025).
[8] *Id.*
[9] Order, fn. 5.

Because Craig Unit 1 was in an outage due to a mechanical failure at the time the Order was issued, the Craig Unit 1 Owners face some of the same "practical issues" and "associated challenges" in repairing the facility that they would have faced in reviving a retired facility. Due to the outage, "continuous operation" as envisioned by the Order is no longer possible, and the risks detailed in footnote 5 could manifest as additional costs that are passed on to customers in the form of higher electric bills.

17. As illustrated by both the analysis performed by Grid Strategies and the current closure due to a mechanical failure, 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" noted by Tri-State that will be necessary to extend the life of Craig Unit 1.

18. As the operator of Craig Unit 1, Tri-State will incur higher costs to serve its member utility cooperatives. It is unclear exactly how Tri-State will recover these costs, but it is likely that costs will be passed on to rural electrical cooperative consumers. According to Tri-State's Chief Executive Officer Duane Highley:

> 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.[10]

19. 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 Order is not in the public interest for the

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[10] Tri-State, *U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days* (Dec. 31, 2025).

State of Colorado and it is likely 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 23rd day of January , 2026 at 5:16 PM.

Joseph Pereira

Joseph Pereira

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 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**

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

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**DIRECT TESTIMONY AND ATTACHMENTS OF
BRIAN L. THOMPSON
ON BEHALF OF
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.**



**December 1, 2023**

## Table of Contents

# ATTACHMENTS

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| BLT-1 | Statement of Qualifications for Brian L. Thompson |

## I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

**Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A: My name is Brian Thompson. My business address is 1100 West 116th Avenue, Westminster, CO 80234.

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

A: I am employed by Tri-State Generation and Transmission Association, Inc. ("Tri-State") as Resource Planning Manager.

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

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

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

A: Yes. My Statement of Qualifications is attached to my testimony as **Attachment BLT-1**.

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

A: I have 16 years of experience in the electric utility industry. I manage the resource planning group at Tri-State. We are responsible for short-term and long-term modeling of the Tri-State system, including scenario and portfolio modeling associated with the ERP/IRP process. Previously, I held the following positions at Tri-State: Associate Real Time Marketer, Senior Energy Portfolio Analyst, Term Marketer, and Senior Engineer Resource Planning. I have a Bachelor of Science in Manufacturing Engineering Technology from Brigham Young University.

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

A: My testimony addresses the 2023 Electric Resource Plan ("ERP") model set-up based on the Tri-State system topology and key data input assumptions for Tri-State's Phase I ERP, including generic resource parameters, as well as summarizes third-party study results.

**Q: ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR DIRECT TESTIMONY?**

A: Yes, as part of my Direct Testimony, I am sponsoring the following attachments:

- Attachment BLT-1: Statement of Qualifications for Brian L. Thompson

## II. <u>TRI-STATE'S APPROACH TO MODELING</u>

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

A**:** In this section of my Direct Testimony, I describe the systems and analytical methodologies utilized by Tri-State to develop its 2023 ERP, including the modeling software used for expansion plan and dispatch modeling.

**Q**: **WHAT MODELING TOOL IS BEING USED IN THE 2023 ERP?**

A**:** Tri-State is continuing to use EnCompass software for the 2023 ERP, which was also utilized for Phase II of the 2020 ERP.

**Q: PLEASE DESCRIBE THE SYSTEMS AND ANALYTICAL METHODOLOGIES EMPLOYED TO DEVELOP THE 2023 ERP.**

A: The ERP Report (**Attachment LKT-1**) describes the systems Tri-State utilized for modeling the 2023 ERP and it also identifies the flow of input and output data between each system. As stated above, Tri-State utilizes EnCompass software for the expansion plan and dispatch modeling, as was done for Phase II of the

2020 ERP. The modeling setup is reflective of Tri-State's four-state system and location of our generation, load pockets, markets, transmission availability and constraints, and power flows between regions (visually represented in **Attachment** LKT-13 ~~**B-6** of the ERP Report (**Attachment LKT-1**)).~~ The system topology is largely similar to what was modeled in Phase II of the 2020 ERP, with three updates:

- Assumed energy transfer capability from the Eastern Colorado ("ECO") to New Mexico ("NM") planning regions was modified from 200 MW to 191 MW.
- 100 MW of energy transfer capability, at an incremental cost of $8.06/MWh, was added from the NM to the ECO planning region.
- 76 MW of energy transfer capacity, at an incremental cost of $2.39/MWh, was added from the ECO to Western Colorado ("WCO") planning region.

In addition to the base modeling set-up to reflect the Tri-State system, numerous financial, operational, and environmental data assumptions are input into the model. Once the topography design and all input assumptions are input and tested in EnCompass, scenario modeling can begin.

**Q: PLEASE PROVIDE AN OVERVIEW OF TRI-STATE'S RESOURCE PLAN SCENARIO MODELING PROCESS.**

A: Tri-State models several resource plan scenarios. Each scenario is grounded in the base modeling assumptions, but with unique modeling assumptions applied as identified in **Attachment** LKT-10 ~~**B-3** of the ERP Report (**LKT-1**).~~ In the first step, the model output results in an optimal expansion plan, which includes selected new generation needs, selected unit retirements, and levels of demand-side management. In the second step, the model dispatches the generation to meet load across the planning period based on the given expansion plan, existing resources, and system constraints. The 8760 dispatch run results in modeling outputs such as forecasted unit capacity factors, market sales and purchases, energy required, curtailments, unit starts, heat required, fuel costs, and transmission flows. The expansion plan and dispatch outputs are analyzed by Tri-State's financial and transmission planning teams to assess the forecasted financial impact of the generation and transmission requirements of each scenario.

**Q: HOW MANY SCENARIOS DID TRI-STATE MODEL?**

A: Tri-State modeled five scenarios. Each scenario reflected the base modeling assumptions, but with alterations to the assumptions based on Tri-State and stakeholders' desired parameters. The modeling of each scenario results in a unique expansion plan, dispatch, and financial result for each scenario. Following the completion of each scenario modeling run, the scenarios were tested and analyzed to evaluate their performance under two sensitivity conditions. A sensitivity analysis maintains the same expansion plan (i.e., generation units available to meet load in a given year) but modifies assumptions about the system operational environment (e.g., weather, prices) to test the performance of a scenario under potential hardship circumstances that could arise. I discuss the details of modeling sensitivities further below.

**Q: WHAT ARE SOME OF THE PRIMARY DATA INPUTS FOR SCENARIO MODELING?**

A: Data inputs fall into three core categories: 1) operational/technical, 2) financial, and

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3) environmental. Some of the primary data inputs for scenario modeling include:

- Operational/Technical: load forecast, transmission constraints, outage rates, Electric Load Carrying Capability ("ELCC"), contracts, operational data related all resources, demand-side management and beneficial electrification potential, etc.
- Financial: capital expenditure forecast, operations and maintenance ("O&M") forecast, generic resource pricing, forward pricing of power and gas curves, etc.
- Environmental: carbon emission limits.

These are a sampling of the numerous data inputs that are included in the model. A list of all modeling assumptions can be found in **Attachment** LKT-7 ~~**B** of the ERP Report~~ ~~(**LKT-1**)~~.

**Q: PLEASE IDENTIFY THE MOST SIGNIFICANT UPDATES TO MODELING INPUT ASSUMPTIONS FOR THE 2023 ERP.**

A: Tri-State reviews all of the operational, financial, and environmental data inputs to assess the need for updates or modification based on current operating conditions and policy requirements. The significant modeling modifications of note include:

- Planning Reserve Margin ("PRM") adjustment, starting at 22% and transitioning to 30.5% after Craig 3 retires;
- Updated ELCC values for wind, solar, and storage, and capacity credit for thermal units;
- Updated load forecast that removes exiting Members' loads and loads to be

served through Partial Requirements;

- Numerous updated financial assumptions, such as decommission cost, generic resource pricing, fixed and variable O&M costs, and the forecast of capital expenditures; and
- Inclusion of several new innovative technologies not previously modeled by Tri-State for the model to evaluate.

**Q: WHAT OUTPUTS RESULT FROM THE ERP MODELING FOR EACH SCENARIO?**

A: Through the modeling, we are able to forecast our resource mix, new resource additions, financial and environmental impacts, and the level of reliability achieved by each scenario, among other outputs. The modeling results for each scenario are shown in the ERP Report (**LKT-1**).

## III. <u>STUDIES SUPPORTING TRI-STATE'S PHASE I MODELING</u>

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

A: In this section of my Direct Testimony, I provide a description of the third-party studies and analyses supporting the 2023 ERP Phase I.

**Q: PLEASE PROVIDE AN OVERVIEW OF THE STUDIES SUPPORTING TRI-STATE'S PHASE I MODELING.**

A: There were four studies completed to inform Tri-State's 2023 ERP modeling, these include:

- <u>Benchmarking Analysis</u>: This study was completed by Black & Veatch in October 2023. It compares existing resources and generic resources, in regard to cost and performance. This study is provided as **Attachment** LKT-30 **~~G-~~**

~~**2** of the ERP Report (**LKT-1**).~~

- <u>ELCC and PRM Study</u>: Tri-State engaged Astrape to perform an ELCC Study for establishing ELCCs for solar, wind, and storage at various penetration levels, and capacity credits for thermal resources, as well as for establishing an appropriate PRM. This study was completed in August 2023 and is provided as **Attachment** LKT-29 ~~**G-1** of the ERP Report (**LKT-1**).~~
- <u>IRA Scenario Reliability Evaluation</u>: Astrape performed a supplemental analysis of the IRA Scenario's reliability in year 2032 of the planning period. This analysis is provided as **Attachment** LKT-32 ~~**G-4** of the ERP Report (**LKT-1**).~~
- <u>DSM Potential Study and BE Potential Study</u>: Mesa Point updated the 2020 Potential Studies in May 2023 to refresh the level of Demand-Side Management ("DSM") energy savings and beneficial electrification ("BE") potential within the Tri-System resulting from the exit of three Members from the system, updated equipment use and saturations, as well as updated avoided costs, emissions rates, and social cost of carbon. This study is provided as **Attachment** LKT-31 ~~**G-3** of the ERP Report (**LKT-1**).~~

**a. <u>Benchmarking Analysis</u>**

**Q: PLEASE DESCRIBE THE BENCHMARKING ANALYSIS.**

A: Tri-State engaged Black & Veatch ("B&V") to perform an analysis of cost and performance of existing owned resources, contracted resources, and generic resources. The study provides a resource ranking for each existing and generic resource, with and without sunk costs. Key insights from the B&V's Benchmarking Analysis include:

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- On a Levelized Cost of Energy ("LCOE") basis, wind and solar PPAs and build-transfers, and pumped storage resources are the lowest cost;[1] and
- On a Levelized Cost of Capacity ("LCOC") basis, simple cycle combustion turbine resources are the lowest cost.[2]

Not surprisingly, the study acknowledges that sunk costs (depreciation, decommissioning, etc.) are a significant driver in the cost-effectiveness of Tri-State owned resources.[3]

**Q: HOW DO THE RESULTS OF THE BENCHMARKING ANALYSIS INFORM TRI-STATE'S ERP APPLICATION?**

A: The Benchmarking Analysis identifies the levelized cost of each resource in Tri-State's fleet, as well as the levelized cost of potential new generic resources to be added to our fleet and identifies how they perform in comparison to one another. These results offer the opportunity for Tri-State to assess which units are out-performing others, based on certain factors. While the benchmarking results are informative, resource plan modeling is able to take into consideration a number of key assumptions, including environmental and transmission constraints which ensures a comprehensive approach to resource planning analysis.

**b. <u>ELCC and PRM Study</u>**

**Q: PLEASE DESCRIBE THE ELCC COMPONENT OF THE ASTRAPE STUDY.**

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

storage resources on the Tri-State system given an anticipated resource mix, and capacity credits for thermal units. Applying appropriate ELCCs, represented as a percent of nameplate capacity, enables calculation of the amount of dependable capacity that can be counted on by the system for resource adequacy purposes. The primary result of ELCC Study is a three-dimensional matrix of portfolio capacity values from which average and marginal ELCCs can be determined for any level of penetration of solar, wind, and batteries. Astrape provided Tri-State ELCCs for Tri-State's anticipated resource mix but also provided a tool to enable calculation of the average and marginal ELCCs for a given penetration level of solar, wind, and batteries in each scenario modeled in the event any scenario deviated substantially from the anticipated mix.

**Q: HOW IS THE ELCC METHODOLOGY USED IN TRI-STATE'S PHASE I MODELING?**

A: As resource penetrations increase over time, the technology-specific ELCCs decline. The appropriate ELCC is applied in EnCompass for each existing and new generating unit based on the level of installed capacity of the technology, as shown in **Table BLT-D-1**. The ELCC values result from the Astrape Study.

**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% |

**Q: DID TRI-STATE PREVIEW THE ELCC METHODOLOGY AND RESULTS WITH STAKEHOLDERS PRIOR TO PERFORMING SCENARIO MODELING?**

A: Yes. Tri-State committed to hold at least two meetings with interested stakeholders in advance of beginning Phase I modeling to seek input on ELCCs.[4] Ultimately, five discussions were convened on this topic. Tri-State first shared its approach to the ELCC Study during a meeting with stakeholders on January 17, 2023. During that initial meeting, Tri-State indicated its intention to calculate ELCC values based on a deterministic approximation method developed by the National Renewable Energy Laboratory ("NREL"). On February 23, 2023, Tri-State again met with stakeholders to share updates to the ELCC calculations. However, during a meeting on March 14, 2023, stakeholders questioned whether a probabilistic method for determining ELCCs could be used instead of the NREL method. On

[4] 2020 ERP Settlement Agreement, Section 3.11.13.

April 24, 2023, Tri-State met with stakeholders again to discuss two possible paths forward for the ELCC Study: (1) one that would require several months to hire a third-party consultant to complete a probabilistic study for Phase I, and (2) one that would maintain the NREL method for Phase I and update ELCCs using a probabilistic study in advance of Phase II. Stakeholders indicated preference for a probabilistic study to be performed for Phase I. Tri-State met with stakeholders on this topic again on July 19, 2023 to present the results of the probabilistic study completed by Astrape.

**Q: PLEASE DESCRIBE THE ELEMENT OF THE ASTRAPE STUDY RELATING TO PRM.**

A: The study completed by Astrape also calculated a PRM for Phase I of the 2023 ERP. Astrape modeled the system using thousands of simulations varying weather, hourly and peak loads, and unit outages, with the calculated PRM being based on the weighted average results. The result being a PRM of 22 percent, transitioning to 30.5 percent after retirement of Craig Station.[5]

Some of the factors noted by Astrape in their study that influenced the PRM include:

- Impact of "shaft risk," which is the risk associated with the potential loss of units that are large relative to peak load. With Tri-State's load being reduced by approximately one-third due to Member exits and the Craig Station retiring, more risk relative to load is placed on the remaining

[5] **Attachment** ~~**G-1**,~~, pg. 67. LKT-29

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dispatchable units.

- The PRM 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.

**c. IRA Scenario Reliability Evaluation**

**Q: PLEASE DESCRIBE THE PURPOSE OF THE IRA SCENARIO RELIABILITY EVALUATION.**

A: Astrape was engaged by Tri-State to conducts an analysis of the IRA Scenario's reliability in 2032.

**Q: WHAT DOES THE EVALUATION SHOW?**

A: The evaluation shows that the IRA Scenario is reliable with a very low LOLE of 0.036 days/year in 2032, providing additional assurance of reliability as a result of this plan.

**d. DSM Potential Study**

**Q: PLEASE DESCRIBE THE DSM POTENTIAL STUDY.**

A: The DSM Potential Study identifies potential energy savings and associated costs for attaining energy savings under varying DSM Potential Study scenarios. The potential is derived from measure-level analysis, incentive and avoided cost assumptions, and factors related to the Tri-State system and consumer behavior. While Tri-State does not directly offer retail consumer services or programs, we work closely with our Members to facilitate their DSM program offerings and ease program administration burdens.

**Q: IS OUTPUT FROM THE DSM POTENTIAL STUDY USED TO MODEL THE**

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**COLORADO ENERGY EFFICIENCY TARGETS THAT TRI-STATE HAS COMMITTED TO STARTING IN 2023?**

A: No. Tri-State models the 2023, 2024, 2025, and 2030 EE Targets[6] as a "must-take" level of energy savings in the resource planning period ("RPP") in all 2023 ERP Phase I scenarios, for the ECO and WCO planning regions. The EE Targets are identified in **Attachment** LKT-7 ~~**B** of the ERP Report (**LKT-1**)~~. The 2025 EE Target is held constant from 2025-2029 and the 2030 target is held constant through the remainder of the planning period.

**Q: HOW ARE THE RESULTS OF THE DSM POTENTIAL STUDY USED IN TRI-STATE'S 2023 ERP PHASE I MODELING?**

A: For any ERP scenarios that allows for either deeper levels of energy savings in ECO and WCO, or DSM as a selectable option for the NM or Wyoming/West Nebraska ("WYO/WNE") regions, the DSM Potential Study determines the level of energy savings assumed. Tranches of energy savings opportunity are selectable only based on the DSM Potential Study scenario levels (e.g., Low, Moderate, etc.). The costs to achieve the level of assumed energy savings also reflects input from Tri-State DSM program staff.

**e. <u>BE Potential Study</u>**

**Q: PLEASE DESCRIBE TRI-STATE'S BE POTENTIAL STUDY.**

A: The BE Potential Study identifies potential load growth opportunities from electrification and associated costs for attaining the additional load under varying

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[6] 2020 ERP Settlement Agreement, section 3.11.9.

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BE Potential Study scenarios. The potential is derived from measure-level analysis, incentive and avoided cost assumptions, and factors related to the Tri-State system and consumer behavior. While Tri-State does not directly offer retail consumer services or programs, we do work closely with our members to facilitate their BE program offerings and ease program administration burdens.

**Q: HOW ARE THE RESULTS OF THE BE POTENTIAL STUDY USED IN TRI-STATE'S PHASE I MODELING?**

A: The BE Potential Study determines the level of new load assumed based on study's scenario levels (e.g., Low, Moderate, etc.). For all scenarios in the 2023 ERP Phase I, Tri-State's load forecast is adjusted to reflect inclusion of the Achievement-Moderate level of BE. This approach is pursuant to the 2020 ERP Phase I Unopposed Comprehensive Settlement Agreement in Proceeding No. 20A-0528E ("2020 ERP Settlement Agreement").[7]

**Q: DID TRI-STATE FULFILL ITS COMMITMENT TO HOLD STAKEHOLDER MEETINGS ON BE PRIOR TO MODELING?**

A: Yes. Pursuant to 2020 ERP Phase I Settlement Agreement, Tri-State held two stakeholder meetings on BE best practices in advance of the 2023 ERP modeling, as identified in the ERP Report (**Attachment LKT-1**).

## IV. GENERIC RESOURCE MODELING

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

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.

resources modeled in the ERP**.**

**Q: PLEASE DESCRIBE TRI-STATE'S APPROACH TO GENERIC RESOURCES.**

A: New to the 2023 ERP Phase I, Tri-State included several new emerging technologies as generic resource options available for scenario modeling. Tri-State also held meetings with stakeholders, prior to modeling, to share data and assumptions for both new and existing generic resource options.[8] Tri-State also refreshed data and assumptions for the generic resource types that had been modeled in the 2020 ERP.

**Q: HOW ARE GENERIC RESOURCES MODELED IN THE ERP?**

A: In expansion plan modeling in EnCompass, a given scenario results in the selection of a unique set of generic resource types, locations, and target commercial operation dates ("CODs"). The modeling assesses a variety of factors in determining the expansion plan needed to meet Tri-State system load and PRM over the resource planning period. Such factors include, but are not limited to, financial assumptions regarding resource costs, resource operational parameters, and environmental characteristics of the available technologies. The expansion plan output reflects the optimal solution for economically meeting the numerous constraints input into the model, such as transmission and new build constraints (**Attachment** LKT-8 AND LKT-9 ~~**B-1, B-2** of the ERP Report (**LKT-1**)),~~ emissions reduction targets, and others.[9]

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[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.

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**Q: WHAT NEW TECHNOLOGIES DID TRI-STATE INCLUDE IN ITS GENERIC RESOURCE DATASET?**

A: New technologies modeled in the Phase I 2023 ERP are identified in **Attachment** LKT-16 ~~**C-2** of the ERP Report (**LKT-1**)~~ and include:

- 10-hour Battery Storage
- Molten Salt Long-Term Storage;
- Iron Air Multi-Day Storage;
- Advanced and Enhanced Geothermal;
- Green and Blue Hydrogen;
- Natural Gas Combined Cycle with Carbon Capture and Sequestration ("NGCCS"); and
- Small Modular Reactors ("SMRs").

Key financial, operational, and environmental assumptions about each technology type are included in **Attachment** LKT-16 ~~**C-2** of the ERP Report (**LKT-1**).~~ The sources for this data include third-party experts, technology vendors, and trusted industry research sources such as the National Laboratories. Not all technologies are assumed to be deployment-ready during the first year of the RPP. Additionally, several of the new technologies were not selected in any of the scenario expansion plans.

**Q: HOW DID TRI-STATE CONSIDER THE IMPACT OF FEDERAL FUNDING OPPORTUNITIES IN PRICING GENERIC RESOURCES?**

A: The financial assumptions for the generic resources reflect applicable available federal tax incentives, including the Investment Tax Credit ("ITC") or Production Tax Credit ("PTC"). The following technology types are assumed to be eligible for a 40 percent ITC:

- battery component of hybrid build-transfer;
- 4- and 10-hr batteries;
- pumped storage;
- advanced geothermal;
- enhanced geothermal baseload;
- enhanced geothermal with 12-hour storage;
- green hydrogen; and
- SMRs.

Molten salt and iron air technologies are assumed to be eligible for a 50 percent ITC, due to the expectation that they could qualify for the domestic content bonus credit.

The following technology types are assumed to be eligible for an energy-production based PTC:

- solar
- wind;
- solar and wind hybrids;
- blue hydrogen; and
- NGCCS.

For both existing and generic resources, that were assumed to be build-transfer projects owned by Tri-State, it is assumed that Tri-State would be eligible for direct pay of tax credits, as described in the Direct Testimony of Lisa Tiffin.

## V. <u>MARKET DEPTH ASSUMPTIONS</u>

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

A: In this section of my Direct Testimony, I discuss how Tri-State's planned market participation is reflected in the modeling approach.

**Q: HOW DOES TRI-STATE'S MODELING ACCOUNT FOR TRI-STATE'S CURRENT AND PLANNED MARKET PARTICIPATION?**

A: As identified in Proceeding No. 23M-0195E, Tri-State plans for its loads, resources, and transmission system in the Western Area Power Administration Colorado-Missouri Region ("WACM") balancing authority to join the Southwest Power Pool ("SPP") Regional Transmission Organization ("RTO") in the Western Interconnection on April 1, 2026. In Tri-State's 2023 ERP Phase I modeling, we simulate the impact of this portion of our system entering the market by increasing market sales and purchase depths starting in 2026. Additional detail on the specific depths and assumptions can be found in **Attachment** LKT-7 ~~**B** of the ERP Report (**LKT-1**).~~

**Q: IS THIS A REASONABLE MODELING APPROACH?**

A: Yes. Because Tri-State does not yet have the capacity to employ a nodal model, adjusting market depth parameters is the best approach available. As Tri-State continues to make progress toward SPP RTO market participation for its WACM load and resources, we anticipate transitioning our EnCompass model to employ a nodal approach for the 2027 ERP.

## VI. <u>SENSITIVITY ANALYSES</u>

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

A: In this section of my Direct Testimony, I discuss the two sensitivity analyses that Tri-State modeled for each scenario.

**Q: WHAT SENSITIVITIES DID TRI-STATE MODEL?**

A: Tri-State assessed each scenario's performance under two sensitivity analyses—one that simulated extreme weather event ("EWE") conditions and one that evaluated High Gas prices.

**Q: PLEASE DESCRIBE THE SENSITIVITY ANALYSES TRI-STATE COMPLETED FOR EACH SCENARIO.**

A: For each scenario, Tri-State tested system performance under both EWE and High Gas conditions, separately. For the EWE sensitivity, transmission, load, renewable and thermal generation, and gas and power market prices were stressed (as described in **Attachment** LKT-12 ~~**B-5** of the ERP Report (**LKT-1**)~~) for a one-week period in each winter and summer season during the Resource Acquisition Period ("RAP") to evaluate each scenario's performance under those conditions. Each scenario maintains its base expansion plan throughout the sensitivity analyses, but each scenario is re-dispatched in EnCompass with the stressed parameters to model the impact of an extreme weather or high gas event.

The approach to EWE sensitivity modeling in Phase I of the 2023 ERP is different from the approach in Phase II of the 2020 ERP in that the EWE stress assumptions are included in the modeling of each scenario's expansion plan. This approach resolved the issue that occurred in the 2020 ERP Phase II of scenarios not meeting the Level II reliability metrics under initial modeling runs due to lack of expansion plan visibility into the EWE parameters. The base dispatch for each scenario does not reflect the EWE stress, to enable assessment of the financial results for each scenario under assumed normal system conditions.

For the High Gas sensitivity, stressed gas and power market prices[10] were applied in the modeling to evaluate each scenario's financial performance under that condition (as described in **Attachment** LKT-25 ~~**E** of the ERP Report (**LKT-1**)~~), providing another look at dispatch results.

**Q: DID TRI-STATE ENGAGE STAKEHOLDERS IN IDENTIFYING AND DEVELOPING THE SENSITIVITIES MODELED?**

A: Yes. Tri-State held several meetings with interested stakeholders between January 17 and July 19, 2023, prior to beginning modeling, to discuss potential scenarios and sensitivities to be modeled and Tri-State's approach to EWE data and related reliability metrics. During those meetings, Tri-State reviewed potential scenarios and sensitivities and made adjustments based on stakeholder feedback. Tri-State also shared its approach to the EWE stress, detail on historical EWE data evaluated, planned EWE resource and transmission stresses and how each differed from the 2020 ERP Phase II EWE modeling, and provided options for potential approaches to the EWE load stress for stakeholder input. These meetings are identified in ERP Report (**LKT-1**).

**Q: WHAT ARE THE KEY ASSUMPTIONS FOR THE EWE SENSITIVITY?**

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[10] Market prices are provided by a third-party vendor, Horizons Energy—a analytics, data, and consulting company.

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A: The EWE sensitivity simulates a 168-hour period in the summer and in the winter where extreme weather occurs, during a forecasted peak load period and resource availability and system operations are constrained. The EWE stress assumptions are described in detail within **Attachment** LKT-12 ~~**B-5** of the ERP Report (**LKT-1**)~~ and reflect modifications from historical EWE conditions to address the Commission's statement in Decision No. C23-0437 that "…an EWE that merely replicates past heat waves or winter storms might be an insufficient test of the resource adequacy of the portfolios under consideration in future ERPs."[11]

**Q: PLEASE DESCRIBE THE DATA INPUTS FOR THE EWE SENSITIVITY.**

A: Tri-State primarily utilized historical data from EWE periods to develop EWE sensitivity stresses. These data informed the length of the EWE, the initial resource profiles, and expected transmission constraints. The following periods of historical EWEs were evaluated:

- July 2018 Heat Wave: 7/7-7/11 (5-day event)
- July 2022 Heat Wave: 7/17-7/19 (3-day event)
- Feb 2021 Winter Storm Uri: 2/13-2/17 (5-day event)
- Dec 2022 Winter Storm Elliot: 12/21-12/26 (6-day event)

Tri-State also utilized renewable resource performance profiles from some of these events, where available for existing resources on the Tri-State system. EWE stress data is applied on a regional basis, reflective of Tri-State system diversity. From these data, Tri-State made any necessary adjustments to reflect a

[11] Decision No. C23-0437, at ¶ 57.

reasonable time period for events (month of occurrence and length of days), to sync profiles of resource stresses to load as both are impacted by weather, and to ensure a robust but reasonable stress not solely based on past weather conditions. The approach to these adjustments is described in **Attachment** ~~**B-5**~~ LKT-12 ~~of the ERP Report (**LKT-1**).~~

**Q: BEYOND THE CHANGE IN APPROACH TO MODELING, WHAT INPUT ASSUMPTIONS WERE CHANGED FOR EWE SENSIVITIES SINCE THE 2020 ERP?**

A: Nearly all of the EWE modeling assumptions were modified for the 2023 ERP. Data input assumption modifications for the EWE sensitivity include:

- **Length of EWE:** The timeframe for each EWE was shortened from two weeks to one week (168 hrs).
- **Load Stress:** Instead of a 90 percent confidence interval load stress applied equally to each hour, the load stress was based on a statistical model difference between the actual storm event weather in terms of precipitation for the month of the event and temperatures and 10-year weatherized normal weather by region. The EWE week was grossed up by the difference and the shape of the storm replaced the normalized shape used for the storm week. EWE dates were selected such that the demand peak in the months with EWE overlapped with the peak date of the storm. Please see the Direct Testimony of Lisa A. Lynn for additional detail on the load forecast assumptions and the extreme weather load forecasting methodology.

- **Renewable Resource Stress:** Renewable resource stresses were based on historical actual performance of renewable resources during prior EWEs where available, as well as actual wind speed or solar irradiance during prior EWEs. Renewables were stressed by an additional percentage, by region, for 72 hours during the peak period of the EWE to reflect that future events can be more severe than past events.
- **Thermal Resource Stress:** Outages and derates for existing thermal units were applied based on actual performance during historical actual EWEs.
- **Transmission Constraint Stress:** The TOT 3 transmission path (a corridor between southern Wyoming and northern Colorado) was reduced to 75 percent of Tri-State's share of its transfer capacity for three days during the winter EWE, and six hours (HE16-HE21) of every summer EWE period.
- **Limited Availability of Market Purchases:** Market purchases were modeled in the dispatch as available during limited hours of each EWE.

Each of these stresses are described in **Attachment** LKT-12 ~~**B-5** to the ERP Report (**LKT-1**).~~

**Q: DID TRI-STATE EVALUATE THE POTENTIAL FOR APPLYING A PROBABILISTIC MODELING APPROACH TO EWE?**

A: Given the short period of time between receipt of the 2020 ERP Phase II decision[12] and the start of 2023 ERP Phase I modeling, Tri-State was not able to consider the pursuit of probabilistic modeling for the EWE sensitivity. Tri-State will continue

[12] Decision No. C23-0437, at ¶56 (Proceeding No. 20A-0528E).

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to evaluate opportunities to further enhance approaches to EWE sensitivity modeling over time.

**Q: WHAT ARE THE KEY ASSUMPTIONS FOR THE HIGH GAS SENSITIVITY?**

A: The only modification for the High Gas Sensitivity is to stress the gas and electric prices, to assess scenario performance. High Gas Sensitivity assumptions and results are provided in **Attachment** LKT-25 ~~**E** of the ERP Report (**LKT-1**).~~

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

A: Yes.

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

**PROCEEDING NO. 23A-____E**

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

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**VERIFICATION**

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STATE OF ____COLORADO____ )
) ss:
COUNTY OF __ADAMS________ )

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

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

TRI-STATE GENERATION AND
TRANSMISSION ASSOCIATION, INC.

By:
Brian Thompson
Resource Planning Manager

Witness my hand and official seal.

Notary Public

My Commission expires: 12/28/25.

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

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit E: CoPUC, Decision No. C25-0612, issued on August 26, 2025,
in Proceeding No. 23A-0585E.

Decision No. C25-0612

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

PROCEEDING NO. 23A-0585E

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

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**PHASE II COMMISSION DECISION
APPROVING COST-EFFECTIVE RESOURCE PLAN,
GRANTING MOTION TO WAIVE CERTAIN
CPCN FILING REQUIREMENTS, AND
DENYING MOTION TO ENFORCE SETTLEMENT,
STRIKE COMMENTS, AND REQUIRE NEW MODELING**

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Issued Date: August 26, 2025
Adopted Date: August 1, 2025

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# I. <u>BY THE COMMISSION</u>

## A. Statement

1. On April 11, 2025, Tri-State Generation and Transmission Association, Inc. (Tri-State) filed its Electric Resource Plan ("ERP") Implementation Report in Phase II of this ERP proceeding in accordance with the Commission's ERP Rules set forth in 4 *Code of Colorado Regulations* 723-3-3600 *et seq.*, and specifically Rule 3605. The ERP Implementation Report

summarizes the bid evaluation and selection resulting from Tri-State's competitive solicitations for new utility resources pursuant to the Commission's Phase I decision in this same ERP proceeding.

2. By this Phase II Decision, we establish Tri-State's Preferred Portfolio (also called Portfolio 4 or FLEXSR) as a cost-effective resource plan. The plan includes the acquisition of 400 MW of wind generation, 200 MW of solar generation, 650 MW of storage, and 307 MW of gas-fired generation between 2026 and 2031. Phase II of Tri-State's ERP also entails the replacement of the gas turbines at Tri-State's J.M. Shafer plant ("Shafer") to improve its capacity contributions. Importantly, the Preferred Portfolio maintains the previously announced retirements of certain coal-fired generation facilities at Tri-State's Craig and Springerville plants. Based on the record in this Proceeding and all required considerations, including those in §§ 40-2-123, 40-2-124, 40-2-129, and 40-2-134, C.R.S., and as set forth in Rule 3605, we conclude that the Preferred Portfolio includes clean energy resources that can be acquired at a reasonable cost and rate impact and with appropriate consideration to: Best Value Employment Metrics ("BVEM"); issues of energy security, economic prosperity, and environmental protection; and the energy policy goals of the State of Colorado.

3. We also grant the Motion for Partial Waiver of Rules 3102 and 3103 in Connection with a Gas Resource Addition and Craig Station Retirement ("CPCN Motion") filed by Tri-State on April 15, 2025.

4. We further deny the Motion to Enforce Settlement Agreement, Strike Comments, and Require New Modeling ("CC/WRA Motion") filed jointly by the National Resources Defense Council and Sierra Club (together the "Conservation Coalition") and Western Resource Advocates ("WRA") on June 18, 2025, consistent with the discussion below.

## B. Discussion

### 1. Electric Resource Planning for Tri-State

5. This Proceeding addresses the second ERP application filed by Tri-State since the enactment of Senate Bill ("SB") 19-236. That statute directed the Commission to promulgate ERP rules for wholesale electric cooperatives such as Tri-State, considering whether such cooperatives serve a multistate operational jurisdiction, have a not-for-profit ownership structure, and have a resource plan that meets the energy policy goals of the State.[1]

6. The Commission promulgated Rule 3605 in Proceeding No. 19R-0408E in accordance with SB 19-236.[2] Under that rule, in Phase I of an ERP, the wholesale electric cooperative assesses the need for additional resources given its energy and demand forecasts, existing resources, planning reserve margins, and other factors, including statewide goals to reduce greenhouse gas ("GHG") emissions. The wholesale electric cooperative is directed to set forth a plan for acquiring resources either through a competitive process or an alternative method of resource acquisition, and to provide bid policies, requests for proposals (RFPs), model contracts, and criteria for bid evaluation, as necessary. Phase II begins after the Commission issues its Phase I decision.

7. Pursuant to Rule 3605(h)(II), the Commission must consider certain public interest and statutory criteria in its Phase II decision approving, conditioning, modifying, or rejecting the wholesale electric cooperative's preferred cost-effective resource plan. That is, pursuant to §§ 40-2-123 and 40-2-124, C.R.S., the Commission considers renewable energy resources, energy efficient technologies, and resources that affect employment and long-term economic viability of

[1] *See* § 40-2-134, C.R.S.
[2] Proceeding No. 19R-0408E, Decision No. C20-0155, issued March 10, 2020.

Colorado communities. The Commission further considers resources that, among other characteristics, provide beneficial contributions to energy security, economic prosperity, environmental protection, and insulation from fuel price increases. Additionally, the Commission determines whether the wholesale electric cooperative has provided sufficient BVEM information in accordance with § 40-2-129, C.R.S.; certified compliance with the objective standards for the review of such metrics based on the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility. The wholesale electric cooperative must request BVEM information from bidders through its RFP process, including information on training programs, employment of Colorado workers, and long-term career opportunities.

8. With respect to the establishment of a cost-effective resource plan in Phase II, the Commission also considers the net present value of revenue requirements ("NPVRR") for the potential resource portfolios to be established as the cost-effective resource plan, with and without the application of the social cost of carbon dioxide emissions pursuant to § 40-3.2-106(3), C.R.S. Ultimately, in accordance with § 40-2-134, C.R.S., the Commission determines whether the final cost-effective resource plan meets Colorado's energy policy goals.

### 2. Phase I Procedural Background

9. On December 1, 2023, Tri-State filed its 2023 ERP in this Proceeding, initiating Phase I.

10. A full procedural history of Phase I is set forth in Decision No. R24-0602 ("Phase I Decision").

11. By Decision No. R24-0080-I, issued by Administrative Law Judge ("ALJ") Aviv Segev, the Commission established the parties to this proceeding: Tri-State; Trial Staff of

the Colorado Public Utilities Commission ("Staff"); the Colorado Office of the Utility Consumer Advocate ("UCA"); the Colorado Energy Office ("CEO"); the City of Craig and Moffat County; Poudre Valley Rural Electric Association, Inc.; Highline Electric Association; K.C. Electric Association ("KC Electric"); San Isabel Electric Association, Inc. ("San Isabel"); Southeast Colorado Power Association; and Y-W Electric Association, Inc.; Big Horn Rural Electric Company, Carbon Power & Light, Inc., High West Energy Inc., Wheatland Rural Electric Association, Wyrulec Company, Inc., Niobrara Electric Association, High Plains Power, Inc., and Garland Light & Power Co. (collectively "Wyoming Cooperatives"); Colorado Solar and Storage Association ("COSSA") and Solar Energy Industries Association (collectively "COSSA/SEIA"); the Conservation Coalition; Colorado Independent Energy Association ("CIEA"); Southwest Energy Efficiency Project; Interwest Energy Alliance; and WRA.

12. The Phase I Decision, also rendered by ALJ Segev, approved a comprehensive and unopposed Settlement Agreement that resolved all contested issues in Phase I. The ALJ's recommended decision became the Phase I decision of the Commission on September 11, 2024, without modification.

13. The Settlement Agreement approved by the Phase I Decision contemplates three concurrent solicitations (RFPs) for Phase II, each meeting certain specifications: a Dispatchable RFP; a Standalone Storage RFP, and a Renewable RFP. The Settling Parties agreed that the Commission should approve a Phase II portfolio from among a set of defined portfolios to be modeled by Tri-State pursuant to the terms of the Settlement Agreement.[3] These portfolios include: Tri-State's Preferred Portfolio; the Preferred Portfolio with specific modifications; an "unconstrained portfolio that allows all resources to be selected by the model;" an additional

[3] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 4.2, pp. 5-9.

portfolio of Tri-State's choosing; and a "Contingent No New Gas Portfolio" if the other portfolios modeled select new gas-fired resources.[4] Notably, a provision in the Settlement Agreement requires Tri-State to solicit bids for a gas plant within Moffat County.[5] The Settlement Agreement also includes a provision that Tri-State will apply a $1/MWh price improvement over the life of the proposed project or contract in the evaluation and modeling of bids located in Moffat County.[6] The Settlement Agreement further sets out additional filing requirements for the Implementation Report to be filed in Phase II ("ERP Implementation Report") and spells out Tri-State's commitments related to processes and actions in its next ERP to be filed in 2027.

14. Tri-State issued the three RFPs on September 13, 2024, commencing Phase II. Tri-State received 145 individual eligible bid proposals as reported in its "45-Day Report" filed on December 12, 2024.

### C. Tri-State's ERP Implementation Report

15. Rule 3605(h)(I) lays out the minimum requirements for the report that is filed by the wholesale electric cooperative in Phase II. Tri-State must present cost-effective resource plans in accordance with the Commission's Phase I decision and shall identify its preferred cost-effective resource plan. The report must: (1) apply the cost of carbon dioxide emissions to all existing and new utility resources in its modeling of the costs and benefits of all resource plans as required by the Commission's decision in Phase I; (2) present a calculation of the NPVRR for each portfolio required by the Commission's decision in Phase I and the NPVRR for each existing and new utility resource included in the portfolio, as well as the total cost of carbon dioxide emissions of the total portfolio, calculated using the cost of carbon set forth in the Commission's decision in Phase I and

[4] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 4.3, pp. 9-11.
[5] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 4.2.6.1, p. 7.
[6] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 5.4.1, pp. 24-25.

calculated without using the cost of carbon dioxide emissions; (3) present, for each portfolio, the net present value calculation of the total cost of carbon dioxide emissions calculated by multiplying the total emissions of that portfolio by the cost of carbon dioxide; and (4) provide the Commission with the BVEM information provided by bidders.

16. The ERP Implementation Report that Tri-State filed on April 11, 2025, addresses the requirements in Rule 3605(h)(I) and the requirements in the Settlement Agreement for six modeled portfolios of 52 bids advanced to Phase II modeling. Tri-State also summarizes the factors the Commission must consider in rendering its Phase II pursuant to pursuant to Rule 3605(h)(II) with respect to each of the six modeled portfolios.

17. The six modeled portfolios include:

Portfolio 1. New ERA Expanded (NEE)
Portfolio 2. New ERA Limited Gas (NELG)
Portfolio 3. New ERA Gas Flexibility (FLEX)
Portfolio 4. FLEX Shafer Replacement (FLEXSR) "Preferred Portfolio"
Portfolio 5. No New Gas (NNG)
Portfolio 6. No New Gas Shafer Replacement (NNGSR)

18. Tri-State used EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses. The Resource Acquisition Period ("RAP") for Phase II is 2026 through 2031.

19. Tri-State explains in the ERP Implementation Report that its Preferred Portfolio, Portfolio 4, was selected for its overall performance across the established reliability, environmental, and financial categories as analyzed and described in the Report. Tri-State asserts that the portfolio meets both "Level 1" and "Level 2" Reliability Metrics. Tri-State clarifies that its Preferred Portfolio also meets Colorado emissions reduction targets for GHGs, the Colorado

Renewable Energy Standard, and the New Mexico Renewable Portfolio Standard. Tri-State further claims that it is the least-cost portfolio from the perspective of the rates its members will pay.

20. As stated above, the Preferred Portfolio comprises 1,350 MW of wind, solar, and storage resources. The Preferred Portfolio also maintains the retirement of coal capacity at Craig and Springerville by March 2031. Craig 1 is scheduled for retirement on December 31, 2025; Craig 2 is scheduled for retirement on September 30, 2028; and Craig 3 is scheduled for retirement on January 1, 2028; and Springerville 3 is scheduled for retirement on March 1, 2031.[7] The 307 MW gas combustion turbine included in the Preferred Portfolio will be located in Moffat County will have up to a 30 percent hydrogen blend capability and a planned operation date of 2029. The Preferred Portfolio further reflects Tri-State's plan to replace and upgrade the gas turbines at Shafer. According to Tri-State, the upgraded turbine replacements would require less maintenance expenses in the early four years, increase the capacity from 272 MW to 281 MW, and improve the heat rate at the plant.

21. Notably, the ERP Implementation Report presents Portfolio 6 (or "No New Gas/Shafer Replacement" or "NNGSR"), which replaces the 307 MW gas turbine project in the Preferred Portfolio with an additional 550 MW storage. Both the Preferred Portfolio and Portfolio 6 include the same 400 MW of wind, 200 MW of solar, and 650 MW of battery storage. Both portfolios also reflect the turbine replacements at Shafer.

22. In terms of environmental factors, Tri-State explains that the Phase II modeling indicates all six portfolios can achieve the Colorado GHG reduction targets in 2025, 2026, 2027,

[7] Tri-State ERP Implementation Report, Tables 7, 28, 49, 70, 91, and 112, pp. 21, 32, 43, 54, 64, 75, respectively.

and 2030. Tri-State concludes that the forecasted emissions reductions in 2030 meet the minimum statutory requirement and do not vary substantially across the six portfolios.

23. In the comparative financial analysis presented in the ERP Implementation Report, Tri-State states that the Preferred Portfolio is shown to have a lower cost (*i.e.*, the lowest NPVRR) without consideration of the social cost of emissions (or a cost that is $88 million less than Portfolio 6 or 0.5 percent). However, Portfolio 6 has a lower cost with social cost of emissions (by $329M, or 1.1 percent).

24. Tri-State explains that the Preferred Portfolio requires the least amount of resource additions with less transmission capital expenditures. Tri-State also raises concerns about the potential risk in overreliance on 4-hour batteries suggested by the resource additions in Portfolio 6. Tri-State admits that it has not yet deployed any batteries on its system. Tri-State also expects storage technologies, including longer duration storage options, to make advancements in the coming years.

25. Tri-State further states in the ERP Implementation Report that it remains in a capacity-long position until 2030. However, Tri-State explains that resource acquisitions are required through this Phase II for ensuring ongoing resource adequacy and reliability as the coal units at Craig and Springerville are retired in 2028 and 2031 and to maintain progress toward emission reductions for Colorado statutory compliance as well as for New ERA funding eligibility.[8] Tri-State explains that waiting to procure resources needed for 2030 until the 2027 ERP would not be prudent given that its Phase II process may not conclude until late 2028 or early 2029.

[8] Pursuant to the terms of the Settlement Agreement approved by the Phase I Decision, Tri-State filed a notice in this Proceeding on October 25, 2024, three days before the Phase II bid deadline, stating that Tri-State has been awarded New ERA funding from the U.S. Department of Agriculture and that the New ERA grants and loans support a clean energy transition for rural communities to achieve significant GHG reductions.

26. In terms of curtailments, Tri-State explains that none of the six portfolios result in wind curtailment costs for purchased power agreements ("PPAs"). However, significant solar curtailment costs are expected for all portfolios due to the integration of large amounts of intermittent resources into the system within a short time span. Tri-State succinctly states: "More intermittent resources leads to more curtailment, but storage additions mitigate curtailments."[9]

27. With respect to reliability, Tri-State explains that each of the six portfolios met Level 1 and 2 Reliability Metrics but that the Preferred Portfolio "achieves reliability in the most cost-effective manner."[10] Anticipating the potential interest in Portfolio 6 due to the terms of the Settlement Agreement, Tri-State states that the retirement of dispatchable coal resources cannot be affordably or reliably replaced solely with semi-dispatchable resources. The new resources, including the dispatchable gas plant in Moffat County, will provide jobs and tax base that support community vitality across many areas of Tri-State's system.

28. For transmission costing purposes, Tri-State explains that it completed interconnection optimization for the Preferred Portfolio and Portfolio 6. According to Tri-State, optimizing the Preferred Portfolio enabled the avoidance of an estimated $370 million in transmission capital expenditures during the RAP. Likewise, optimizing Portfolio 6 enabled the estimated avoidance of approximately $317 million in transmission capital expenditures during the RAP.

29. Tri-State also conducted Encompass modeling to identify three back-up bid pools. Tri-State explains that it will, to the extent necessary, utilize these backup bid pools to replace

[9] Tri-State ERP Implementation Report, p. 94.
[10] Tri-State ERP Implementation Report, p. 95.

Preferred Portfolio bids that fail. If a Preferred Portfolio bid cannot move forward, Tri-State aims to replace it with a similarly sized, similar technology type project, if possible, subject to limitations and economics. Tri-State states that upon any bid failure(s), it would utilize bids from the relevant back-up bid pool, along with the remaining viable Preferred Portfolio bids, and run a dispatch at that time to ensure continued adherence to the same affordability, reliability, and responsibility metrics and principles each Phase II portfolio was measured against. Tri-State will also: notify the Commission of any bid failures; identify steps taken to remediate the failed project, where feasible; and identify the back-up bid, or combination of backup bids, selected from the pools.

30. Finally, with respect to BVEM, Tri-State explains that Rule 3605(h)(I)(A)(iii) requires it to provide to the Commission certain BVEM information provided by bidders." The BVEM information provided by bidders whose bids were advanced to modeling is specifically provided in Attachment F-1 to the ERP Implementation Report. Tri-State explains that BVEM is a non-price factor ("NPF") analyzed by Tri-State as an element of bids' community stewardship.[11]

31. Tri-State requests that the Commission find its Preferred Portfolio to be a cost-effective resource plan and approve it through this Phase II decision. Tri-State concludes that its ERP Implementation Report provides extensive detail on the multiple portfolios modeled and "builds a clear record that supports approval of Tri-State's preferred portfolio."[12] Tri-State requests the Commission approve Tri-State's Preferred Portfolio as the final cost-effective resource plan for Phase II of the 2023 ERP, pursuant to Rule 3605(h)(II).

[11] Tri-State ERP Implementation Report, p. 13.
[12] Tri-State ERP Implementation Report, p. 95.

### D. Independent Evaluator Report

32. In its Phase I application filing, Tri-State committed to using an Independent Evaluator ("IE") "to add further assurance of consistency and fairness in its bid evaluation process for both Build Transfer and PPA agreements."[13]

33. On April 15, 2025, 1898 & Co.—the IE retained by Tri-State— filed its Phase II report. The IE states that it was responsible for confirming that: all assumptions used in the RFP were reasonable; there is no discernable bias for or against any respondent or permitted technology; all respondents have access to the same information at the same time; and all bids are evaluated using the same assumptions and criteria.[14]

34. The IE concludes that Tri-State's RFP process was conducted fairly without bias towards or against any acceptable technology or respondent. The IE further concludes that the established protocols were adhered to and that it is unaware of any improper contact between Tri-State and any bidder.

35. The IE states that it was actively engaged throughout the RFP process: reviewing all RFP documents as the process commenced; reviewing all bids submitted and the communications between Tri-State and bidders; and holding frequent meetings with Tri-State throughout the engagement. The IE states that "all assumptions used in the EnCompass modeling were reasonable, and that the overall scoring process was conducted fairly without bias towards or against any acceptable technology or respondent."[15]

[13] Hr. Ex. 101, Tiffen Direct, p. 41.
[14] IE Report, p. 1.
[15] IR Report, p. 5.

**E. APCD ERP Verification Report**

36. On May 12, 2025, the Air Pollution Control Division ("APCD") of the Colorado Department of Public Health and Environment filed a Verification Report. The APCD report indicates that House Bill 21-1266, codified, in part, at § 25-7-105, C.R.S., requires Tri-State to submit an ERP to the Commission that achieves at least an 80 percent reduction in GHG emissions associated with the Tri-State's sales to customers within Colorado by 2030, when compared to a 2005 baseline. The APCD report also states, as part of House Bill 21-1266, the APCD is required to provide verification of the GHG emissions reductions projected in the ERP.

37. APCD concludes that the emission reductions for the Preferred Portfolio are 80 percent below baseline levels. APCD explains that the modeling data provided by Tri-State was used to cross-check entries in the calculation of emissions in accordance with APCD's Verification Workbook and associated guidance.

**F. Phase II Party Comments**

**1. Staff**

38. Staff asserts that it: "does not oppose approval of Tri-State's Preferred Portfolio (Portfolio 4) but also does not oppose approval of the No New Gas version of the Preferred Portfolio (Portfolio 6)."[16] However, Staff notes that the "transmission optimization" was only applied to the Preferred Portfolio and Portfolio 6, which "makes it impossible to directly compare those portfolios to the others."[17] Staff states that the additional transmission analysis revealed significant network upgrade costs that could be avoided by modifying the modeling assumptions and, for the Preferred Portfolio, making manual changes to a subset of the selected resources.

[16] Staff Comments, p. 23.
[17] Staff Comments, p. 4.

Staff highlights that such information was not used to re-optimize the four other portfolios. Staff thus requests clarification from Tri-State on certain aspects of the transmission optimization analysis.

39. Staff also states that Tri-State's proposal to replace the gas turbines at Shafer was not examined in Phase I, and, since the Preferred Portfolio and Portfolio 6 cannot be compared to other portfolios, it is not possible to determine the cost and benefits of the Shafer turbine replacements. Staff hence asks that Tri-State provide a better process for evaluation of any similar projects in future ERPs.[18]

**2. UCA**

40. UCA supports Tri-State's Preferred Portfolio because it has the lowest PVRR and because it provides gas-fired capacity in Western Colorado.[19]

41. UCA notes, however, that Tri-State's proposal to replace the turbines at Shafer were not disclosed in Phase I. UCA also raises questions about the capacity factors for new gas units because they appear inconsistent with the reported heat rates of the plants.[20] And while UCA generally supports the inclusion of transmission costs that relate to bids, which appears in Appendix G of the ERP Implementation Report, it offers the following suggestions related to transmission.[21] First, UCA states that wind and solar can share transmission as both reach their peak outputs at different times of the day. While some additional curtailment might result from this sharing, this could easily be included in the evaluation of projects. Additionally, wind and solar can share transmission with firm resources firming the capacity. Second, Tri-State only includes its transmission analysis for Portfolios 4 and 6, and the lack of transmission analysis for

[18] Staff Comments, p. 4.
[19] UCA Comments, p. 1.
[20] UCA Comments, pp. 4-6.
[21] UCA Comments, p. 6.

the other portfolios could pose difficulties because not all transmission costs will have been similarly applied.

### 3. CEO

42. CEO requests the Commission approve Tri-State's Preferred Portfolio.[22]

43. CEO argues the Preferred Portfolio aligns with clean energy and GHG emissions reduction policy requirements and goals.[23] CEO notes that although the Preferred Portfolio includes a new gas 307 MW facility and replacement of the Shafer turbines, the turbines are being proposed as both gas- and hydrogen-capable, which presents the opportunity to transition to even lower GHG emitting resources over the long term.[24]

44. CEO also contends Tri-State's Preferred Portfolio supports Just Transition efforts in Moffat County, consistent with what Tri-State, City of Craig, and Moffat County endorsed in the Phase I Settlement Agreement. CEO states: "Co-locating gas resources in Moffat County could provide additional support to the City of Craig and Moffat County and cost-saving opportunities for Tri-State's Members."[25]

45. CEO also suggests Tri-State should use the acquisition of 650 MW of storage to gain familiarity with the technology, reduce curtailments of renewable energy resources, and minimize the use of gas and coal resources.[26]

### 4. Moffat County and City of Craig

46. Moffatt County and City of Craig "fully support" Tri-State's Preferred Portfolio and note that the two resources proposed for Moffat County—the new gas plant and a 200 MW

[22] CEO Comments, p. 13.
[23] CEO Comments, pp. 7-8.
[24] CEO Comments, p. 8.
[25] CEO Comments, pp. 10-12.
[26] CEO Comments, p. 12.

storage asset—"have the potential to provide significant tax revenues for the local community and taxing districts… while also providing multiple employment opportunities for Northwest Colorado residents, including Craig Station, Hayden Station, and coal mine workers."[27] These parties also included letters of support from the Associated Governments of Northwest Colorado and the Craig Rural Fire Protection District.

**5. San Isabel and KC Electric**

47. San Isabel Electric Association and KC Electric Association each filed comments in the form of a standard letter submitted by non-party cooperatives members of Tri-State. They support the Preferred Portfolio, stating: "This portfolio identifies bid selections that result in a plan that meets both industry-standard and heightened extreme weather reliability metrics and state GHG and renewable requirements at a lower cost than the alternative portfolios."

**6. Wyoming Cooperatives**

48. The Wyoming Cooperatives state that they worked in coordination with Tri-State to help create the Level I and Level II reliability metrics but they remain concerned about the cost it will take to meet those metrics given Colorado's environmental policies.[28] They also state that while Tri-State's Preferred Portfolio is the lowest cost modeled plan, it still comes with a projected NPVRR of $16.4 billion dollars that will be recovered from Tri-State's member cooperatives. They explain that "it was imperative that Tri-State receive funding under the New ERA Program to help mitigate rate impacts during the clean energy transition."[29] They add, however, that "even with the addition of billions of dollars of New ERA funding projected to be in place, Tri-State's

[27] Moffat County and City of Craig Comments, pp. 3-4.
[28] Wyoming Cooperatives Comments, pp. 1-2.
[29] Wyoming Cooperatives Comments, p. 2.

rate payers are facing SUBSTANTIAL wholesale rate increase projections over the next 10 years, and double digit increases from 2026 - 2028 to implement the Preferred Portfolio."[30]

### 7. Conservation Coalition

49. The Conservation Coalition objects to Commission approval of Tri-State's Preferred Portfolio and instead supports Portfolio 6. The Conservation Coalition urges Tri-State to reconsider its decision and select Portfolio 6 as its preferred plan, and, if Tri-State does not make that change, it asks the Commission to approve Portfolio 6 instead of the Portfolio 4.

50. For instance, Conservation Coalition argues that Portfolio 6 has the lowest capital costs for generation and transmission during and the lowest PVRR when including the social cost of emissions. In addition, without the social cost of emissions, Tri-State's Preferred Portfolio only has 0.5 percent advantage over Portfolio 6 during periods of "highly uncertain cost estimates in the 2030s and 2040s." [31] Conservation Coalition goes on to argue that Portfolio 6 would save hundreds of millions of dollars in capital costs for generation and transmission during the RAP relative to the Preferred Portfolio.[32] Conservation Coalition adds that Portfolio 6 has lower risks than the Preferred Portfolio, such as a lower risk of overbuilding capacity and lower risks associated with making future off-system sales. [33]

51. Conservation Coalition further notes that the Preferred Portfolio would emit 4.2 million tons more carbon dioxide emissions relative to alternative portfolios such as Portfolio 6. Conservation Coalition argues Tri-State should not pass up the opportunity to select Portfolio 6 to accomplish 4 million tons of additional carbon dioxide emissions reductions in the

[30] Wyoming Cooperatives Comments, p. 2.
[31] Conservation Coalition Comments, p. 2.
[32] Conservation Coalition Comments, p. 7.
[33] Conservation Coalition Comments, pp. 10-13.

2030s and 2040s for little to no incremental cost.[34] Conservation Coalition also argues that Colorado law already requires Tri-State to eliminate its carbon dioxide emissions by 2050 and it is virtually certain that Colorado will adopt interim carbon dioxide emissions reduction requirements for the years before 2050.[35]

52. With respect to reliability, Conservation Coalition argues that both the Preferred Portfolio and Portfolio 6 meet the Level 1 and 2 Reliability Metrics "with both having no unserved energy or zero loss of load probability; and both have nearly identical reserve margins. Thus, reliability is not a basis for rejecting Portfolio 6, as the portfolio meets all of the same reliability metrics as Portfolio 4."[36] Conservation Coalition likewise states, to the extent that Tri-State is concerned that it may need a new gas plant to come online in 2031, Tri-State has better options than bringing a plant online in 2029 that it does not need for capacity purposes in 2029 or 2030.[37]

53. Conservation Coalition further challenges Tri-State's concerns about a potential "overreliance" on storage. Conservation Coalition states: "Because Portfolio 6 would add battery projects over a 5-year period, it would enable Tri-State to gain experience with the earlier projects before adding the later projects. Tri-State offers no explanation as to why the experience it gains in 2026 and 2027 with the early battery projects would not allow it gain the knowledge it needs to then operate additional battery projects in 2028–2030." [38]

54. Conservation Coalition also notes that the Preferred Portfolio and Portfolio 6 have the same local economic benefits because the Phase I settlement guarantees significant community

[34] Conservation Coalition Comments, p. 13.
[35] Conservation Coalition Comments, p. 3.
[36] Conservation Coalition Comments, p. 3.
[37] Conservation Coalition Comments, p. 11.
[38] Conservation Coalition Comments, p. 18.

assistance payments by Tri-State regardless of which portfolio the Commission approves here in Phase II. Specifically, under any portfolio, Tri-State will pay $22 million to an economic development fund administered by Moffat County and the City of Craig, as well as payments for lost tax revenue to Moffat County and the City of Craig totaling $48 million from 2028 through 2038.[39]

55. Conservation Coalition further suggests there are serious questions of accuracy of Tri-State's Phase II modeling. Conservation Coalition states: "Tri-State has taken at face value the bidder specifications that the heat rate of the new gas plant would be significantly lower (*i.e.*, more efficient) than any publicly available heat rates for comparable combustion turbines… Rather than verify these questionable assumptions or seek contractual guarantees that the bidder will actually achieve these unusually low heat rates, Tri-State simply plugged these values into the model and returned results that are as unusual as the heat rates: having a peaking gas plant run at a 40% capacity factor for multiple years. For these reasons, the Commission should view Tri-State's economic modeling of the new proposed gas plant with deep skepticism."[40] Conservation Coalition also argues that the quantity of off-system sales from the new gas plant that Tri-State assumes is so large that changing that assumption would alter the relative economic ranking of the portfolios.[41] More generally, Conservation Coalition raises concerns surrounding the Encompass model, stating that the model is "not completing on its own" but is rather "stopping" due to exceeding maximum run-time limits (with every single portfolio and simulation step).[42]

[39] Conservation Coalition Comments, p. 20.
[40] Conservation Coalition Comments, p. 2.
[41] Conservation Coalition Comments, p. 11.
[42] Conservation Coalition Comments, p. 22.

**8. WRA**

56. WRA raises many of the same arguments as Conservation Coalition, objecting to the approval of Tri-State's Preferred Portfolio and supporting Portfolio 6 instead. WRA similarly asks that the Commission direct Tri-State to pursue Portfolio 6 instead of its Preferred Portfolio.[43]

57. WRA claims, for example, that Portfolio 6 has the lowest capital costs over the planning period, the lowest renewable curtailment costs, and the lowest PVRR when accounting for social cost of emissions, the last of which "accounts for the real-world costs of the emissions associated with utility resource acquisitions."[44] WRA also stresses that Portfolio 6 has the least curtailment across all of the presented portfolios.[45] Furthermore, WRA echoes the position of Conservation Coalition, stating that in selecting a cost-effective plan, the Commission should consider the real risk that new gas-fired generation resources may become stranded assets. WRA argues that deferring or avoiding the acquisition of new natural gas units can help to reduce customer stranded cost risk, lower emissions and costs, and allow for consideration of new clean, dispatchable technology bids in future solicitations.[46]

58. In terms of Level 1 Reliability Metrics, WRA notes the ERP Implementation Report indicates that Portfolio 6 is associated with zero loss of load hours and zero expected unserved energy during the modeling period. Further, the planning reserve margin for Portfolio 6 exceeds Tri-State's requirements as established in Phase I. According to WRA, Portfolio 6 outperforms the Preferred Portfolio according to Level 2 Reliability Metrics, because the Preferred Portfolio is

[43] WRA Comments, p. 5.
[44] WRA Comments, p. 7.
[45] WRA Comments, p. 11.
[46] WRA Comments, p. 13.

associated with one loss of load event under the extreme weather event analysis, whereas Portfolio 6 experienced no loss of load.[47]

59. WRA also asks the Commission to recognize that all of the portfolios presented in the ERP Implementation Report, including the Portfolio 6, are accompanied by the Just Transition commitments established in Phase I of this proceeding (*i.e.*, $70 million in payments, with $22 million paid over first four years into an economic development fund and $48 million paid over 11 years as property tax backstop payments, as well as a transfer of water rights).[48]

60. Turning to emission reductions, WRA asks that Tri-State provide, via its response comments, a quantitative and qualitative explanation for its projected system-wide and Colorado GHG emissions as well as Colorado GHG emissions through the entire planning period (ending in 2043), and a description of why the Company did not assess whether it was prudent to replace the Shafer turbines during Phase I.[49] For instance, WRA notes that the portfolios presented in the ERP Implementation Report only achieve an expected 80 percent emission reduction by 2030, as required by statute, but no further. According to WRA, this result contrasts with the Phase I modeling that indicated additional emission reductions were possible.[50] And with regard to Tri-State's modeling of Shafer, WRA states: "Tri-State's unilateral decision to construct the portfolios in this manner reflects a concerning lack of transparency in the Company's resource planning efforts. During Phase I, Tri-State did not indicate that it was considering replacement or repair of Shafer."[51] More generally, WRA asks the Commission to require Tri-State to present all Phase II portfolios on an analytically equivalent basis going forward.[52]

[47] WRA Comments, pp. 8-9.
[48] WRA Comments, pp. 13-14.
[49] WRA Comments, p. 4 and pp. 14-18.
[50] WRA Comments, Figures WRA-4 and 5, p. 15.
[51] WRA Comments, p. 20.
[52] WRA Comments, p. 21.

### 9. CIEA

61. CIEA primarily focuses on Tri-State's bid scoring process for this Phase II and concludes that its proposed reforms "are necessary to ensure a competitive and cost-effective resource acquisition process that serves the public interest."[53]

62. For example, CIEA contends that Tri-State was required to provide additional information on NPFs related to bid resources pursuant to Decision No. C23-0437, which required "[a]t minimum, [the 45-day report in Tri-State's next ERP] should include information on the number of bids that failed each screen, and the specific criteria within each screen that caused bids to fail… and assess whether any adjustments are advisable for future solicitations."[54] According to CIEA, Tri-State's 45-Day Report provided some of this information, but not in a meaningful way that was responsive to the Commission's concern. CIEA goes on to explain that neither the 45-Day Report nor the ERP Implementation Report provided sufficient detail as to the bids that failed each individual NPF screen and that both reports failed to explain why individual bids were eliminated by its NPF evaluation which, apparently, eliminated the majority of the bid pool prior to computer modeling.[55] CIEA also faults Tri-State for not including a discussion of how project characteristics aligned with its color-coding process, which went from three colors to five colors, in either its Report, the IE Report, or the 45-Day Report.

63. CIEA states that NPF screening data should be released in a disaggregated form prior to Tri-State's next RFP so that bidders better understand how Tri-State evaluates bids across NPF criteria.[56] CIEA suggests that this information, if released would also become public under Rule 3605(h)(III).

[53] CIEA Comments, p. 10.
[54] CIEA Comments, pp. 3-4, citing Proceeding No. 20A-0528E, Decision No. C23-0437, p. 25.
[55] CIEA Comments, pp. 5-7.
[56] CIEA Comments, p. 8.

### 10. COSSA

64. In its comments, COSSA asks Tri-State to explain the impacts of the launch of SPP RTO West on its interconnection process, specifically for projects that are a part of the Phase II portfolios. COSSA further requests that Tri-State provide any other relevant details about how the process for projects requesting interconnection on the Tri-State system that are not a part of this ERP will change under SPP RTO West.[57]

### G. Phase II Public Comments

65. Several dozens of members of the retail cooperatives served by Tri-State filed individual comments objecting to the acquisition of new gas-fired resources while otherwise supporting Tri-State's plans to acquire renewables and storage. A petition filed by over 200 cooperative members was also submitted again favoring the acquisition of renewables and storage but objecting to the new gas plant.[58]

66. In addition, certain local government officials in Colorado communities served by Tri-State—including county commissioners, elected town officials, and local government employees—filed comments expressing support for the adoption of Portfolio 6, stating that it "maximizes clean energy acquisition and limits investment in new gas infrastructure for the sake of energy affordability and community resilience to climate change."[59]

67. The Craig Rural Fire Protection District filed comments in support of Tri-State's Preferred Portfolio.[60]

[57] COSSA Comments, p. 2.
[58] Tri-State 2023 ERP Petition (Against NG).
[59] Comments 33 Local Government Reps.
[60] Comments Craig Rural Fire Protection District.

68. The Mayor of Ridgeway, San Miguel County, and San Miguel Power Association support the development of geo-thermal resources. [61]

**H. Tri-State's Response to Party Comments**

69. Tri-State defends the selection of its Preferred Portfolio in its responsive comments filed on June 10, 2025. Tri-State states that its projected costs are $88 million lower when compared to the next-closest alternative, which addresses a critical economic need for Tri-State's members. Additionally, Tri-State maintains that the Preferred Portfolio supports Colorado employment, provides stable tax revenue for Moffat County, and achieves APCD-verified emission reductions consistent with state requirements.[62]

70. With respect to the advocacy of Conservation Coalition and WRA to require Portfolio 6 over the Preferred Portfolio, Tri-State emphasizes that dispatchable combustion turbine capacity bids and semi-dispatchable battery capacity are not "identical." For example, Tri-State explains that it did not reject Portfolio 6 simply because of the potential overreliance on batteries.[63] Tri-State claims that Portfolio 6 does not offer the resources needed in the Western part of the state for spinning reserves and without a reliable resource to fill that gap, the stability of the system could be compromised, leading to increased operational risks and higher overall costs. Tri-State further argues the current low Effective Load Carrying Capability ("ELCC") of 45 percent for 4-hour batteries after the addition of 400 MW of storage indicates a substantial risk given its more limited contributions to system reliability during times of peak demand. Tri-State adds: "In contrast, long-duration batteries could potentially address this risk if those technologies further advance, offering a higher ELCC and therefore greater assurance of their

[61] Comments Ridgeway Mayor, San Miguel County Geothermal Support, San Miguel Power Association - Geothermal.

[62] Tri-State Response Comments, p. 6

[63] Tri-State Response Comments, p. 14.

contribution to reliability, and if their costs also decrease. However, it is important to recognize that, at present, gas plants provide a far more dependable solution, with an ELCC of 95 percent."[64]

71. Tri-State further argues its Preferred Portfolio includes robust, dispatchable generation resources that support grid reliability, especially during peak demand periods or when renewable sources are insufficient. Tri-State stresses that: "Although battery integration is important for a balanced energy strategy, the immediate needs of the Western Colorado system, particularly in the transition away from coal, require the inclusion of reliable dispatchable resources like gas plants to ensure overall system reliability."[65] More generally, with respect to reliability metrics, Tri-State explains that although they are critical, they "do not assess the benefits of a balanced energy strategy, including factors such as the value of reserves for system balancing."[66] Tri-State goes on to argue that, considering the minimal amount of Expected Unserved Energy ("EUE") shown in the Preferred Portfolio, and the portfolio's sufficient unused thermal capacity, it is difficult to draw a definitive conclusion that Portfolio 6 is more reliable.[67]

72. Tri-State generally agrees with Conservation Coalition's calculation of projected planning reserve margins during the RAP, acknowledging that the reserve margin will increase in 2029 and 2030 and then decrease rapidly in 2031 when the Springerville unit comes offline. Tri-State explains, however, that the timing of the resource additions in the portfolios presented in the ERP Implementation Report is not driven by the optimization of reserve margins but instead reflects resource acquisitions intended to ensure sufficient capacity is online by the time the Springerville unit is retired.[68] In other words, Tri-State argues there was no modeling assumption

[64] Tri-State Response Comments, p. 16.
[65] Tri-State Response Comments, p. 15.
[66] Tri-State Response Comments, p. 15.
[67] Tri-State Response Comments, p. 16.
[68] Tri-State Response Comments, p. 16.

around excess capacity. Rather, shifts in capacity seen in all portfolios are due to the timing of contracted sales coming offline and resource capacity coming online based on the modeled Commercial Operation Dates provided by bidders.

73. Turning to WRA's criticisms of Tri-State's portfolio selection through the lens of emissions, Tri-State objects to WRA's characterization of the projected emission reductions as "stalled." Tri-State states that it remains on track to meet all applicable emissions reductions requirements.[69] Tri-State also addresses the factors contributing to differences in expected emission reductions between Phase I and Phase II.[70]

74. Tri-State further explains that it has taken a conservative approach in modeling the economics of a new gas unit in the ERP Phase II modeling by limiting the depreciable life to 20 years.[71] In comparison, a recent generation plant depreciation study calculated a life span of 46-54 years for Tri-State's existing combustion turbine plants based on a database of over 9,000 U.S. power plants.

75. With respect to Conservation Coalition's contention that the heat rate for the selected gas-fired plant in the Preferred Portfolio appears to be lower than the specifications for comparable gas turbines, Tri-State admits that it used the heat rate as supplied by the bidder to conduct its Phase II modeling.[72] Nevertheless, Tri-States argues that the selection of the gas plant within the Preferred Portfolio is driven primarily by the need for dispatchable capacity and that, even if the heat rate for the plant is increased, the potential result will only be a reduction in the annual capacity factor of the plant but the model would likely still select that same resource.[73]

[69] Tri-State Response Comments, p. 20.
[70] Tri-State Response Comments, pp. 20-21.
[71] Tri-State Response Comments, p. 37.
[72] Tri-State Response Comments, p. 24.
[73] Tri-State Response Comments, p. 24.

Tri-State further explains that regardless of the heat rate guaranteed under the contract for the associated bid, it is committed to operating its system in a manner to achieve the Colorado emission reduction targets.

76. Tri-State goes on to argue that Conservation Coalition's and WRA's preference for Portfolio 6 due to lower risks of overbuilding is "counterintuitive," because Portfolio 6 results in building 1,900 MWs compared to 1,657 MWs.[74] Additionally, Tri-State argues that Portfolio 6 relies significantly on 4-hour duration battery energy storage, which increases risk by decreasing resource diversity, increasing supply chain issues around storage resources, and thereby increasing the likelihood of failed bids requiring additional considerations of back-up bids. Tri-State also faults the selection of Portfolio 6 instead of the Preferred Portfolio, because Tri-State argues that it needs to gain more operational experience with batteries before significantly increasing its reliance on the storage inherent in Portfolio 6.[75]

77. With respect to CIEA's concern regarding the number of bids that were eliminated in Phase II, Tri-State notes that a higher proportion of bids were advanced to modeling here than in the previous 2020 ERP.[76] Tri-State also clarifies that all bid screens, for purposes of determining bids advanced to modeling, were completed prior to the submission of the 45-Day Report and there were no "additional" NPF screens prior to computer modeling as CIEA suggested. Tri-State also explains that its 45-Day Report fully complied with Decision No. C23-0437, the Phase II decision in Tri-State's first ERP, which required Tri-State to work with interested stakeholders to attempt to arrive at mutually agreeable and practical level of information that can be provided.

[74] Tri-State Response Comments, p. 15.
[75] Tri-State Response Comments, p. 24.
[76] Tri-State Response Comments, p. 8.

78. With respect to CIEA's suggestion that the Commission require Tri-State to provide to individual bidders the "color" of the NPF analysis in which each area of their bid was categorized and the reasons for that categorization, Tri-State argues it has already provided detailed information on how it conducts its NPF analysis in Phase I testimony, the Bid Policy, the RFPs, the 45-Day Report, and the ERP Implementation Report.[77]

79. Tri-State further argues that disclosure of NPF information is unnecessary because, as stated above, Tri-State has already expressed its willingness to meet individually with bidders to discuss how their projects were evaluated.[78] Tri-State has also committed to including a numeric framework for its NPF analysis and to providing a scoring sheet as part of its direct filing in Phase I of its 2027 ERP, as provided in the 2023 Phase I Settlement Agreement.

**I. Tri-State's CPCN Motion**

80. On April 15, 2025, Tri-State filed the CPCN Motion. Tri-State requests that the Commission waive the requirement to file separate applications for Certificates of Public Convenience and Necessity ("CPCN") for two categories of actions: (1) the potential construction of a gas-fired generation resource that may be selected in Phase II; and (2) the retirement of the units at Craig. The Motion asserts that both issues are, or will, be fully addressed within this Proceeding and that duplicative filings would be inefficient and unnecessary.[79]

81. Tri-State notes that because it is not rate-regulated by the Commission, cost recovery considerations central to CPCN applications for investor-owned utilities are inapplicable here.[80] Accordingly, the primary regulatory objectives typically served by CPCN applications,

[77] Tri-State Response Comments, p. 11.
[78] Tri-State Response Comments, p. 13.
[79] CPCN Motion, pp. 11 and 16.
[80] CPCN Motion, p. 17.

such as prudence reviews, cost allocation, and rate impact analysis, are not applicable.[81] The Motion emphasizes that the Commission's oversight in this proceeding is grounded in ensuring that Tri-State's resource planning complies with the public interest and applicable law, which will be satisfied through the ERP process itself.

82. Tri-State also requests that the Commission waive subsections (b), (e), and (f) of Rule 3102 to the extent those provisions would otherwise require the resubmission of information, such as detailed project specifications and BVEM information, that will already be addressed in the Phase II filings in this Proceeding.[82] In support, Tri-State highlights the overlap between the requirements in Rule 3102(f) and those found in Rule 3605(h)(II)(C), which governs the treatment of BVEM information in Phase II bid evaluation.[83]

## J. Motion to Enforce Settlement, Strike Comments, and Require New Modeling

### 1. Conservation Coalition's and WRA's Joint Motion

83. On June 18, 2025, Conservation Coalition and WRA ("Joint Movants") jointly filed the CC/WRA Motion. The Joint Movants allege that Tri-State violated terms of the Phase I Settlement Agreement, particularly in the assessment within Tri-State's response comments of the reliability attributes of the resource portfolios presented in the ERP Implementation Report.

84. The CC/WRA Motion asserts that: "The Commission cannot approve Tri-State's preferred portfolio when Tri-State itself acknowledges that its modeling of the preferred portfolio rests on an incorrect value for a key input."[84] They suggest that the Commission take two actions: (1) strike, and give no weight to, Tri-State's statements on pages 12–13 of its response comments stating that a portfolio is reliable only if it includes a new gas plant in western Colorado; and

[81] CPCN Motion, pp. 1, 9, 11, and 17.
[82] CPCN Motion, p. 12.
[83] CPCN Motion, p. 15.
[84] CC/WRA Motion, p.3.

(2) either require Tri-State to re-run the modeling of the Preferred Portfolio with the correct inputs for the gas plant and provide a summary of changes to the results for the portfolio including resource build decisions, system cost, emissions, and utilization of the new gas plant, or refuse to approve any portfolio that includes the gas plant, which was modeled with an incorrect input.

**2. Tri-State's Response**

85. Tri-State filed a response objecting to the relief sought in the CC/WRA Motion. Tri-State argues that the motion is an improper attempt to reply to Tri-State's response comments, a procedural step not contemplated in the Commission's ERP Rules. Tri-State further argues that, because time is of the essence for the Commission to issue its Phase II decision, granting certain of the relief sought in the CC/WRA motion, such as additional modeling, will prolong the process and "could expose Tri-State and its Members to higher prices or lost opportunities as developers adjust to tariffs or new legislation, and could delay resources being included in a Resource Solicitation Cluster ("RSC") for interconnection study... on the basis of speculative concerns that are unlikely to result in material changes to the record currently before the Commission."[85] Tri-State asserts that it complied with § 4.8.2 of the Settlement Agreement by ensuring that all portfolios were modeled to meet Level I and II reliability metrics. Tri-State further contends that: "Nothing in the Settlement Agreement or the Commission's rules supports excising Tri-State's statements simply because the Conservation Parties disagree with them."[86] Tri-State argues that: "Running the model again might change the projected net present value of Portfolio 4 or its emissions by a modest amount, but it would not likely lead to a different portfolio being superior. On the other hand, the harm of delay is tangible: potential higher costs to Tri-State's Members and

[85] Tri-State Response CC/WRA Motion, p. 3.
[86] Tri-State Response CC/WRA Motion, p. 7.

potential failure to meet planned in-service dates if procurement and interconnection is stalled. The public interest favors moving forward with a decision based on the best available information now, rather than perfection of information later."[87]

### 3. COSSA/SEIA Response

86. COSSA/SEIA do not take a position on the request to strike Tri-State's Phase II comments, but they oppose any re-modeling of the Preferred Portfolio 4, citing the urgent need to approve clean energy resources while current federal tax incentives are still available. They likewise warn that re-modeling would introduce delays that could result in lost funding opportunities.

87. COSSA/SEIA go on to emphasize that any delay in approving Tri-State's resource acquisitions could threaten the feasibility and affordability of its clean energy transition, especially given the time-sensitive nature of the New ERA grants. They also argue that Tri-State's Phase II process must be evaluated considering this broader policy context and pressing financial deadlines, even if the process was potentially imperfect.

88. COSSA/SEIA urges the Commission to immediately approve all renewable energy projects common to both the Preferred Portfolio and Portfolio 6 in the event that the Commission grants the CC/WRA Motion. They explain that this approach would allow Tri-State to move forward with acquiring those projects while the modeling dispute is resolved. They also propose that if the Commission finds the record inadequate to support the Preferred Portfolio, Portfolio 6 should be approved as a fallback, recognizing that this path, too, carries litigation and delay risks.

[87] Tri-State Response to CC/WRA Motion, p. 22.

89. Finally, COSSA/SEIA requests that the Commission require Tri-State to provide regular updates on its PPA negotiations, modeled on reporting requirements from Proceeding No. 21A-0141E. They suggest monthly updates showing project status, executed contracts, and any fallback bids being considered, to help ensure timely acquisition and minimize risk.

**K. Discussion, Findings, and Conclusions**

**1. Cost Effective Resource Plan**

90. We approve Tri-State's selection of the Preferred Portfolio as the cost-effective resource plan even though there are elements of Portfolio 4, we do not prefer when compared to Portfolio 6. The Commission's role in Phase II of this ERP is to ensure that Tri-State respects the stakeholders in this process, considers and responds to their requests, and presents a preferred plan that is reasonably supported by the evidence in the record. The Commission should not substitute its judgement for Tri-State's when the selection of its preferred plan could be deemed reasonable and an alternative could also be deemed reasonable based on the same record. The corollary to that orientation is that Tri-State takes responsibility for the risks it and its cooperative members assume by pursuing its preferred plan.

91. We are persuaded that the Preferred Portfolio is an economic selection based on the presentation Tri-State makes in the ERP Implementation Report. This is a nuanced conclusion, however, because the Phase II record is not as "clear" as Tri-State concludes in its ERP Implementation Report. While the Preferred Portfolio is shown by Tri-State's modeling to potentially be cheaper than Portfolio 6 by some financial measures, it is also shown to be more expensive when applying the social cost of carbon and could be more expensive when considering the cost risks in possible future scenarios for curtailments or emission reduction requirements

beyond 2030. Nevertheless, based on the record, we can reasonably conclude that, in terms of economics, the Preferred Portfolio and Portfolio 6 are likely equivalent.

92. The siting of the natural gas plant in Moffat County will help to bring development and tax base to the community in the face of the retirement of the units at Craig. We further acknowledge that the project is supported by a broad range of parties including the local communities. The City of Craig and Moffat County have filed support for the gas plant citing concerns about ongoing tax revenue.

93. We highlight the level of renewables in both the Preferred Plan and Portfolio 6, and, consistent with the parties' comments and Tri-State's response, we encourage Tri-State to secure those projects expeditiously. Critically, the record also shows that both the Preferred Portfolio and Portfolio 6 comply with Colorado's emission reduction targets.

94. We also highlight Tri-State's commitment to acquiring more than 650 MW of battery storage, which most of the parties' support and we conclude is reasonable. While we can understand Tri-State's interest in resource diversity through the inclusion of the gas plant in Moffat County, primarily because Tri-State persuades us that there are ancillary benefits from the operation of the proposed plant in Western Colorado, we are not convinced that a legitimate barrier to acquiring the additional storage in Portfolio 6 is Tri-State's lack of experience with operating such resources. Tri-State currently has so little experience with storage of such scale such that it is unclear whether there is any meaningful difference between the two portfolios in the development of storage over time, the point raised by the Conservation Coalition and WRA.

95. Notwithstanding our approval of the Preferred Plan, the record also reveals serious modeling challenges that have fostered doubts among certain parties. As discussed below, we intend to address those challenges, and other needed improvements to Tri-State's implementation

of ERPs, before Tri-State files its next ERP to achieve a clearer record on prudent economic planning in the future. We further reiterate the financial risks highlighted by certain parties in their comments on Tri-State's ERP Implementation Report and assume that Tri-State's board and cooperative members are aware of these risks as they relate to preferred Tri-State's resource selection.

96. We also remain concerned about Tri-State's policies that prevent its member cooperatives from investing themselves directly in energy storage to reduce their demand charges. Considering the positive demonstration of the role battery storage can service on its system, Tri-State would also benefit from changing its policy to allow their member cooperatives to manage their costs through additional strategic investments in energy storage, to lower system peaks, thereby lowering costs and reducing fuel price risk for its membership.

97. In sum, we find that Tri-State has adequately considered statutory requirements for §§ 40-2-123, 40-2-124, and 40-2-134, C.R.S., set forth in Rule 3605, including environmental and social factors and insulation from fuel price increases through the focused competitive bid process and the selection of a renewable resource. The Preferred Portfolio supports the energy policy goals of Colorado in putting Tri-State on the path to achieve 80 percent reduction of GHG emissions by 2030.

**2. Best Value Employment Metrics**

98. Rule 3605(h)(II)(C) states that the Commission's Phase II decision shall determine, in accordance with § 40-2-129, C.R.S., whether the utility has obtained and provided BVEM information and has taken certain other steps. BVEM information includes the availability of training programs such as apprenticeships; the employment of in-state instead of out-of-state labor; long-term career opportunities; and industry-standard wages, health care, and pension benefits.

As in is previous ERP, Tri-State's bid evaluation process applied BVEM information as a qualitative NPF within Community Stewardship.[88]

99. No comments were filed suggesting deficiencies in the BVEM data that was provided by bidders.

100. Upon review of the materials and the bid process, particularly Attachment F to the ERP Implementation Report, we find that Tri-State has complied with Rule 3605(h)(II)(C), and in accordance with § 40-2-129, C.R.S., Tri-State has provided the requisite BVEM information and has demonstrated objective standards for how it evaluated BVEM as between bids.

### 3. Motion for CPCN Waivers

101. No responses to Tri-State's CPCN Motion were filed. Tri-State's CPCN Motion is therefore deemed to be unopposed.[89]

102. On May 22, 2025, through Decision No. R25-0393-I ("Interim Decision"), ALJ Segev granted the CPCN Motion. Regarding the retirement of the units at Craig, the Interim Decision concludes that good cause exists to waive the requirements of Rule 3103(a). The ALJ states that the Commission approved the retirement of Craig unit 1 in its Phase I decision, concluding that it is consistent with the public interest and supported by the Settlement. The ALJ states that no further public convenience and necessity determination is required under Rule 3103, as the record in this proceeding has already fully addressed the timing, justification, and implications of the retirement. Accordingly, "A separate CPCN application would serve no additional regulatory purpose and would unnecessarily duplicate prior findings."[90]

[88] Tri-State ERP Implementation Report, pp. 9 and 13.
[89] CPCN Motion, p. 2.
[90] Interim Decision, ¶ 26, p. 10.

103. By this Decision, we uphold the ALJ's findings and conclusions with respect to the retirement of the units at Craig. We therefore incorporate the findings entered in the Interim Decision with respect to the units at Craig. No separate CPCN filing is necessary to support the retirement of the units at Craig.

104. Regarding the gas plant in Moffat County within the Preferred Plan, the Interim Decision finds that because the Phase II ERP process will include a robust evaluation of the need, alternatives, costs, timelines, and employment metrics associated with the resource addition, rendering a separate CPCN proceeding would be duplicative and inefficient. The Interim Decision states: "a CPCN application may be waived when the proposed facility is subject to thorough evaluation and public review in a Commission approved ERP." [91] The Interim Decision also concludes that no prudence or cost-recovery determinations are implicated due to Tri-State's exempt status under § 40-9.5-103, C.R.S.

105. We also agree with the ALJ on this point and incorporate the findings entered in the Interim Decision with respect to the new gas plant. No separate CPCN filing is necessary to support the construction and operation of the facility by Tri-State.

### 4. Phase II Motion of Conservation Coalition and WRA

106. We deny the requests in the CC/WRA Motion for additional modeling and reject the suggestion that the Commission refrain from approving any portfolio that includes the gas plant included in the Preferred Plan because we instead conclude that the record in this Proceeding supports the adoption of Tri-State's Preferred Portfolio as a cost-effective resource plan.

107. Turning to the request to strike certain portions of Tri-State's responsive comments, we acknowledge the importance of ensuring that all parties adhere to the commitments in a

[91] Interim Decision, ¶ 24, p. 9.

Settlement Agreement. However, in this Phase II, the record reflects that Tri-State applied Level 1 and Level 2 reliability metrics to all six portfolios presented in the ERP Implementation Report, and that all of them passed those screens. No party disputes that point. The Settlement Agreement also provides that the parties in Phase II, including Tri-State, retain the right to take any position on the modeling. Notably, the Settlement Agreement does not constrain what those arguments can be, so long as the portfolios presented in the ERP Implementation Report meet the agreed reliability thresholds.

108. Here, the Joint Movants express concern that Tri-State's responsive comments create an impression that only the Preferred Portfolio is “reliable.” However, it is necessary to distinguish between modeling and compliance with the Settlement Agreement and the advocacy of any party. The Settlement Agreement required uniform modeling which Tri-State provided. The Settlement Agreement did not bind parties to silence on the issues of operational judgment or grid conditions in Phase 2.

109. We conclude that there is no evidence of the type of misrepresentations that would warrant the striking of portions of Tri-State’s responsive comments in Phase II or evidence that Tri-state failed to comply with the framework of the Settlement Agreement approved in Phase I. Selectively excluding portions of one party's advocacy, particularly when the Settlement Agreement explicitly preserves the right of any party to present such positions, would raise concerns about fairness and consistency.

110. Accordingly, we deny the request to strike any of Tri-State’s responsive comments and thus also deny the final element of the CC/WRA Motion. While we share COSSA/SEIA’s interest in Tri-State pursuing the renewable and storage projects in the Preferred Plan expeditiously, we deny their request that the Commission require Tri-State to provide regular

updates on its PPA negotiations. As explained above, it is incumbent upon Tri-State to implement its Preferred Plan to the benefit of its cooperative members.

### 5. Future Proceeding Prior to 2027 ERP

111. In Tri-State's last ERP proceeding, the Phase II decision addressed several requirements for Tri-State's next ERP.[92] The Phase I Settlement Agreement approved in this Proceeding also includes several provisions related to Tri-State's next ERP to be filed in 2027.[93]

112. In this Proceeding, CIEA, Staff, and others direct some or all of their comments on needed improvements to Tri-State's ERP practices, including improvements to modeling, disclosures and assessments of resource actions such as the replacement of the turbines at Shafer, and bid screening. As discussed above, the modeling challenges in this Phase II have raised concerns among certain parties and have complicated the establishment of a cost-effective resource plan. All these issues merit further consideration prior to Tri-State's next ERP.

113. However, we are also mindful of Tri-State's request for a Phase II Decision as soon as possible. Tri-State argues in its response to party comments that time is of the essence with respect to acquisition of any of the resources described in the ERP Implementation Report.[94] Tri-State points to the present volatility of the global market for renewable-energy equipment and recent U.S. tax and trade actions have introduced material pricing risks that Tri-State hopes to mitigate by promptly executing bid agreements.

114. In the interest of issuing this Phase II Decision as quickly as possible and due to the press of business before the Commission currently, we decline to render findings and directives related to the Tri-State's next ERP. Instead, because the next ERP will not be filed until late 2027,

[92] Decision No. C23-0437, issued June 30, 2023, Proceeding No. 20A-0528E.
[93] Phase I Settlement Agreement, pp. 15, 18, 19-20, 24-25.
[94] Tri-State Response Comments, pp. 4-5.

we conclude that it would be more efficient and appropriate to take up these issues in a separate future proceeding.

**6. Craig Units Not Needed for Reliability**

115. In their comments on the ERP Implementation Report, Conservation Coalition urges the Commission to make a factual finding in this Proceeding that Craig Unit 1 is not needed for reliability purposes after December 31, 2025. They argue that the Commission should make this finding because it is fully supported by the record and because the federal Department of Energy has threatened use of Section 202(c) of the Federal Power Act to force coal units to operate beyond their announced retirement dates.

116. We agree with Conservation Coalition Conservation Coalition 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 assumes that Craig Unit 1 retires at the end of 2025 and does not provide any energy or capacity after 2025. At the same time, Tri-State convincingly concludes that every portfolio meets all reliability metrics and is reliable.

**7. Waiver of Rule 3605(h)(II)(A)**

117. By its own motion, the Commission waives Rule 3605(h)(II)(A), which requires the Commission to issue a written decision on Phase II within 90 days after the receipt of the wholesale electric cooperative’s report. Additional time has been needed in this Proceeding given the Commission’s significant caseload at this time and the unanticipated complexity of the Phase II decision caused in large part by the modeling challenges discussed above.

# II. ORDER

## A. The Commission Orders That:

1. The Commission approves as a cost-effective resource plan the Preferred Portfolio presented by Tri-State Generation and Transmission Association ("Tri-State") in its 2023 Electric Resource Plan Phase II Implementation Report filed on April 11, 2025, in accordance with the Electric Resource Planning Rules set forth at 4 *Code of Colorado Regulations* 723-3-3600 *et seq*., and consistent with the discussion above.

2. The Motion for Partial Waiver of Rules 3102 and 3103 in Connection with a Gas Resource Addition and Craig Station Retirement filed by Tri-State on April 15, 2025, is granted, consistent with the discussion above.

3. The Motion to Enforce Settlement Agreement, Strike Comments, and Require New Modeling filed jointly by the National Resources Defense Council, Sierra Club, and Western Resource Advocated on June 18, 2025, is denied, consistent with the discussion above.

4. Rule 723-3-3605(h)(II)(A) is waived, consistent with the discussion above.

5. 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.

6. This Decision is effective upon its Issued Date.

**B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING August 1, 2025.**

(S E A L)

STATE OF COLORADO ★ THE PUBLIC UTILITIES COMMISSION ★ NIL SINE NUMINE

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit EE: PRPA, *2024 Integrated Resource Plan* (Apr. 2023)

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

# 2024 Integrated Resource Plan

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

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# Glossary

| Term or acronym | Definition |
|---|---|
| **ATB** | Annual Technology Book |
| **BE** | Beneficial building electrification |
| **CDPHE** | Colorado Department of Public Health and Environment |
| **CIG** | Colorado Interstate Gas |
| **CPI** | Consumer Price Index |
| **DER** | Distributed energy resources |
| **DG** | Distributed generation |
| **DR** | Demand response |
| **ELCC** | Effective Load Carrying Capability |
| **EPA** | U.S. Environmental Protection Agency |
| **EPRI** | Electric Power Research Institute |
| **ERCOT** | Electric Reliability Council of Texas |
| **EV** | Electric vehicle |
| **GW** | Gigawatt |
| **GWh** | Gigawatt-hour |
| **HVAC** | Heating, ventilation and air conditioning |
| **IRP** | Integrated resource plan or integrated resource planning process |
| **ITC** | Federal solar tax credit |
| **JDA** | Joint dispatch agreement |

**LOLE**............................ Loss of Load Expectation

**LOLH**............................ Loss of Load Hours

**MISO** ............................ Midcontinent Independent System Operator

**MW** ................................ Megawatt

**MWh**............................. Megawatt-hours

**NEM**.............................. Net energy metering

**NEVI** ............................. National Electric Vehicle Infrastructure Formula Program, a federal grant program established under the Infrastructure Investment and Jobs act to provide states with funding to expand availability of EV fast charging infrastructure on transportation corridors

**NREL** ........................... National Renewable Energy Laboratory

**ODTY** ........................... One Day in Ten Years

**PPA** ............................... Power purchase agreement

**PRM**.............................. Planning reserve margin

**RDP** .............................. Resource Diversification Policy

**RFP** ............................... Request for proposals

**RP22**............................. Platte River's Resource Plan 2022

**RTO West**.................... Regional Transmission Organization West

**SPP** ............................... Southwest Power Pool

**TOU** .............................. Time of use

**VPP**............................... Virtual power plant

**WAPA** ........................... Western Area Power Administration

**WECC**........................... Western Electricity Coordination Council

**WEIS**............................. Western Energy Imbalance Service market

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# 01 Executive summary

Platte River Power Authority's 2024 Integrated Resource Plan (IRP) presents a comprehensive strategy to reduce carbon emissions for the communities we serve in Northern Colorado while upholding our foundational pillars of reliability, financial sustainability and environmental responsibility. Developed amidst unprecedented market changes, the IRP addresses the challenges of long-range planning by evaluating various decarbonization scenarios and incorporating feedback from our board of directors, customers and stakeholders.

The IRP explores a diverse range of resource options for continuing our work toward the Resource Diversification Policy (RDP) goal, including renewable energy, battery energy storage, distributed generation, energy efficiency and demand response. The plan also shows how we will maintain reliability with an energy portfolio composed primarily of weather-dependent, renewable resources.

Given the inherent uncertainties in long-term planning, the IRP is based on projections of future electricity demand, costs of renewable resources, advancements in technology, and evolving market and regulatory environments. Acknowledging that these factors will change, the plan is intended to serve as a roadmap, allowing for adjustments and modifications to optimally reflect changing market conditions and continue the implementation of our decarbonization strategy.

This IRP informs Platte River's next steps toward achieving a low-carbon energy portfolio by illustrating how we will reduce carbon emissions by at least 80% below 2005 levels by 2030 to meet state goals, and by supporting our board-adopted RDP.

## Outreach and engagement

Building on what we learned from the last IRP, we expanded our outreach and engagement efforts considerably for the 2024 IRP.

We partnered with our owner communities to help educate customers about the relationship between Platte River and their cities. Over a six-month period, we presented our IRP process and updates to numerous community organizations, stakeholder groups and city leadership. We coupled these presentations with two engagement sessions hosted by Platte River to share IRP milestones, and offered digital resources including a dedicated website, email address and robust database of frequently asked questions and answers.

The feedback we collected between June and November 2023 helped inform the development of the portfolios.

## Portfolios

The IRP is designed to align Platte River's future portfolio with our continued work toward the RDP, with a primary focus on reducing carbon while maintaining reliability. All portfolios will emit some carbon in 2030 because commercially viable noncarbon dispatchable options are not available. After 2030, we model no new thermal generation and plan for long-duration energy storage. Energy prices assumed embedded carbon taxes in the evaluation of each portfolio.

**No new carbon:** Focuses on wind, solar and energy storage, testing the viability of excluding new thermal generation to meet demand and reliability.

**Minimal new carbon:** Adds a modest amount of new thermal generation (80 megawatts) to support reliability and evaluates potential emerging technologies.

**Carbon-imposed cost:** Adds a carbon cost to discourage new carbon-emitting resource additions to the resource mix.

**Optimal new carbon:** Balances cost, reliability and carbon considerations between the additional new carbon and carbon-imposed cost portfolios.

**Additional new carbon:** Presents a least-cost portfolio without specific carbon constraints, prioritizing cost and reliability.

Because external risks to executing the clean energy transition have substantially increased, Platte River developed a risk-adjusted plan to address the challenges of integrating renewable resources as modeled. The primary risks are supply chain issues; engineering, procurement and construction delays; regulatory uncertainty on pricing; the mismatch in timing between customer demand and the availability of renewable generation; and market price volatility. This plan also allows for adjustments to market prices, emerging technologies and regulatory developments.

# Conclusion

We are pleased to present the third iteration of the resource plan since our board passed the RDP. While we have made significant progress diversifying our portfolio since 2018—adding renewable energy to serve about one third of the owner communities' energy needs on an annual basis—we will immediately begin work on the fourth iteration as factors continue to change and evolve around us.

As you review our latest plan, we hope you take away a greater understanding of the complexity and challenges of replacing coal with renewables, firming up the intermittency of renewables with dispatchable resources, and doing right by the owner communities and our employees while pursuing one of the most accelerated decarbonization goals in the country.

This clean energy transition is a journey that will continuously evolve with changing circumstances and advancements in technology. Platte River is committed to making the transition on behalf of the owner communities to create a diverse, low-carbon energy portfolio for a sustainable future.

# 02
# Introduction

Platte River Power Authority's 2024 IRP is a living document that guides and informs our efforts to supply reliable, environmentally responsible and financially sustainable energy and services to our owner communities while we work toward a noncarbon energy future. Throughout this document, we highlight how Platte River will address high-level policy goals while incorporating staff recommendations and research, third-party studies, and legislative, regulatory, market and technology changes.

Platte River developed this IRP with involvement from our owner communities and their customers. The board of directors approved the previous IRP document in 2020. Platte River is required to update the IRP and file it with the Western Area Power Administration (WAPA) every five years.

The report is organized as follows:

- The remainder of this section provides a general overview, background and history of Platte River, illustrating the foundational pillars and board-adopted policy that guide our planning activities and decisions.
- While IRPs are common among electric utilities, Platte River's approach is unique. Chapter 3 describes our process and timeline, the progress we made since our last IRP, and the industry challenges we face, including persistent impacts from the COVID-19 pandemic. Chapter 4 further highlights the variables and challenges Platte River faces as we pursue a clean, reliable energy future.
- Most of the report provides technical background data, assumptions and methodology that influence and shape our IRP, including demand, impacts of distributed energy resources (DER) and electrification, supply-side assumptions, extreme weather events and more. Chapter 7 of this report details the IRP design, including the studies, portfolios and our modeling methodology.
- Chapter 8 shows our modeling results; Chapter 9 highlights the resulting action plan from this IRP.

# Public power utilities

Platte River is one of more than 2,000 community-owned electric utilities in the U.S. These utilities are operated by local governments and provide their owner communities with reliable, responsive, not-for-profit electric service. Public power utilities serve one in seven electricity customers across the U.S. – more than 54 million citizens – and operate in 49 states and in several U.S. territories.[1]

The American Public Power Association emphasizes the following characteristics of public power utilities:

- **Service-oriented:** We exist to serve and add value to our owner communities.
- **Community-owned:** We help advance the good of the community.
- **Local control and decision-making:** Decisions reflect our owner communities' needs and values.
- **Not-for-profit:** We focus on safely providing reliable, environmentally responsible and financially sustainable energy and services.
- **Responsive:** Because we are part of our communities, we react quickly to their needs.

[1] American Public Power Association website, www.publicpower.org


## 2.1 Platte River overview

Until the mid-1960s, many Colorado municipal utilities separately received wholesale electric service from the Bureau of Reclamation's system of hydroelectric generating facilities throughout the Colorado and Missouri River basins. In late 1965, 31 municipal utilities created the Platte River Municipal Power Association to manage and protect their collective hydropower rights, particularly due to the Bureau's announcement that it could not meet growing energy needs beyond the mid-1970s and no new (hydroelectric) energy projects would be built.

In 1973, four of the original 31 municipal utilities—Estes Park, Fort Collins, Longmont and Loveland—collaborated to pass legislation to form the Platte River Power Authority, a not-for-profit entity that would provide its owner communities with long-term energy above their limited allotment of federal hydropower. Following voter approval of a constitutional amendment, Platte River reformed in 1975 as a joint action agency, empowered to acquire assets to better serve its owner communities. These assets are discussed in greater detail throughout this document.

Also in 1975 (after the Colorado legislature passed enabling legislation), the four communities signed the organic contract establishing Platte River as a political subdivision of the state of Colorado. The organic contract is the agreement between the four owner communities that creates Platte River, establishing its purpose and governance structure.

Platte River is governed by an eight-person board of directors. The board includes the mayor (or a designee of the mayor) of each owner community and four other directors who are appointed to four-year staggered terms by the governing bodies of the owner communities. The board meets nine times per calendar year to establish and guide policy for the organization.

## 2.1.1 Foundational pillars

Platte River is guided by three pillars that drive its mission. Together with our vision and values, these pillars inform all activities and serve as the foundation for Platte River's decarbonization efforts.

### Reliability

Providing a highly reliable supply of power to our owner communities

### Environmental responsibility

Achieving noncarbon energy goals and protecting our natural resources

### Financial sustainability

Managing financial risks, providing stable, competitive wholesale rates that generate adequate cash flow and maintain access to low-cost capital

## 2.1.2 Vision, mission and values

### Our vision

To be a respected leader and responsible power provider improving the region's quality of life through a more efficient and sustainable energy future.

### Our mission

While driving utility innovation, Platte River will safely provide reliable, environmentally responsible and financially sustainable energy and services to the owner communities of Estes Park, Fort Collins, Longmont and Loveland.

## Our values

**Safety:** Without compromise, we will safeguard the public, our employees, contractors and assets we manage while fulfilling our mission.

**Integrity:** We will conduct business equitably, transparently and ethically while complying fully with all regulatory requirements.

**Service:** As a respected leader and responsible energy partner, we will empower our employees to provide energy and superior services to our owner communities.

**Respect:** We will embrace diversity and a culture of inclusion among employees, stakeholders and the public.

**Operational excellence:** We will strive for continuous improvement and superior performance in all we do.

**Sustainability:** We will help our owner communities thrive while working to protect the environment we all share.

**Innovation:** We will proactively deliver creative solutions to generate best-in-class products, services and practices.

# Environmental leadership

Platte River continually demonstrates a strong commitment to environmental responsibility while safely providing reliable and financially sustainable energy and services to the four owner communities. Below are examples of our environmental stewardship:

- Incorporated state-of-the-art emissions controls on the coal-fired Rawhide Unit 1, consistently positioned among the lowest SO2-emitting coal-fired plants in the country, according to data available from the U.S. Environmental Protection Agency (EPA).
- Became the first utility in Colorado to offer wind energy to the owner communities through the Medicine Bow Wind Project in 1998.
- Began commercial operation of 30 MW of solar at the Rawhide Energy Station in 2016. Platte River later added another 22 MW of solar to the area, with a 2 megawatt-hour (MWh) battery storage facility.
- Completed construction of a new headquarters campus in Fort Collins in 2020 that is designed to serve as an example of energy efficiency. The campus received Gold LEED Certification by the U.S. Green Building Council in 2023.
- Adopted the Resource Diversification Policy in 2018, becoming one of the first utilities in Colorado and the country to set a goal of a 100% noncarbon energy mix by 2030.

## 2.2 Resource Diversification Policy

In 2018, Platte River's Board of Directors passed a landmark policy (Figure 1) that directs the general manager/CEO to proactively work toward the goal of reaching a 100% noncarbon energy resource mix by 2030 while maintaining the foundational pillars. The policy also lists several advancements (or caveats) that must occur for Platte River to meet this ambitious goal.

### Purpose

This policy is established to provide guidance for resource planning, portfolio diversification and carbon reduction.

### Policy

The board of directors (the board) directs the general manager/CEO to proactively work toward the goal of reaching a 100% noncarbon resource mix by 2030, while maintaining Platte River's three pillars of providing reliable, environmentally responsible and financially sustainable electricity and services.

The board recognizes the following advancements must occur in the near term to achieve the 2030 goal and to successfully maintain Platte River's three pillars:

- An organized regional market must exist with Platte River as an active participant
- Battery storage performance must mature and the costs must decline
- Utilization of storage solutions to include thermal, heat, water and end user available storage
- Transmission and distribution infrastructure investment must be increased
- Transmission and distribution delivery systems must be more fully integrated
- Improved distributed generation resource performance

- Technology and capabilities of grid management systems must advance and improve
- Advanced capabilities and use of active end user management systems
- Generation, transmission and distribution rate structures must facilitate systems integration

Resource planning is an ongoing process and Platte River continuously evaluates opportunities to add noncarbon resources. Platte River reviews its generation portfolio annually as part of the budgeting and planning process. This process sets the foundation for developing an IRP submitted to the Western Area Power Administration every five years as required. The resource planning process includes evaluating the progress of energy storage, distributed power sources and new technologies. As a leader in the utility industry in Colorado for many years, Platte River will continue to move forward to meet the resource needs and wants of the four owner communities. The board recognizes the integration of noncarbon resources and new technologies will shape the future of Platte River's and the four owner communities' energy supply.

**Figure 1.** *Resource Diversification Policy*

# 03 IRP process overview

## 3.1 What is an IRP?

A utility IRP[2] compares the supply-side resources (generated or purchased by the utility) and demand-side resources (contributed by customers, including DER) with projected energy needs (load) and selects an optimal set of resources to meet future needs while meeting the regulatory requirements and policy goals at the highest level of reliability.

Key components of an IRP include:

- Customers' future electricity needs (or load forecast)
- Future costs and availability of supply and demand side resources
- Regulatory and policy requirements including environmental considerations
- Community engagement to hear stakeholder feedback and questions
- An assessment of future technologies

These components and other inputs are used in a complex planning and optimization model to develop a 10-to-20-year roadmap of investments to provide reliable supplies during the planning horizon. An IRP model optimally selects from demand- and supply-side resources while meeting the planning reserve margin (PRM[3]) or other reliability criteria, to ensure adequate electricity supply under all reasonably expected variations of weather, customer demand and resource availability.

A key component of an IRP is an action plan that outlines the specific activities the utility plans to conduct in the next three to five years while developing the next IRP. An IRP is a snapshot in time; planning is an ongoing and dynamic process. An IRP acts as a roadmap or guide, while the actual investment decisions are made based on the best information available at the time of the decision.

[2] In this document the acronym IRP is used in two different ways–an integrated resource plan and as an integrated resource planning process

[3] PRM is defined as the additional generating capacity available to meet a future year peak demand. It is expressed as a percentage of peak demand. Historically, Platte River has maintained a 15% PRM which means if the load forecast expects a peak demand of 100 MW in a future year, Platte River would build or acquire 115 MW of generation or DER capacity to reliably meet that peak demand.

## 3.2 Why do an IRP now?

In 2020, Platte River developed an IRP that outlined several paths to work toward the RDP goal. The plan's recommendations were developed before the global COVID-19 pandemic, which put many things on hold for two years, including construction of renewable energy projects. The pandemic triggered widespread supply chain issues and contributed to increased costs for labor, capital, equipment and new resources, which resulted in multiple rounds of contract renegotiations for renewable projects. State and federal clean energy policies also created intense competition for renewable resource projects and related equipment and staffing.

Meanwhile, Winter Storm Uri in February 2021 was a wakeup call about the increased frequency of extreme weather events and the need for a reliable power supply. While the emergence of new technologies and the passage of the Inflation Reduction Act are positive developments, the industry continues to face inflationary pressures and supply chain challenges.

This 2024 IRP captures these developments, re-affirms our commitment to the RDP and charts a path toward that goal. While Platte River is not required to file an IRP with WAPA before 2025, we expedited this IRP to support the accelerated integration of renewable resources. We finalized our assumptions underlying this IRP in summer 2023, so this IRP provides portfolios or snapshots of the future viewed from 2023. This IRP will need updating as technology and circumstances evolve. Platte River will prepare the next IRP in 2028.

### 3.2.1 IRP timeline

The 2024 IRP process started in 2022 by commissioning pre-IRP studies from external consultants and continued through early 2024. Figure 2 illustrates a high-level timeline and list of major activities. Community engagement is an important part of the IRP process and is highlighted in yellow.

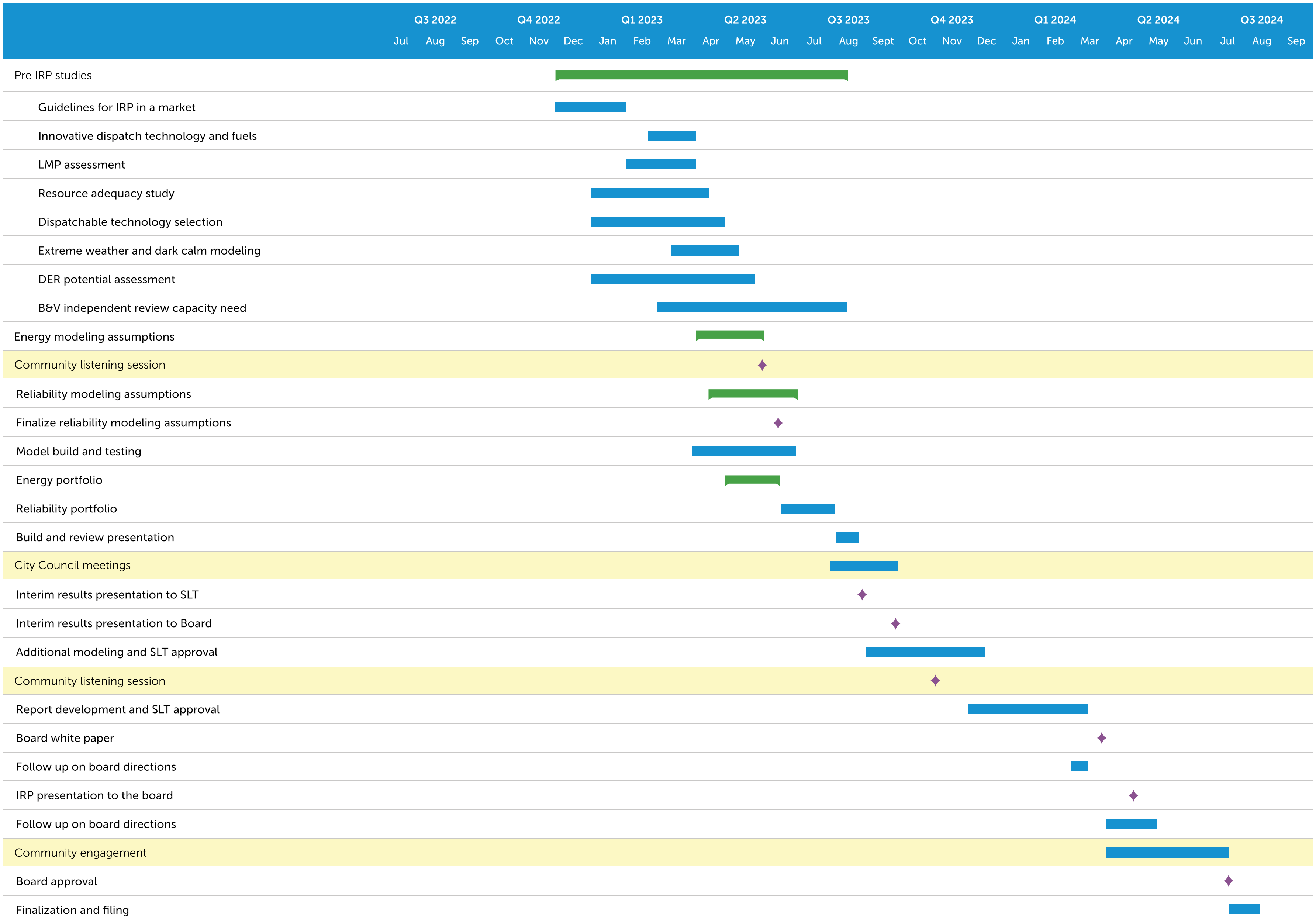



**Figure 2.** *Timeline of 2024 Integrated Resource Plan activities and milestones*

## 3.3 Progress since the last IRP

Platte River continued to work toward achieving the RDP after submitting our last IRP, acquiring more renewable generation, expanding efforts to join a regional market and working with the owner communities to expand DERs. Specific annual achievements are summarized below.

### 2020

- Began receiving energy from the Roundhouse Wind Energy Center, a 225-megawatt (MW), 80-turbine wind farm. Additionally, Platte River purchased the 230-kilovolt generator outlet line from the project, securing energy delivery to the owner communities throughout the 22-year power purchase agreement (PPA).
- Launched the DER strategy committee with staff members from Platte River and the owner communities. The DER strategy committee explores how to integrate systems that will better balance supply and demand as we transition our energy portfolio.
- Finalized closure dates for remaining coal units in Platte River's portfolio. Rawhide Unit 1 will close by the end of 2029, 16 years before its planned retirement. Craig Unit 2 will close by September 2028. (The 2025 closure date for Craig Unit 1 was announced in 2016.)
- Signed a PPA to build Platte River's largest solar project, which, when operational, will provide up to 150 MW of power.

### 2021

- Commissioned the 22 MW Rawhide Prairie Solar project, including a 2 megawatt-hour battery.
- Created the transition and integration division, combining DER and energy solutions with resource planning and information and operations technology departments to foster the innovation needed to achieve a noncarbon electric system that includes integrated DERs.
- Together with the owner communities, developed a comprehensive DER strategy providing a path forward to jointly attain the full value of DERs to the benefit of customers and the grid.
- The Efficiency Works Business team launched the Community Efficiency Grant to provide additional financial support for energy upgrades in businesses and multifamily properties serving the income-qualified community.
- Issued a request for proposals (RFP) to competitively procure up to 250 MW of solar generation and co-located battery resources connected at the distribution or transmission level.

## 2022

- Accelerated the timeline for new noncarbon energy resources to maintain the reliability and financial sustainability of the resource portfolio ahead of retiring coal-fired generation resources.
- Confirmed the purchase of 150 MW of solar energy from the vendor for the Black Hollow Solar project, restating an agreement originally signed in 2020. Logistical challenges delayed the project, now scheduled to begin commercial operation in 2025.
- Analyzed and evaluated large-scale four-hour storage and longer duration energy storage and evaluated adding an additional wind project to Platte River's portfolio. Developed a revised portfolio (RP22) that added about 105 MW more capacity by 2030 than the 2020 IRP. RP22 called for 450 MW of solar, 300 MW of wind, 200 MW of four-hour storage and 166 MW dispatchable thermal generation.
- Together with the joint dispatch agreement (JDA) partners, Platte River announced plans to join the existing Western Energy Imbalance Service (WEIS) operated by the Southwest Power Pool (SPP). The WEIS replaces the JDA and allows Platte River to gain experience operating in a larger imbalance market. Investments began in 2022 to prepare for entry into the WEIS.
- Launched an interactive electric vehicle (EV) shopper guide website with information on currently available EVs, including cost, performance specifications and available incentives, as well as a calculator that allows visitors to compare the total cost of ownership of EVs in comparison with each other and compared with conventional vehicles.

## 2023

- Issued an RFP to competitively procure 150-250 MW of wind generation. Responses to the RFP were received in late 2023, with evaluation of the responses continuing in 2024.
- Began operating in the SPP WEIS market.
- Selected a vendor for battery storage facilities located in the owner communities. The projects' expected capacity will range from 20-25 MW, consisting of four-hour duration lithium-ion batteries.
- Expanded the EV website to offer EV Fleet Planning as a calculator tool for local fleet operators to develop plans to calculate the costs of fleet transitions.
- Enhanced program offerings through the partnership between Efficiency Works and Energy Outreach Colorado to actively engage with participants on more significant home upgrades including energy efficiency and building electrification, resulting in nearly $1 million of investments to support the income-qualified residential upgrades in Platte River's owner communities.
- Expanded Efficiency Works programs to include multiple building electrification measures, supporting 359 heat pump installations with over $1 million in incentives to help customers to overcome financial hurdles and investing nearly $10,000 training local contractors on building electrification.
- Actively supported over 100 income-qualified customers to upgrade their homes, with plans to support over 250 customers annually in future years.
- Signed a commitment agreement to join the SPP Regional Transmission Organization West (RTO West) on April 1, 2026.
- Committed to advancing EV infrastructure by launching one of the highest incentives in the state, of $5,000 per public charging port, to promote public charger hosting by local business and multifamily properties by offsetting some of the installation cost.

# 3.4 External developments since the 2020 IRP

## 3.4.1 Pandemic

The COVID-19 pandemic brought unprecedented challenges worldwide and the power sector was no exception. Immediately after the pandemic started, the economic slowdown resulted in electricity demand reduction and changing demand patterns. As economic activity slowly resumed, the electricity demand started coming back with residential demand increasing (compared to pre-

[4] https://www.iea.org/reports/renewable-energy-market-update-june-2023/executive-summary

pandemic levels) due to a significant increase in citizens working from home.

Supply chain slowdowns are among the pandemic's biggest impacts and are detailed in the next section. The pandemic also slowed down construction and new renewable project development due to reluctance of investors to commit capital amid market volatility and uncertainty about future energy demand.

As the world began adapting and recovering after the first few months of the pandemic, it prompted many governments to reevaluate energy policies and regulatory frameworks to address emerging challenges and support economic recovery efforts. The pandemic also highlighted the importance of resilient and sustainable energy systems. Significantly higher demand and sustained challenges with supply chains contributed to the cost of renewable resources and energy storage projects nearly doubling post pandemic.

### 3.4.2 Supply chain issues

Supply chains were impaired by factory shutdowns, component shortages, labor shortages and financial, economic, demand and policy uncertainty during the pandemic. While this slowed down the supply side of electricity, the demand side recovered quickly and in fact, significantly increased. Renewable energy project supply chains are global and reflect worldwide demand. According to the International Energy Agency, the world added less than 200 gigawatts (GW) of new renewable resources in 2019 and more than 440 GW in 2023.[4] Although renewable supply chains are recovering from pandemic-related stress, the surge in demand is increasing pressure. In the U.S., the Inflation Reduction Act has significantly increased incentives to expand the domestic supply chain of renewable generation. But this further strains the supply chain as companies rush to develop U.S. renewable manufacturing.

This supply chain pressure directly impacts Platte River's resource procurement. For example, Platte River conducted an RFP in 2019 to add 100-200 MW of new solar capacity by 2023. The winning project, a 150-MW solar farm called Black Hollow Solar, is now expected to start commercial operation in 2025. Similar risks exist for projects planned for 2026 and 2027.

## 3.4.3 Renewable resource pricing

Due to supply chain issues and increased demand, the prices for renewables have significantly increased since the last IRP. As shown in Figure 3 from Level Ten Energy[5], PPA prices in the U.S. doubled by the end of 2023 compared to 2020 levels.

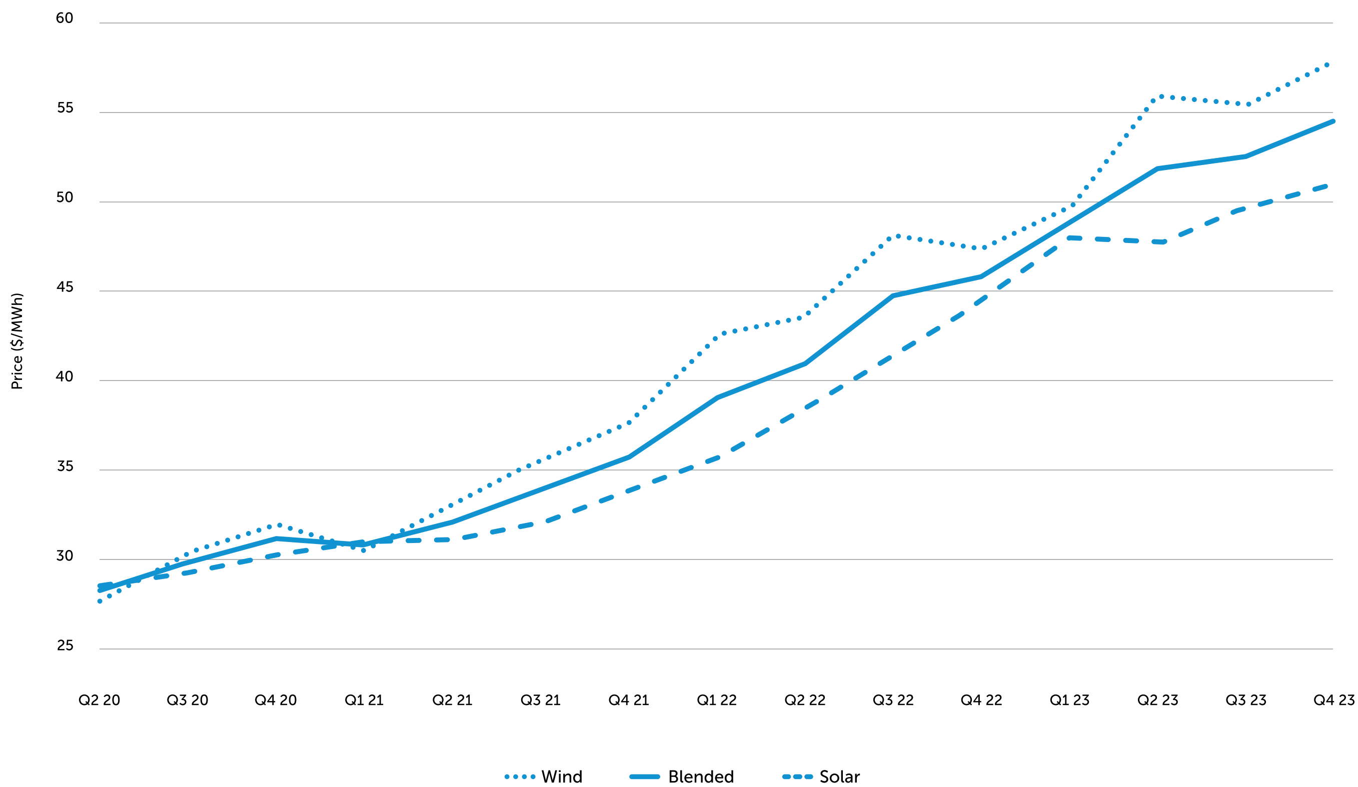



**Figure 3.** *PPA prices in the U.S. between 2020 and 2023*

Major drivers for this price increase are higher demand, higher cost of capital, higher inflation rates, higher transmission costs, higher risk premiums and trade policy changes. These drivers are detailed below.

**Higher demand:** Consistent with the global increase in demand for renewable generation, demand in the U.S. has also increased, especially after the passage of the Inflation Reduction Act, as illustrated in Table 1. According to the U.S. Energy Information Administration (EIA), the U.S. is expected to add 62.8 GW[6] of new capacity in 2024, 55% more than the 40.4 GW added in 2023. This represents the most capacity added annually since 2003.

Of this new capacity, the 36.4 GW of added solar is double the 18.4 GW added in 2023. Expected 2024 battery storage additions of 14.3 GW will be more than double the 6.3 GW added in 2023. The significant increase in demand for renewable energy, both domestically and globally, puts upward pressure on prices.

| | 2023 | 2024 |
|---|---|---|
| New capacity | 40.4 GW | 62.8 GW |
| Solar | 18.4 GW | 36.4 GW |
| Battery | 6.3 GW | 14.3 GW |

**Table 1.** *U.S. demand for renewable generation*

**Higher cost of capital:** Most of the renewable projects built by third-party developers and sold under long term PPAs are financed with up to 80% debt. Therefore, interest rates (especially long-term debt rates) affect PPA prices. U.S. long-term interest rates, as measured by the yield on 10-year U.S. Treasury Securities, have more than doubled in the past few years as shown by Figure 4 from the Federal Reserve's Economic Data.[7]

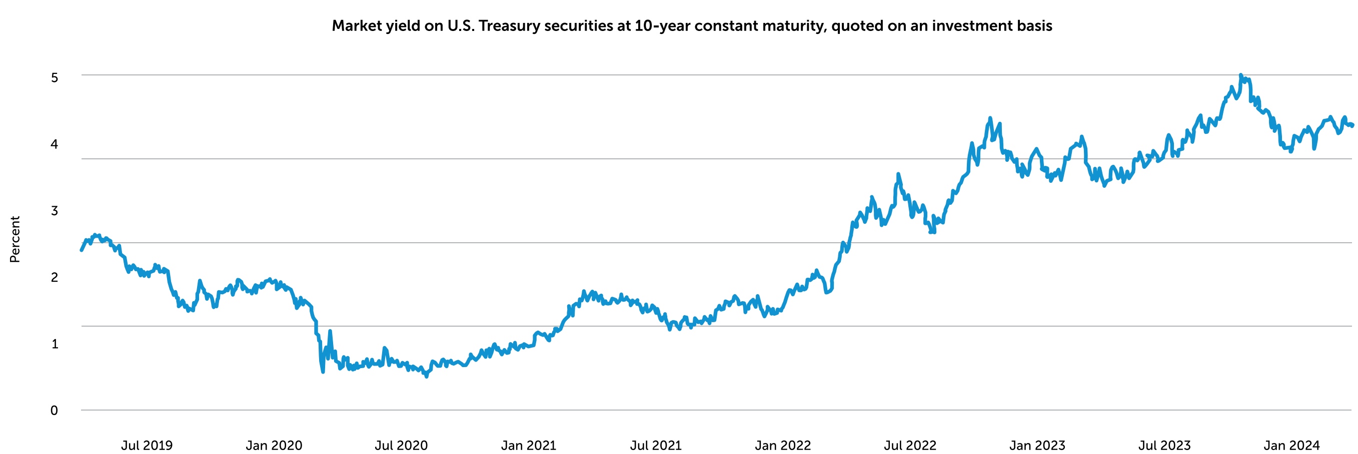



**Figure 4.** *Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on an investment basis*

[5] https://www.leveltenenergy.com/ppa

[6] https://www.eia.gov/todayinenergy/detail.php?id=61424

[7] https://fred.stlouisfed.org/series/DGS10

Corresponding to the 10-year Treasury Securities yield increases, the developer's cost of capital for financing a project has approximately doubled over the last few years from 3-4% to over 7%. This increased cost of debt has significantly increased the carrying cost of projects, raising PPA prices for utilities.

**Higher inflation:** According to the U.S. Bureau of Labor Statistics, the Consumer Price Index (CPI), which is a general measure of inflation, increased 17% in the past three years (January 2021 to January 2024), almost three times the prior three-year period (January 2018 to January 2021), when it increased 6%. This increase in CPI has affected all sectors of the economy, including the price of renewable generation. More specifically, labor costs have seen significant increases in the past few years as shown in Figure 5.

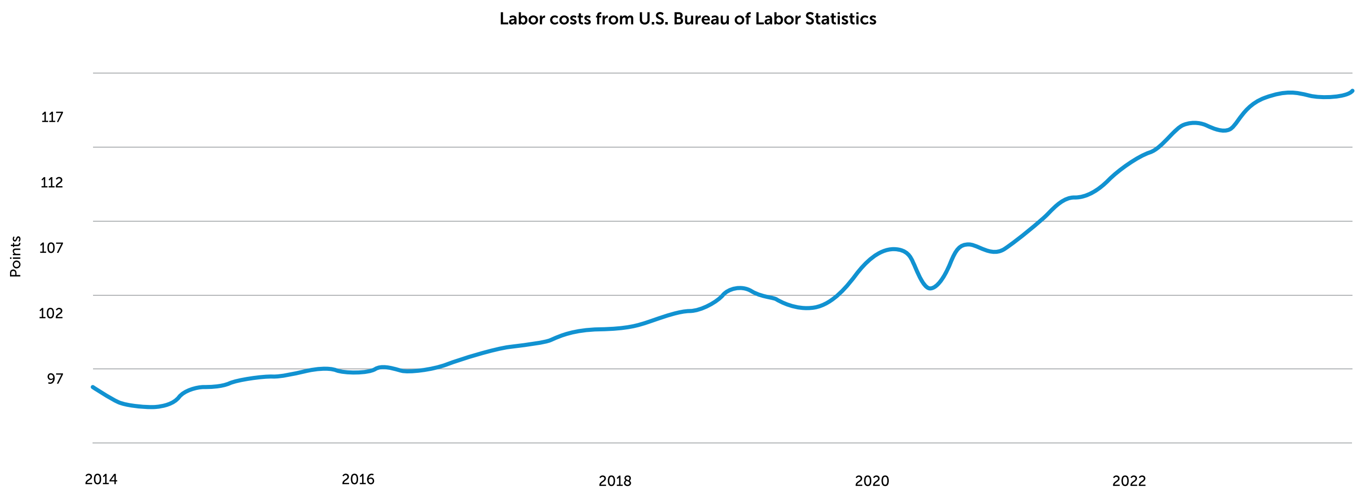



**Figure 5.** *Labor costs from U.S. Bureau of Labor Statistics*

Similarly, metal costs have seen more volatility and net increase over the past few years, as shown in Figure 6.[8]

**Higher transmission costs:** Transmission costs to interconnect renewables are increasing at two levels. First, inflation increases transmission interconnection equipment costs. Second, as more and more renewable resources are added to the grid, the cost to interconnect the next renewable project is often higher due to the need to upgrade the existing transmission infrastructure.

[8] https://fred.stlouisfed.org/series/PMETAINDEXM

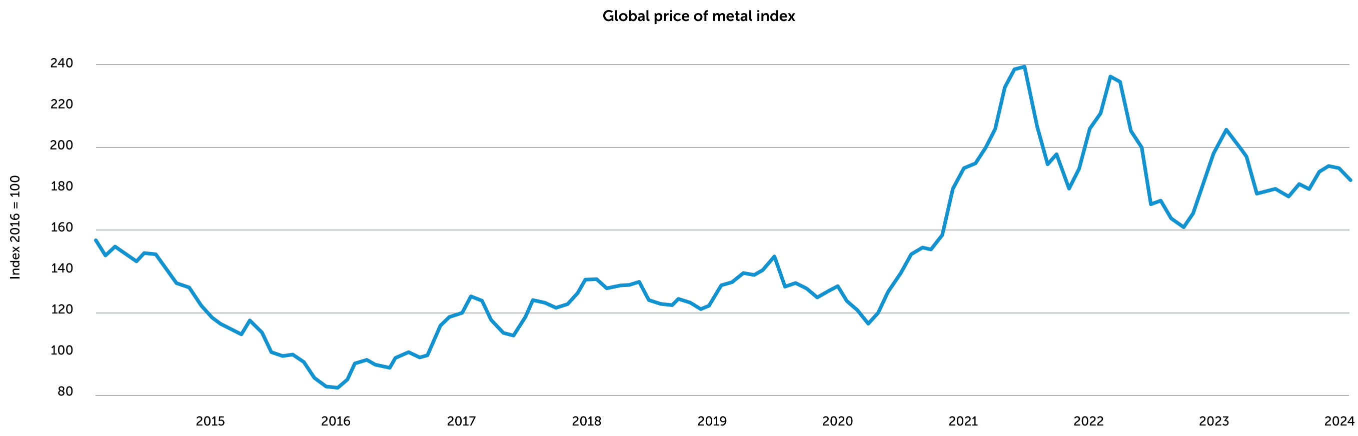



**Figure 6.** *Global price of metal index*

**Higher risk premiums:** Recent inflation and uncertainty about future inflation mean that developers assume the recent increase in equipment and labor prices will continue in the future. For example, developers have experienced a significant increase in engineering, construction, and procurement costs and assume these annual cost increases will continue. Recently, Platte River agreed to higher pricing on previously signed PPAs to enable project construction.

Additionally, Anti-Dumping and Countervailing Duties and Uyghur Forced Labor Prevention Act policies created uncertainty for imports from certain countries. These policies, coupled with other factors mentioned earlier, has pushed the price of renewable generation higher. The Inflation Reduction Act and other policies will expand domestic manufacturing, but it may take years before we see any downward pressure on prices.

## 3.5 Resource planning refresh in 2022

Following the pandemic and associated impacts on cost, Platte River staff updated the recommended portfolio from the 2020 IRP in 2022. The revised plan is called RP22 and includes the following:

### 3.5.1 Acceleration of renewable integration

The 2020 IRP had assumed all new generation and storage would come online on Jan. 1, 2030, after Platte River's last coal plant closed. RP22 adds renewables, storage and dispatchable resources while considering project development timelines and supply chain issues. Platte River seeks to have most, if not all, new resources ready by 2028 to give at least one full year of operating experience to Platte River staff before retiring Rawhide Unit 1. This accelerated timeline shows a gradual increase in renewable generation after 2025.

### 3.5.2 Extreme weather modeling

While Platte River's 2020 IRP simulated average weather and load conditions, the impact of Winter Storm Uri in February 2021 on power supply across the midsection of the continental U.S. provided a valuable lesson for enhancing future power supply reliability. During Uri, northern Colorado experienced extremely cold weather and saw little to no renewable generation for three days. We refer to this event of no renewable generation as a "dark calm" and simulated these events in future planning.

To enhance the reliability of the future power supply, RP22 simulates 24 years of hourly historical weather (with its unique hourly load, wind and solar profiles) and dark calm events. To meet this enhanced reliability requirement, RP22 added 62 MW of additional dispatchable capacity and reduced reliance on four-hour storage relative to the 2020 IRP recommended portfolio.

### 3.5.3 Expanded DER impact

Working closely with our owner communities, Platte River completed its DER strategy in July 2021. The strategy brought an expanded focus on DERs. Since the completion of 2020 IRP, customers have rapidly adopted EVs and distributed solar. Similarly, there is increased interest in heating electrification to replace natural gas-fueled heating. As a result, RP22 models rapid growth in DERs, including EVs, heating electrification and demand response.

### 3.5.4 Renewable supply chain impact

As discussed above, the renewable generation costs and project lead times increased after the pandemic. RP22 considers these increased costs and longer development times for the future portfolio.

## 3.6 Regulatory environment

This section outlines the legislative, regulatory and policy environment in which Platte River developed this IRP. It covers current legislative requirements with which Platte River must comply (both state and federal) as well as political assumptions that influenced the resource plan. This IRP addresses applicable state and federal laws, including those highlighted below.

Platte River is accountable to its board, to the Colorado Department of Public Health and Environment (CDPHE) through commitments made in its voluntarily filed Clean Energy Plan, and to the EPA through its contributions to Colorado's regional haze state implementation plan. The Colorado Public Utilities Commission does not regulate Colorado municipal utilities.

### 3.6.1 Colorado policy review

Since the passage of Platte River's RDP in 2018, Colorado's legislature has increased its attention to energy and environmental policies. Many recent bills impact utilities' resource planning and operations. The following bills are relevant to Platte River's resource planning and this IRP:

**HB19-1261:** The Climate Action Plan to Reduce Pollution set aggregated and sector-specific targets for reducing statewide greenhouse gas pollution. The bill set aggregate reduction targets at 26% by 2025, 50% by 2030 and 90% by 2050 compared to 2005 levels. The General Assembly encouraged consumer-owned electric utilities to file Clean Energy Plans demonstrating at least an 80% reduction in emissions by 2030 compared to 2005 levels. Platte River subsequently filed a voluntary Clean Energy Plan in line with the standards of HB19-1261. In addition to rulemakings for utilities, HB19-1261 also ushered in sweeping changes for other sectors, such as transportation and buildings, that have a direct impact on future electric load and utilities' resource planning.

**SB19-096:** This bill directed CDPHE's Air Quality Control Commission to collect greenhouse gas emissions data from emitting entities and report on the data to support the state in meeting its greenhouse gas emission reduction goals.

**HB22-1244:** This bill created a new program within CDPHE's Air Pollution Control Division to regulate toxic air contaminants. It also gave the Air Quality

Control Commission permission to create air toxics rules more restrictive than those of the federal Clean Air Act. Starting in 2024, regulated organizations must submit annual toxic emissions reports that the Air Pollution Control Division will make available to the public.

**SB23-198:** Expressing legislative concern that utilities are on track to meet the greenhouse gas reduction goals set out in HB19-1261, this bill requires any utility that submitted a Clean Energy Plan before Jan. 1, 2024, to model at least one portfolio that achieves a 46% emissions reductions by 2027 (as compared to 2005 levels) and at least one portfolio that achieves greater emissions reductions than the Clean Energy Plan submitted. The Air Pollution Control Division must subsequently confirm that utilities have adequate resources to achieve the 2030 clean energy target. As part of this IRP process, Platte River's board will consider portfolios that meet the requirements of SB23-198.

Table 2 illustrates how these Colorado policies are either considered in Platte River's RDP, modeled in this IRP or apply only to reporting functions.

| Colorado policy | Reporting | Considered by RDP | Modeled by 2024 IRP |
|---|---|---|---|
| **HB19-1261:** The Climate Action Plan to Reduce Pollution | | ✓ | |
| **SB19-096:** Collect Long-term Climate Change Data | ✓ | | |
| **HB22-1244:** Public Protections from Toxic Air Contaminants | ✓ | | |
| **SB23-198:** Clean Energy Plans | | | ✓ |

**Table 2.** *How Colorado policies are considered, modeled or reported by Platte River*

In 2018, Colorado Governor Jared Polis ran on a platform of achieving 100% renewable energy by 2040 and continues to direct his staff to achieve this goal. To drive and monitor Colorado's adherence to the greenhouse gas emissions reductions goals set out in HB19-1261, the state released its first Greenhouse Gas Pollution Reduction Roadmap in January 2021.

Concurrent with this IRP process, the Polis administration published its Greenhouse Gas Pollution Reduction Roadmap 2.0 in February 2024, which will accelerate Colorado's clean energy goals.

### 3.6.2 Federal policy overview

As a hydropower customer of WAPA, Platte River must file an IRP with WAPA every five years. This IRP document complies with WAPA requirements as detailed in Appendix A.

On June 16, 2020, Platte River announced its plans to retire Rawhide Unit 1 no later than Dec. 31, 2029. Colorado incorporated Unit 1's planned retirement into its state implementation plan for the regional haze program, making the retirement federally enforceable.

The U.S. Congress passed the Infrastructure Investment and Jobs Act, also known as the Bipartisan Infrastructure Law, in 2021 and the Inflation Reduction Act in 2022. Together these bills resulted in unprecedented federal investments in the clean energy transition through tax credits (including for not-for-profits that have historically not paid taxes and therefore have not been eligible for tax credits) and competitive grant programs. In response, Platte River has dedicated resources to submitting grant applications and to exploring tax credits for new renewable energy assets. To date, Platte River has mainly captured these benefits through PPAs with renewable developers, whose prices reflect federal subsidies. In partnership with trade associations such as the American Public Power Association and Large Public Power Council, Platte River is continuing to explore opportunities.

Platte River is carefully monitoring the EPA's new regulations on power plants with coal- or new natural gas-fired generating units. In May 2024, the EPA finalized rules to reduce greenhouse gas emissions from power plants. Platte River will continue to closely follow these and other federal developments.

# 3.7 Stakeholder engagement process

## 3.7.1 Outreach strategy

Platte River's communications, marketing and external affairs team worked closely with the transition and integration team to develop a robust community engagement strategy for the 2024 IRP. We collaborated with the four owner communities' distribution utility communications and community relations staff. Owner communities' staff recommended which neighborhood groups, community and nonprofit organizations and customer accounts to engage and helped coordinate presentations for city councils and council-appointed boards. This allowed for a more targeted approach on engaging with stakeholders across Platte River's service region, responding to questions and addressing concerns surrounding the reliability, environmental responsibility and affordability of future energy portfolios.

### 3.7.1.1 Community meetings

While some owner community stakeholder groups knew Platte River as a wholesale power provider, many constituents were unaware who generates their power and how. An added value of the IRP community meetings was the opportunity for citizens to engage with their community-owned generation and transmission utility.

Mindful of equity and access, Platte River either visited every group we presented to or provided a virtual option, provided information in Spanish and equipped meetings with translators and listening assistance options.

While the audiences were widespread across Platte River's service region with diverse backgrounds, there were general themes that surfaced. Those themes include:

- Discussions around customer behavior changes and impacts to resource planning
- The increasing trend of beneficial electrification and growth in demand and load
- Impacts of climate change and extreme weather modeling
- Clarity on what is a dispatchable resource
- Equity and affordability


Timeline
June
July
Aug
Sept
Oct
Nov
Dec
Feb
Resource planning
Load forecasting

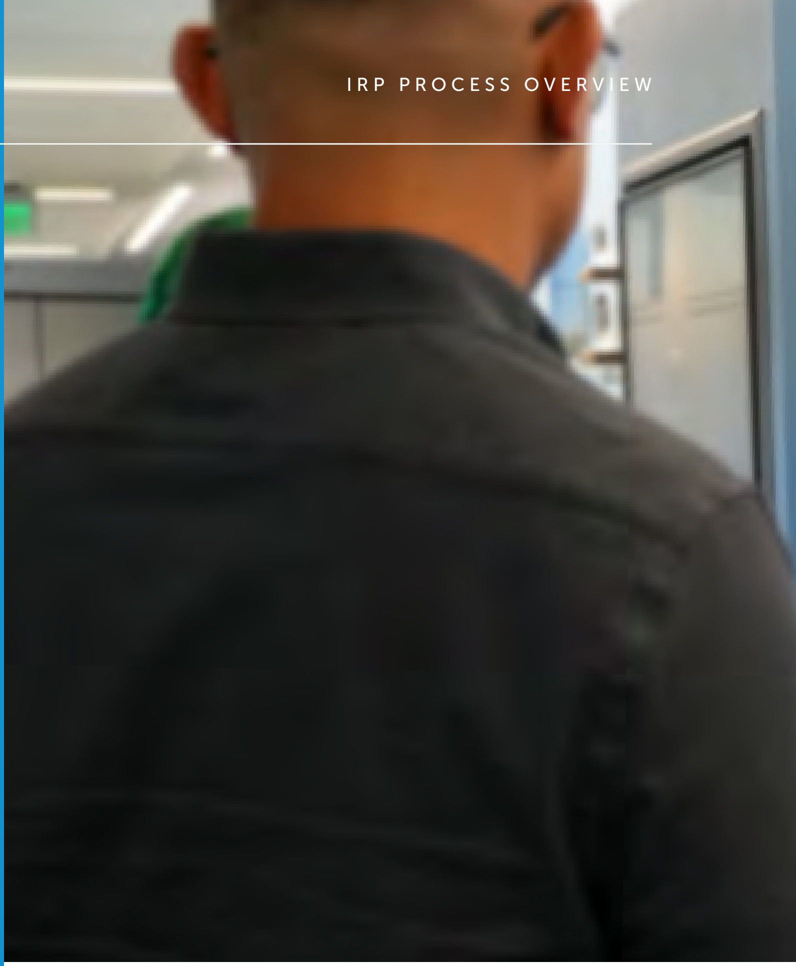
Each presentation gave the audience an opportunity to ask questions. The Platte River team continues to receive questions via email, social media and in-person. To date, we have logged and answered over 150 questions.

Presentations per owner community:

- Estes Park: 2
- Fort Collins: 8
- Longmont: 5
- Loveland: 4

Presentations per community group type:

- Neighborhood group: 2
- Community organization: 6
- Nonprofit: 5
- Customer account: 1
- Council-appointed board: 3
- City/town councils: 4



### 3.7.1.2 Business community engagement

Platte River engaged the business community primarily through downtown development authorities and local chambers of commerce: the Estes Park Chamber of Commerce, the Fort Collins Area Chamber of Commerce, the Longmont Chamber of Commerce and the Loveland Chamber of Commerce. We presented to chamber staff, committee appointees and members, sharing information about Platte River, the RDP, the IRP process and forecasts of our shared energy future. We captured questions and feedback from the business community, who are integral drivers of economic and workforce development in the region.


### 3.7.1.3 Consulting with industry experts

Platte River's resource planning staff actively consulted with national institutes and public power councils, including the Electric Power Research Institute (EPRI), National Renewable Energy Laboratory (NREL) and the Large Public Power Council.

## 3.7.2 Campaigns and resources

Platte River's first brand awareness and public education campaign launched soon after the start of our 2024 IRP community engagement. The parallel run of these two efforts aimed to educate the utility's service region about who Platte River is while driving users to Platte River's digital platforms to learn more about our aggressive decarbonization efforts.

Platte River used both organic and paid media to support community engagement activities for the 2024 IRP, including:

- Digital technologies like social media, email distribution and websites
- Cross-functional organic outreach through support from platforms across each owner community and distribution utility
- Paid media with advertisements placed in traditional and digital platforms with high visibility across each owner community
- Engagement with local media, including hosting an editorial meeting with local media partners

In addition, Platte River developed and maintains the following resources for continued engagement with the public.

#### 3.7.2.1 Microsite

Staff developed a detailed and interactive IRP microsite (prpa.org/2024irp) that is updated as information evolves and additional details are available. Members of the public are encouraged to visit this site to learn more about Platte River's plans and to access more in-depth information including the studies conducted as part of the IRP.

Our staff captured and answered all questions asked during the community engagement phase. These answers are provided in an appendix to this IRP. A subset of high frequency questions was extracted from the full list to develop a 'frequently asked questions' page published to the IRP microsite.

#### 3.7.2.2 Dedicated email

Platte River created a dedicated email for IRP specific questions and comments at 2024IRP@prpa.org. This approach allows for direct communication with engaged citizens and allows staff to track their contributions.

### 3.7.3 Results

The 2024 IRP reflects extensive collaboration among Platte River teams and gathering input from key stakeholders and the communities we serve. This process was designed to provide an open and transparent view of Platte River's resource planning strategy, accountability to our owner communities and the state of Colorado's clean energy goals and to underscore the value of equally maintaining our three foundational pillars.

One of the major takeaway messages we identified across each outreach effort: Platte River must continue to safely provide affordable and reliable power to its owner communities and their customers while addressing the evolving landscape in which we operate. Each owner community served by Platte River has set, or is in the process of setting, its own clean future initiative and is challenging Platte River to match these efforts to provide northern Colorado with electric service in an increasingly sustainable manner.

# 04

# Platte River's path to a clean, reliable energy future

## 4.1 Key variables and strategic considerations

Platte River considered whether the advancements identified in the RDP have been met while working toward the RDP goal. Other variables in this IRP include:

### 4.1.1 Load forecast

Load forecast refers to how load, or aggregate electricity demand, is changing and the impacts of those changes to the energy mix.

### 4.1.2 Energy and capacity planning

**Energy planning** involves managing the production and purchase of megawatt-hours (MWh) of electricity to meet customer demand efficiently and sustainably. Effective energy planning can decrease emissions by integrating renewable energy sources while maintaining reliability.

**Capacity planning** is crucial for utilities to have sufficient generation resources to meet peak load demands plus a reserve margin, known as the PRM. The PRM supports reliability and accommodates unexpected demand surges or generation outages.

#### Capacity vs. energy value

Resources may be developed primarily for their capacity value rather than their energy output. These resources may run infrequently but are critical during peak demand periods or emergencies. Their primary function is to be available when the system needs them the most, supporting grid stability and reliability.

### 4.1.3 Customer programs

Customer programs is the term to describe how existing energy efficiency programs are performing today, how they will evolve tomorrow, and how the behaviors that result from program adoption will impact load forecast.

Most of Platte River's existing customer programs are geared toward energy efficiency, access to renewable energy, support for low-income residents or electrification. Our IRP accounts for these programs' impact on total demand and peak demand for electricity.

The IRP also anticipates an increased focus on energy efficiency, battery storage and electrification. These needs will draw on existing customer programs and will be enhanced by new or expanded programs over the next several years.

### 4.1.4 Emerging technologies

Resource planning staff engaged with an engineering consulting team to evaluate the viability, long-term scalability and technological performance of emerging technologies. Platte River must balance the adoption of these technologies with the impacts they may have on the three foundational pillars.

### 4.1.5 Power markets

Participation in an organized market is needed for Platte River to achieve the clean energy transition. Over the years, Platte River has participated in numerous forums related to organized markets. Platte River, along with Xcel Energy, Black Hills Energy and later Colorado Springs Utilities, participated in the JDA for several years. The JDA was a small-scale, regionally focused market operated by Xcel Energy that allowed for more efficient use of generating resources and balancing renewable resources.

Although the JDA benefited Platte River, the opportunity to join an energy imbalance market was the next step in the path toward full energy market participation. This led to three of the JDA participants joining the SPP WEIS market in April 2023. While it functions like the JDA, the WEIS has a larger footprint and SPP serves as the independent market operator.

In September 2023, Platte River announced plans to join the SPP RTO West. Platte River, along with other utilities, expects to transition into this market on April 1, 2026. When the RTO West market is functioning, Platte River will sell all its generation into the market and purchase all its load obligations from the market.

### 4.1.6 Resource adequacy

Resource adequacy refers to the ability of Platte River to have sufficient resources to constantly deliver electricity to all consumers, even under challenging conditions. Resource adequacy is a critical aspect of resource planning and operation, to maintain enough generation capacity to meet the peak demand plus a reserve margin for unforeseen events, such as generator failures, weather events, sudden spikes in demand or other system disruptions.

### 4.1.7 Transmission and distribution infrastructure

As Platte River's energy portfolio continues to diversify, new resources will be interconnected to the transmission network. In a regional transmission network owned by more than one entity, the new resources may be interconnected directly to Platte River's transmission lines or to transmission lines owned by others.

Each transmission line owner manages a generator interconnection process to require the new generation resources to be interconnected in a way that does not adversely impact the reliability of the transmission network. New generation resources will require new interconnection infrastructure and if necessary, transmission network upgrades. The transmission network upgrades will be identified during the interconnect study process. The upgrades may include new transmission lines or modifying existing transmission lines.

As new resource projects are established, network upgrades or modifications will be evaluated and identified. Platte River has included the costs to fund future transmission projects in our long-term capital budget. Current budget estimates will be refined as the details of the new resources are identified.

### 4.1.8 DER adoption and integration

Traditionally, customer electricity needs consisted solely of aggregate electricity demand. With the growth of DERs, today's customer demand must also include a seamless and economic integration of distributed resources.

## 4.2 Navigating challenges and maintaining the foundational pillars

The foundational pillars serve as guideposts for all Platte River activities, including the resource planning and modeling activities documented in this IRP.

### 4.2.1 Reliability – dispatchable capacity

Dispatchable capacity refers to any resource that can start, stop, and change output level quickly to produce more or less power when needed. The reliability challenges during extreme weather events and dark calms (characterized by the absence of solar and wind energy due to adverse weather conditions for multiple days) highlight the vulnerability of serving load with weather-dependent energy sources. These events underscore the critical role of dispatchable capacity in maintaining power supply.

Platte River commissioned a study with ACES to analyze different weather patterns from the past five decades across a broad region to understand the frequency and impact of extreme weather and dark calm events. The findings emphasize the need for a diversified energy portfolio and supply strategies that can withstand varying weather conditions, including rare and extreme events.

The future of energy reliability hinges on supporting renewable resources with dispatchable resources (including innovative energy storage solutions) to provide continuous power supply during all weather scenarios.

### 4.2.2 Environmental responsibility – cost of carbon

The portfolios modeled in this IRP assume that future electricity prices will also include carbon taxes.

The carbon-imposed cost portfolio imposes additional costs disincentivizing dispatch of high-carbon energy sources unless needed to maintain reliability of the system even after accounting for their environmental impact. This factors environmental ramifications of carbon emissions into decision-making, steering energy strategies toward more sustainable pathways.

The evaluation process for including technologies in a carbon-imposed cost portfolio prioritizes renewable energy sources like wind and solar due to their minimal carbon footprint. Dispatchable capacity resources are also considered for their potential to balance reliability with reduced emissions, aligning the portfolio with environmentally responsible objectives.


### 4.2.3 Financial sustainability – rates and affordability

As a not-for-profit utility, Platte River's revenues from its wholesale power rates fund ongoing operations and are reinvested into the system for the benefit of the owner communities. The owner communities' distribution utilities integrate Platte River's wholesale rates into their retail and commercial electric rates.

Platte River's rate-setting policy calls for established service offerings and supporting rate structures that complement the strategic objectives and values of the organization. Platte River's rate structure strives to meet the following objectives:

- Align wholesale pricing signals with cost of service
- Adapt to cost structure changes
- Integrate noncarbon resource additions

In support of Platte River's foundational pillars of providing reliable, environmentally responsible and financially sustainable energy and services, and Platte River's mission, vision and values and strategic initiatives, the strategic financial plan provides direction to preserve long-term financial sustainability and manage financial risk. The objectives of the strategic financial plan are:

- Generate adequate earnings margins and cash flows

- Maintain sufficient liquidity for operational stability
- Maintain access to low-cost capital
- Provide wholesale rate stability
- Maximize cost savings through pricing signals that provide system benefits and revenue stability
- Navigate resource acquisition costs increases and delays

Platte River is also subject to financial and rate requirements in the Power Supply Agreements and the General Power Bond Resolution. Platte River's Board of Directors has the exclusive authority to establish electric rates and must review rates at least once each calendar year.

To meet these objectives and requirements, staff established financial metrics and rate stability strategies, taking into consideration rating agency guidelines. Following its strategic financial plan, Platte River will maintain long-term financial sustainability by implementing appropriate rates and strategies that:

- Reduce significant single-year rate hikes
- Provide greater rate predictability to support owner communities with more accurate, long-term planning
- Maintain a strong financial position and AA credit rating

Competitive wholesale rates give the owner communities economic benefits for their customers. Platte River strives to maintain services and rates offered at competitive prices compared to similar services and products provided by other wholesale electric utilities in the region. Platte River's fiscal responsibility and rate stability strategies help reduce long-term rate pressure and give the owner communities greater rate predictability.

Platte River's long-term rate forecast is prepared and presented to the board of directors in the spring of each year. The IRP results, along with the most current assumptions, will be included in the rate forecast prepared in spring 2024.

# 05 Electricity demand

## 5.1 Load forecast methodology and data

The future load forecast is a key input for the 2024 IRP. It serves as the foundation for decision-making around resource allocation, capacity planning and infrastructure development. Accuracy of future load forecasts is critical for new resource development and investment in new technologies.

Historically, utility load forecasts were driven by weather, economic activity and efficiency improvements. While these are still the primary drivers, DERs are rapidly becoming a significant contributor to future electricity demand. While all DERs are important, energy efficiency, distributed solar, EVs and beneficial electrification are the primary contributors to the future load forecast. These DERs impact the load forecast in different ways. For example, energy efficiency reduces load, distributed solar reduces net load during the day, EVs add load across the day (especially in the evenings), and beneficial electrification increases load in colder months. This complex combination of opposing impacts increases the uncertainty in expected future load. Consequently, it increases the need for flexible plans and frequent plan updates, to provide reliable power supply under wide-ranging future load scenarios.

Load forecasting models rely on historical data to develop future forecasts. Most DERs are in early stages of development and there is very little historical data available for them. Therefore, Platte River developed a load forecast based on history without considering DERs. A separate forecast for DERs was developed based on expected adoption rates. The two forecasts were then merged to develop a composite or net load forecast. This composite load forecast was used in the Plexos model to build the supply side resource mix.

# 5.2 Load forecast without DER

Platte River hired The Energy Authority (TEA), a third-party consultant, to develop a 20-year load forecast for the planning period of 2024-2043. TEA developed a load forecast without considering DERs, referred to as the base load forecast. TEA developed a forecast of monthly energy consumption and monthly peak demand as well as hourly load shapes.

## 5.2.1 Methodology

The monthly load forecast used a “least squares linear regression” model, using historical data to derive a linear relationship between a dependent variable and one or more independent variables. The dependent variable was forecasted using linear relationships and projections for each independent variable as discussed below.

Forty years of historical weather data, along with 20 years of load and economic data, were used to train three linear regression models. The first model considered total monthly energy as the regression’s dependent variable. The remaining two models considered peak load as the dependent variable, with a model specifically for June through September and another for all remaining months in the year. This split was due to the contrast in peak load history between summer, which has grown consistently, and winter, which has seen a slight decrease since the late 2000s. Figure 7 illustrates the total and peak load history for Platte River, aggregated by year.

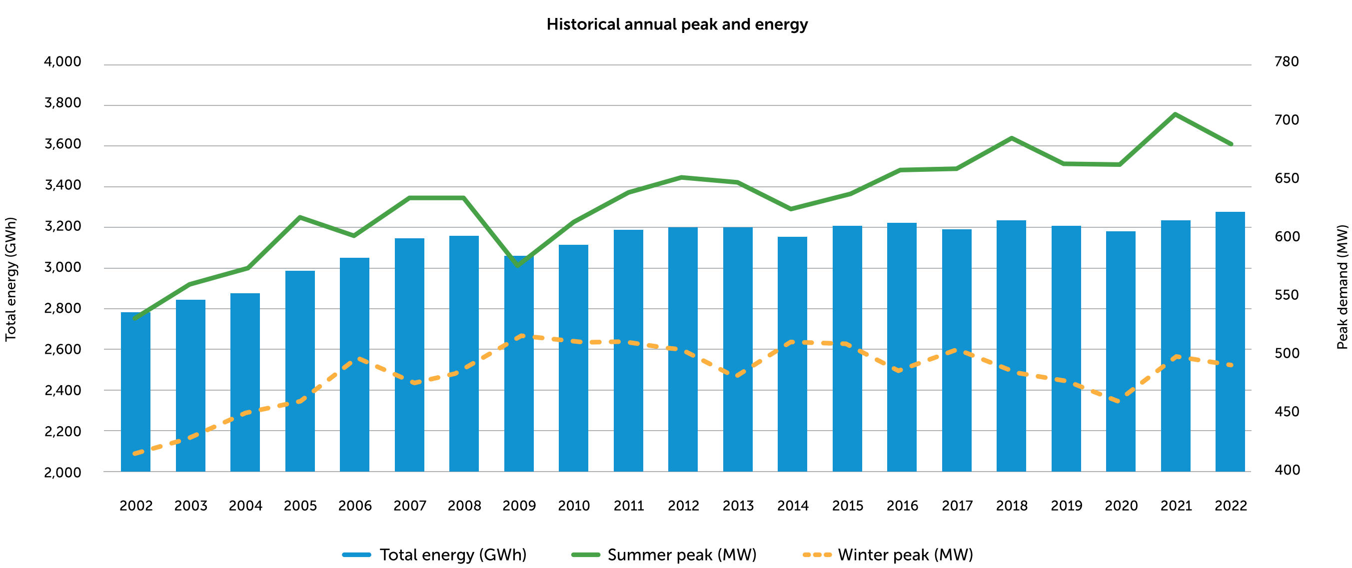



**Figure 7.** *Historical annual peak and energy*

Once the regression model was trained using historical data, a projection for each of the forecast drivers was input into the three models, creating monthly forecasts for total energy and peak load.

## 5.2.2 Forecast drivers

Future load growth can be driven by weather trends, economic factors or specific changes in customer usage patterns. To project future load patterns, Platte River's linear regression model used temperature, number of households and changes in air conditioning use.

**Weather and seasonal impacts.** One of the fundamental metrics to quantify the severity of weather is degree days. This metric takes the difference between the average daily temperature and a set point. In this case, the set point was 65 degrees Fahrenheit (˚F). Heating degree days take the sum of this calculation for temperatures below 65˚F, while cooling degree days use this calculation for temperatures above 65˚F. The distinction between heating and cooling degree days was made because hot and cold weather have different impacts on customer energy usage.

Based on the past 40 years of historical temperature data, a weather-normal forecast was developed for both heating and cooling degree days. Forty years of data were used to better capture the slight warming trend that has been observed in temperature history. This warming trend was incorporated into the weather-normalized forecast, resulting in a slight decrease in annual heating degree days and a slight increase in annual cooling degree days over time, as illustrated in Figure 8.

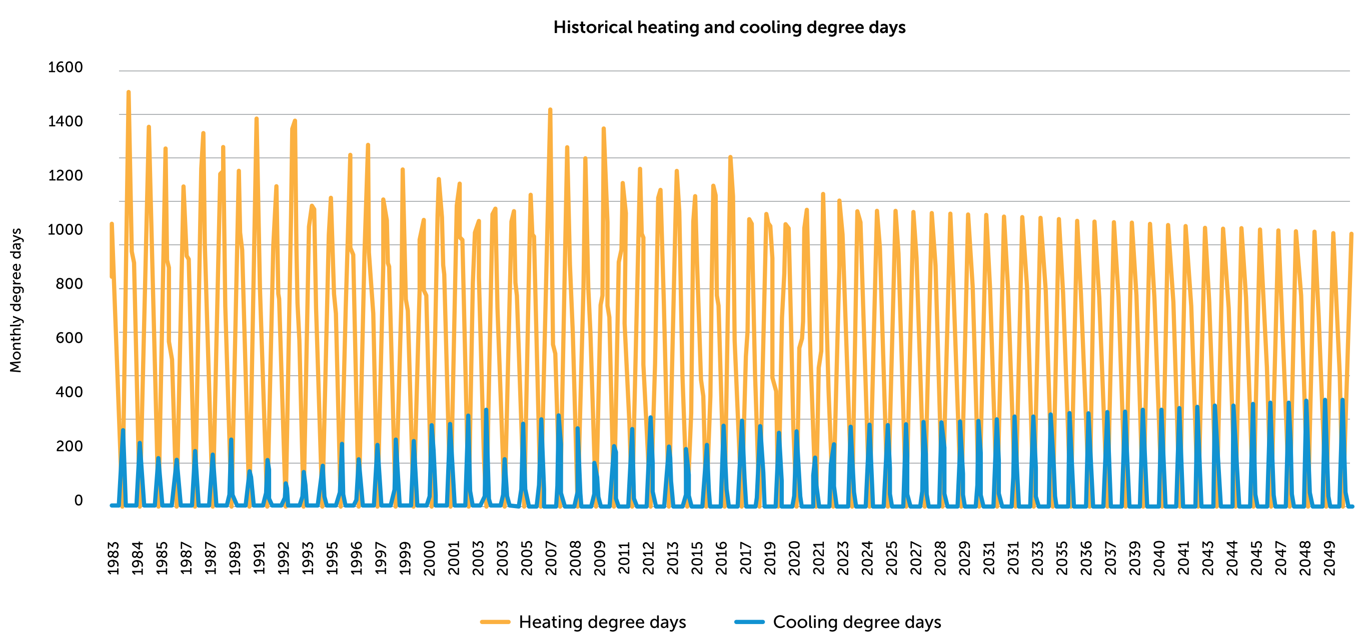



**Figure 8.** *Historical heating and cooling degree days*

Another factor incorporated into the load forecast model was the month of the year. This was used both to smooth the monthly forecast and to better consider seasonal impacts that may not be captured solely using heating or cooling degree days.

**Number of households.** Number of households was used to project economic growth within Platte River's service territory. These projections were obtained for Larimer County from Woods and Poole, an economic forecasting firm. While sections of Platte River's service territory exist in surrounding counties, the model assumes that economic growth in Larimer County reflects the growth of nearby areas as well. Growth in number of households is expected to continue to soften through the 2030s, following the trend observed since 2011. From 2040 onward, growth in number of households slightly flattens as illustrated in Figure 9.

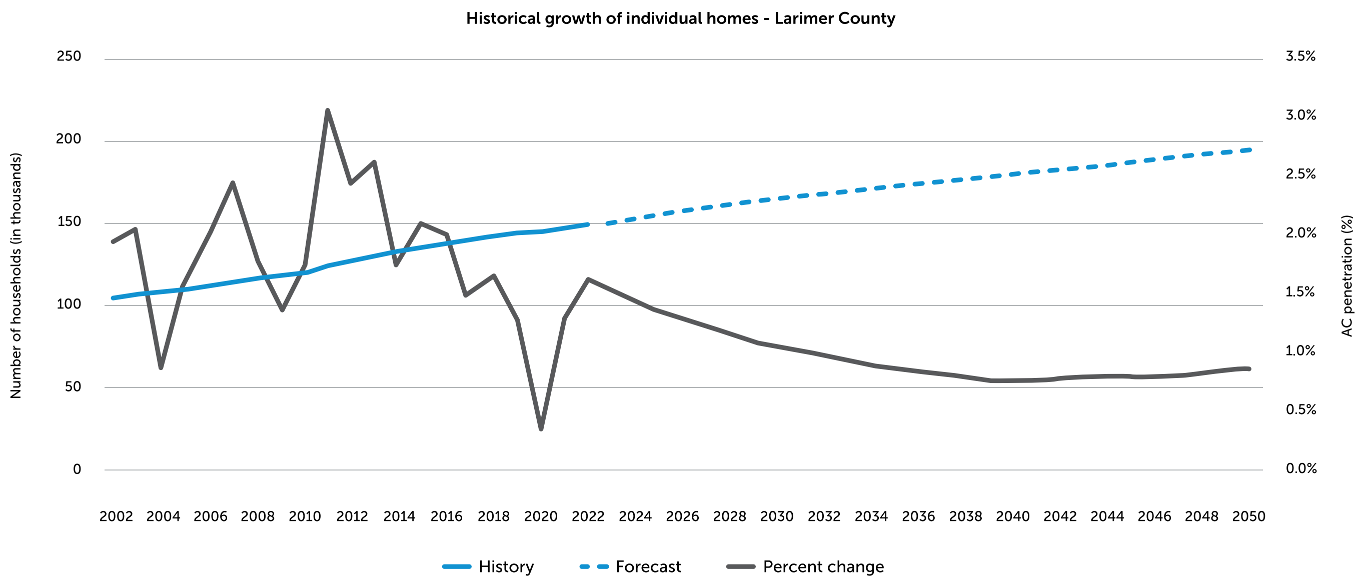



**Figure 9.** *Historical growth of individual homes*

**Air conditioning use.** A large driver for load growth over the past 20 years is an increase in the percentage of single-family homes with central air conditioning. This has increased both total energy consumption and peak demand during the summer months. Growth in air conditioner use is expected to slightly decrease in the future, with an average of 0.6% year-over-year increase through 2050, as illustrated in Figure 10.

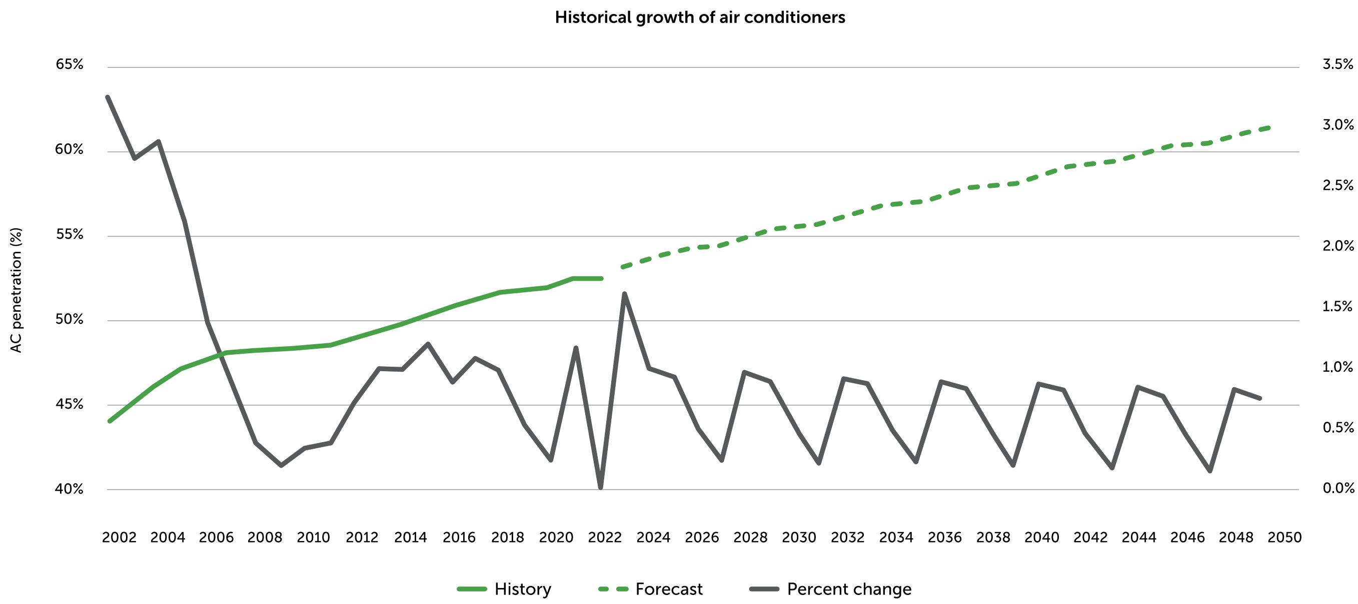



**Figure 10.** *Historical growth of air conditioners*

## 5.2.3 Forecast results

Figure 11 displays the annual total energy forecast, summer peak demand and winter peak demand through 2050. The growth in summer peak demand is expected to outpace growth in total energy, reflecting the trend observed since the early 2010s. While winter peak demand is projected to increase, it is at a lower rate than both summer peak and total energy forecasts. Average summer peak and total energy growth rates for the first 10 years of the plan are shown in Table 3.

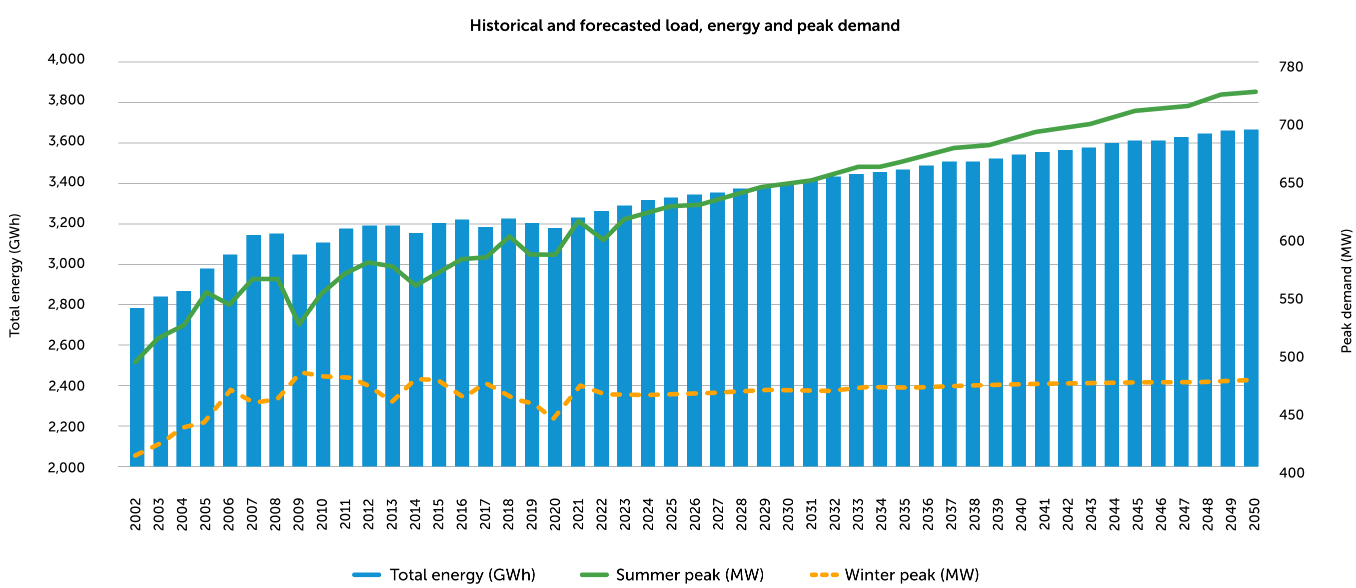



**Figure 11.** *Historical and forecasted load, energy and peak demand (base forecast without DERs)*

| 2024 – 2033 year-over-year average growth – base load forecast | |
|---|---|
| Total energy | 0.5% |
| Summer peak load | 0.8% |

**Table 3.** *Average annual load growth, energy and peak demand*

## 5.2.4 Hourly load shape

In addition to monthly forecasts, an hourly load shape forecast was developed for hourly dispatch modeling purposes. Rather than using a linear regression tool, a more robust model was chosen to develop the hourly shape due to the many nuances observed between hourly load and temperature changes over time. Hourly load data for 2013-2022 and temperature data for 2002-2022 was input into the model. The model created an hourly weather normal temperature forecast using the rank and average method. After the hourly load forecast for 2023 was developed, the total energy and peak load shape for each month was then normalized to the monthly projections for 2023. While there were not large discrepancies between the hourly and monthly model projections prior to normalization, this was done to ensure consistency between the two forecasts.

Figure 12 compares the average hourly shape, by month, for the 10 years of historical hourly data and the 2023 projections. There are increases in average hourly load between the load history and forecast, but these reflect load growth observed during 2013-2022. The forecasted load shape is commensurate with historical load shapes.

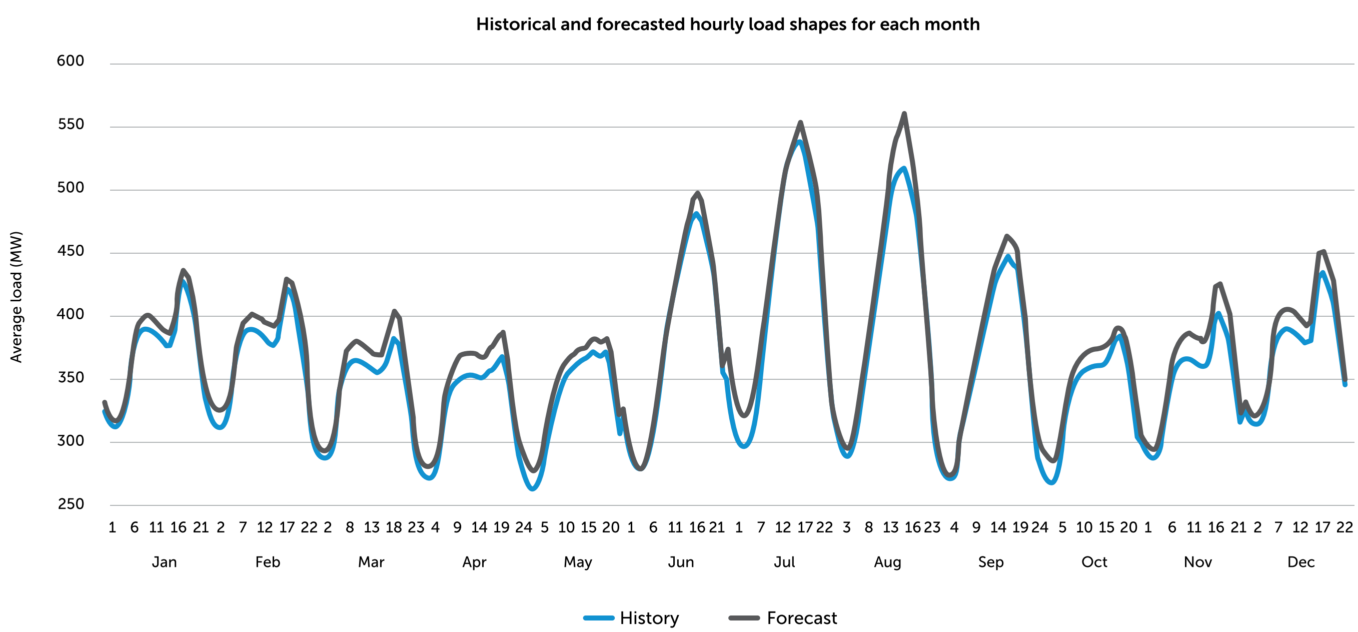



**Figure 12.** *Historical and forecasted hourly load shapes for each month*

# 5.3 DER integration, flexible DERs and the virtual power plant

The term "DER" encompasses a range of technologies installed and used at a customer's premises or within the distribution system. DER can be either on the customer or utility side of the meter. These assets potentially provide advantages to both the electric system and customers alike. These resources include energy efficiency, building electrification, transportation electrification, distributed generation, distributed energy storage and demand response.

DERs are, as stated in the name, resources. For resources to provide value, they must be put to effective use. Effectively using DERs to provide system-wide benefits is often referred to as "integrating" DERs. Integrating DERs means they have been made a functioning part of the electric system. This includes some or all of the following:

**Visibility and forecasting.** DERs must be "visible" to and predictable by electric system planners and operators for their effects to be taken into consideration. To support system planning, DER impacts must be forecast years in advance. To support system operations, DER forecasts must look seconds, minutes, or days into the future.

**Dispatchability or control.** Flexible DERs can be controlled or dispatched by utility system operators to maintain reliability or to achieve system-wide financial benefits.

**Customer awareness, engagement and participation.** The customer is provided support and services to help them understand their opportunities, benefits and responsibilities as participants in the electric system.

When flexible DERs are integrated in this manner and aggregated into coordinated operational programs, they are considered a virtual power plant (VPP). A VPP is a network of aggregated flexible DERs that can be controlled by Platte River and the owner community distribution utilities through advanced software to support grid reliability and financial sustainability.

Modeled in forecast

**Energy efficiency**

Save energy and save money by using energy more efficiently

**Electrification**

Reduce greenhouse gases by replacing fossil fuel use with increasingly decarbonized electricity

Flexible DER as part of a VPP

**Distributed generation**

On site noncarbon generation

*Solar generation*

**Demand response**

**Distributed energy storage**

Shift energy to align electric use to renewable availability and to decarbonize the electric system in a cost effective and reliable manner

*EVs, batteries and traditional demand response*

### 5.3.1 DER forecast studies

Platte River commissioned two DER forecast studies to support DER and resource planning. The first, Platte River Power Authority Beneficial Building Electrification Forecast, Mar. 12, 2022, was completed by Apex Analytics, LLC ("Building Electrification Study"). The second, Distributed Energy Resources Forecast and Potential Study, Aug. 28, 2023, was completed by Dunsky Energy+Climate Advisors ("DER Study").[9] A summary of the studies and their results is included below, and the full studies are available in the appendices of this report.

The Building Electrification Study scope included the following:

- Study period: 24 years (2023 through 2046)
- Building electrification categories: space heating, water heating and cooking
- Sectors/segments: residential and commercial
- Scenarios: three market potential scenarios that consider market, policy, and technology factors and inputs (for example, technology cost and performance; federal, state and local codes, standards, or incentives) and program or utility factors and inputs (like incentives or rates)
- Outputs: annual energy impacts, hourly and peak demand impacts

The DER Study scope included the following:

- Study period: 20 years (2024 through 2043)
- DER categories: energy efficiency, transportation electrification, distributed generation + storage, and demand response (or flexible DER, including EV charge management, battery storage management and traditional demand response)
- Sectors/segments: residential single family, residential multi-family, small commercial, large commercial
- Scenarios: three market potential scenarios that consider market, policy, and technology factors and inputs (for example, technology cost and performance; federal, state, and local codes, standards, or incentives) and program or utility factors and inputs (like incentives, rates, or avoided costs)

[9] Platte River did not consider cogeneration and district heating/cooling in these studies because of the lack of interest by our customers and the future trend of electrifying heating and cooling to reduce gas burning.

- Outputs: technology adoption (number of units), annual energy impacts, hourly and peak demand impacts, program metrics (budgets)

The results of these studies inform load forecasts and DER program plans as discussed below.

## 5.3.2 Energy efficiency

Energy efficiency programs help customers reduce their energy consumption through a variety of interventions, including outreach, education, contractor engagement and incentives. Platte River and the owner communities deliver energy efficiency programs under the Efficiency Works™ brand, jointly funded and administered by Platte River and its owner communities. These programs give communities a cost-effective way to manage load growth, reduce carbon emissions and help customers reduce electricity costs, and provide a cost-effective option when compared to the cost of supply-side resources otherwise needed.

### 5.3.2.1 Energy efficiency forecast study results

The DER Study evaluated the energy efficiency potential, identifying three adoption scenarios: low, medium and high. The adoption scenarios were evaluated based on three other utility potential studies, taking into consideration local factors, such as the owner communities' customer segmentation, historical participation data for existing Platte River energy efficiency programs and the building electrification forecast study identifying heat pump adoption rates. Two of the key takeaways from the study include:

- Platte River could achieve an average incremental savings rate of almost 0.78% of annual load each year between 2024 and 2030 in the low scenario, 1.15% in the medium scenario, 1.71% in the high scenario. This would come at a cumulative cost (2024-2030) of about $105 million, $200 million and $460 million, respectively.

- Energy efficiency savings for lighting, heating, ventilation and air conditioning (HVAC) pumps and fans and plug load (energy used by equipment that is plugged into an outlet) make up over 60% of total forecasted savings by 2043 for the commercial sector. For the residential sector, heating provides almost 60% of the energy efficiency savings, due in part to growing residential heating electrification, followed by plug load and domestic hot water.

The study applied the energy efficiency potential scenarios to the estimated customer baseload forecast. Figure 13 shows the effect of energy efficiency on load forecast and Figure 14 shows energy savings by market segment.

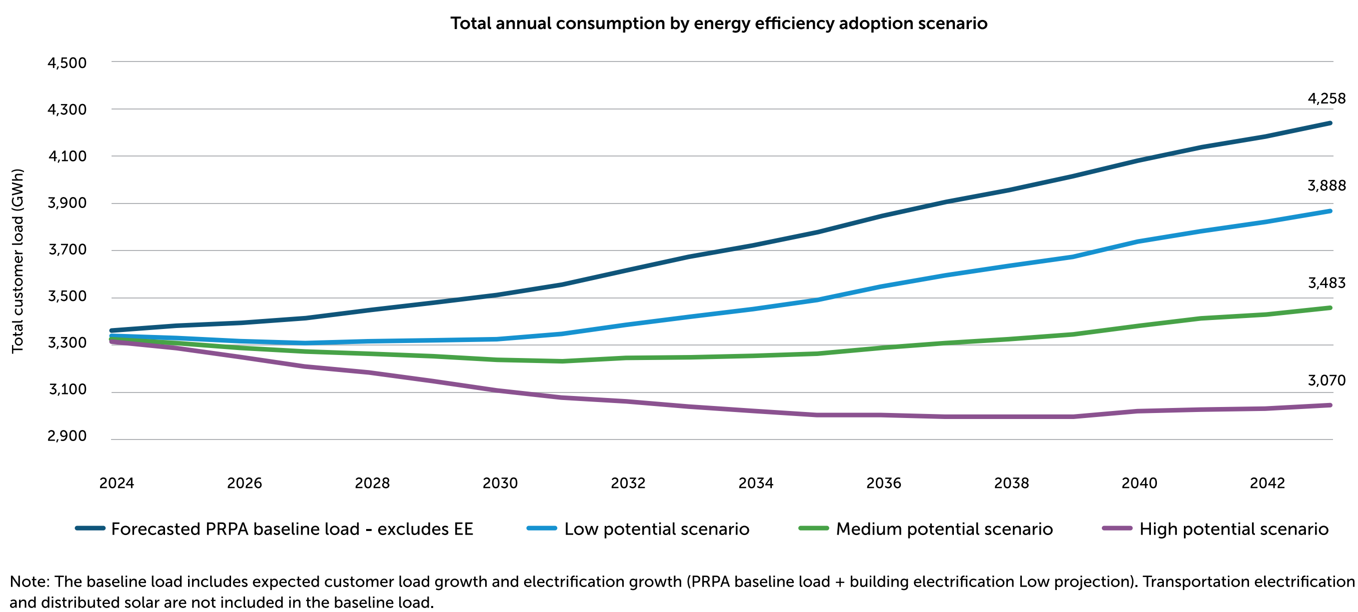



**Figure 13.** *Total annual consumption by energy efficiency adoption scenario*

Platte River continues to invest significant resources in a portfolio of energy efficiency programs, which include some of the highest incentives in the region. These investments are intended to help avoid the need for new generation resources due to customers using energy more effectively.

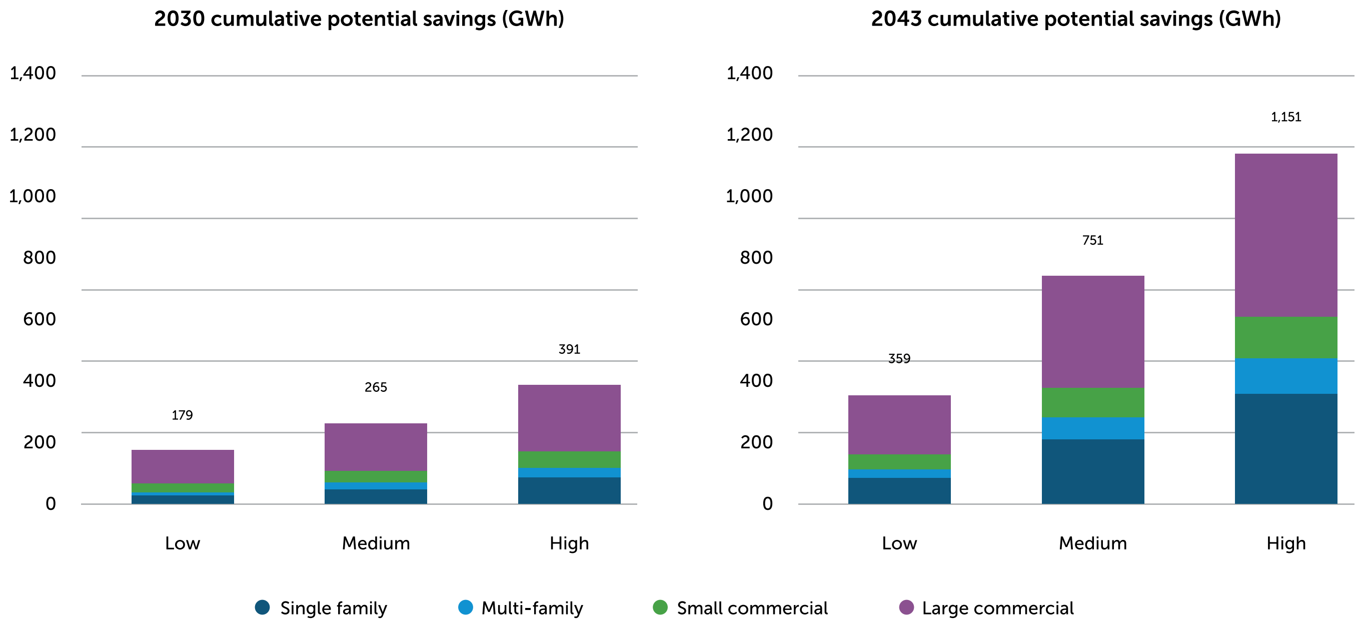



**Figure 14.** *Cumulative potential savings (GWh)*

However, current participation rates are consistent with the low forecast contained in the DER study. Platte River plans to continue investment in energy efficiency at current levels through 2030 and beyond with adjustment for inflation, as long as the investment provides value through customer participation and energy-saving benefits. See figures 15, 16 and 17 for estimated future investments and associated savings within the owner communities for energy efficiency services. These ongoing investments in energy efficiency services will continue to evolve and provide a strong foundation of programming for other DER technologies to build upon in future years.

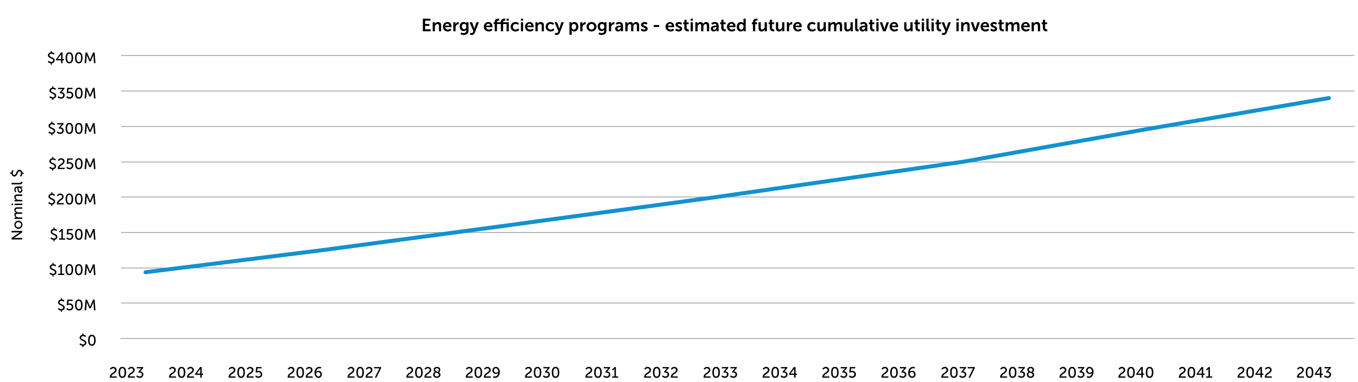



**Figure 15.** *Energy efficiency programs - estimated future cumulative utility investment*

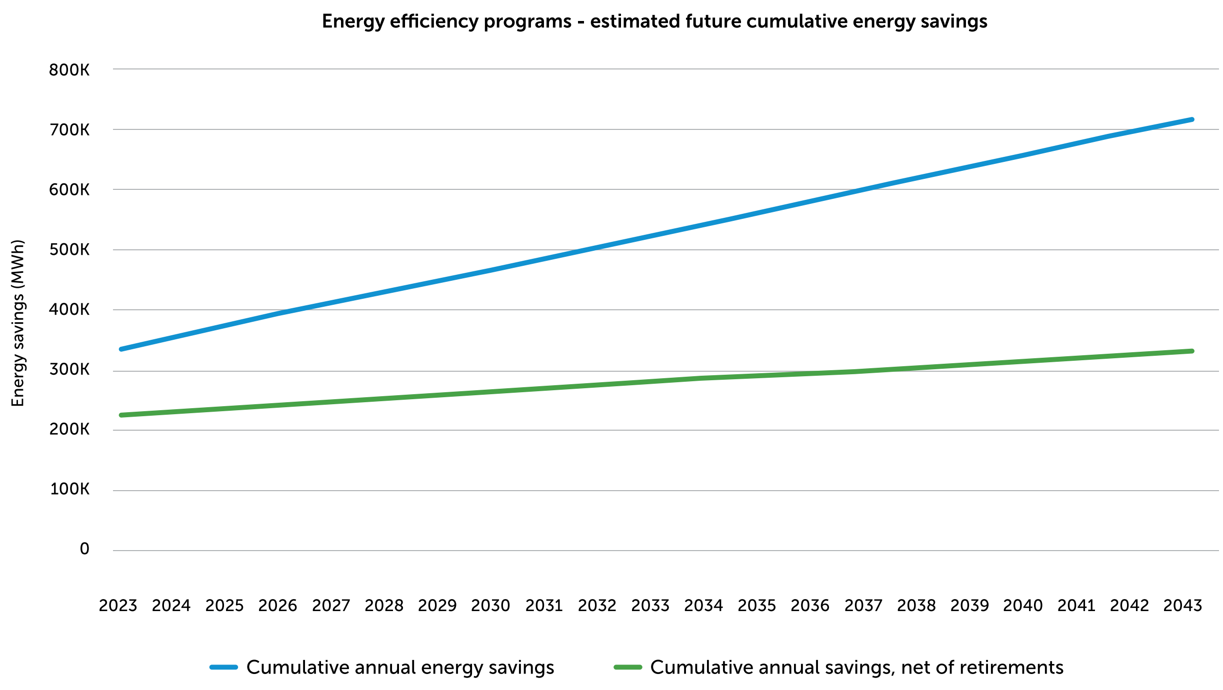



**Figure 16.** *Energy efficiency programs - estimated future cumulative energy savings*

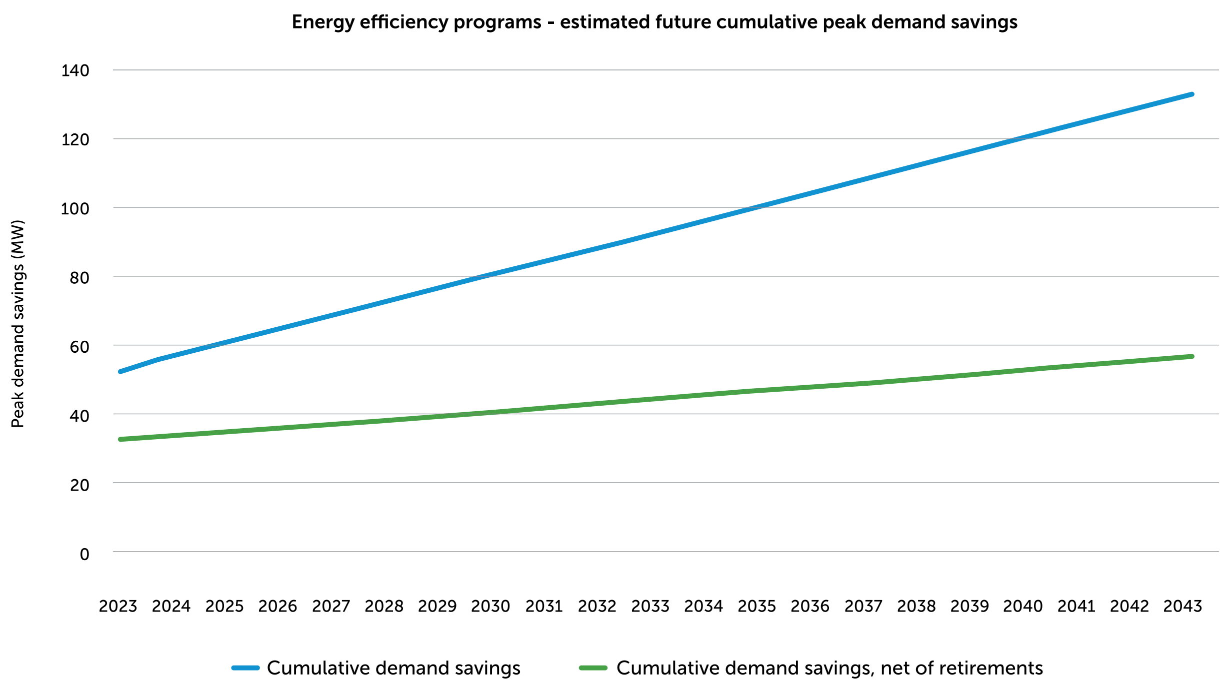



**Figure 17.** *Energy efficiency programs - estimated future cumulative peak demand savings*

## 5.3.3 Electrification

### 5.3.3.1 Buildings

Building electrification refers to new uses for electricity that replace other sources of energy used in buildings. When building electrification provides additional economic benefits, grid benefits and environmental benefits, it is referred to as beneficial building electrification. Typically, building electrification involves the replacement of natural gas or propane appliances in residential and commercial properties with more carbon-efficient appliances that consume electricity.

As Platte River's owner communities pursue carbon emission reduction and as Platte River decarbonizes its generation, building electrification becomes an attractive alternative that can be incorporated into existing Efficiency Works customer programs.

**Building electrification forecast study results.** In 2022, Platte River completed a Building Electrification Study to provide a range of forecasts for building electrification adoption and effects on electric consumption. The study evaluated the adoption electrification of end uses with a focus on those with the most significant potential: space heating, water heating and cooking. Three growth scenarios were considered—low, medium and high—based on varying levels of policy interventions and technology types. Medium utility incentives were assumed for all three scenarios. Some key findings from the study include:

- Only minor impacts on overall electricity consumption are expected through 2030. However, starting in the 2030s, building electrification impacts become larger.
- Most of the energy and demand growth occurs in the winter; summer impacts are minimal.
- Full electrification of heating during extreme cold will cause Platte River to become a winter peaking utility sometime after 2035.
- Policies requiring all-electric new homes or businesses could push impacts sooner – winter peaking will occur within five to 10 years of requiring all-electric new homes.
- Electrifying residential space heating with heat pumps is the highest impact building electrification technology and supports ongoing energy efficiency options.
- Full electrification of heating causes significant cost and reliability challenges.
- Without program or policy support, or significant changes to heat pump technology, efficiency and economics, cost and accessibility challenges will limit adoption of building electrification.

Results of the study are shown in Figures 18 and 19. Additional details on building electrification impacts can be found in the APEX Analytics study at prpa.org/2024irp/information.

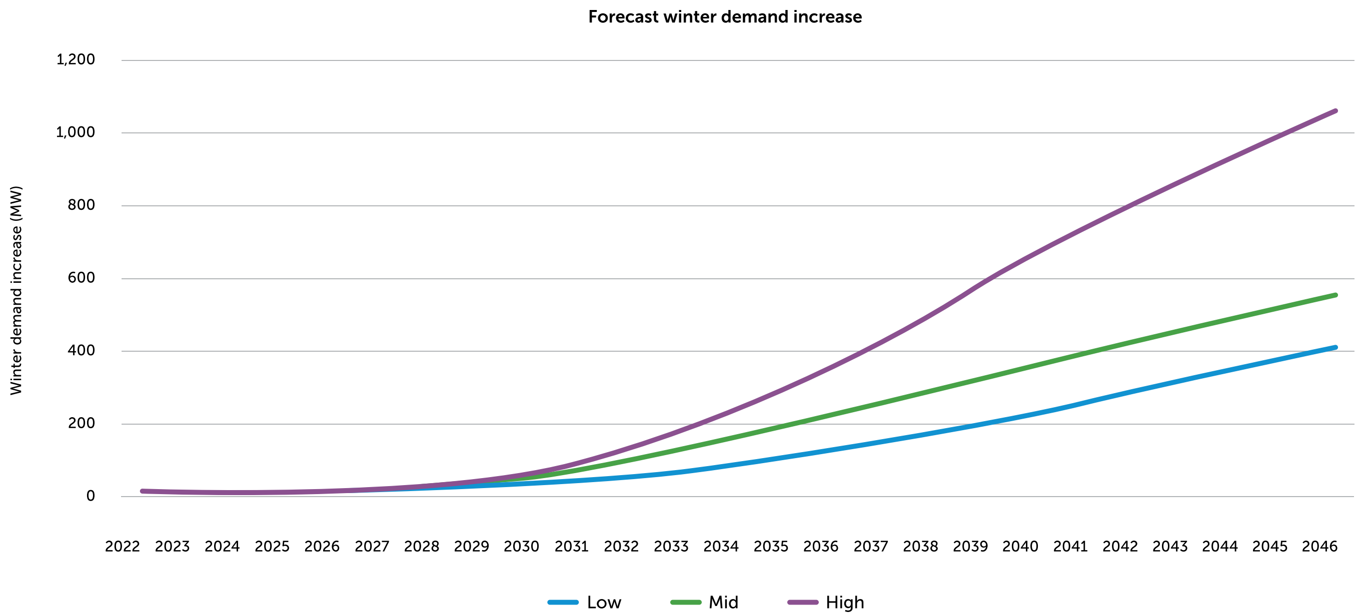



**Figure 18.** *Forecasted winter demand increase*

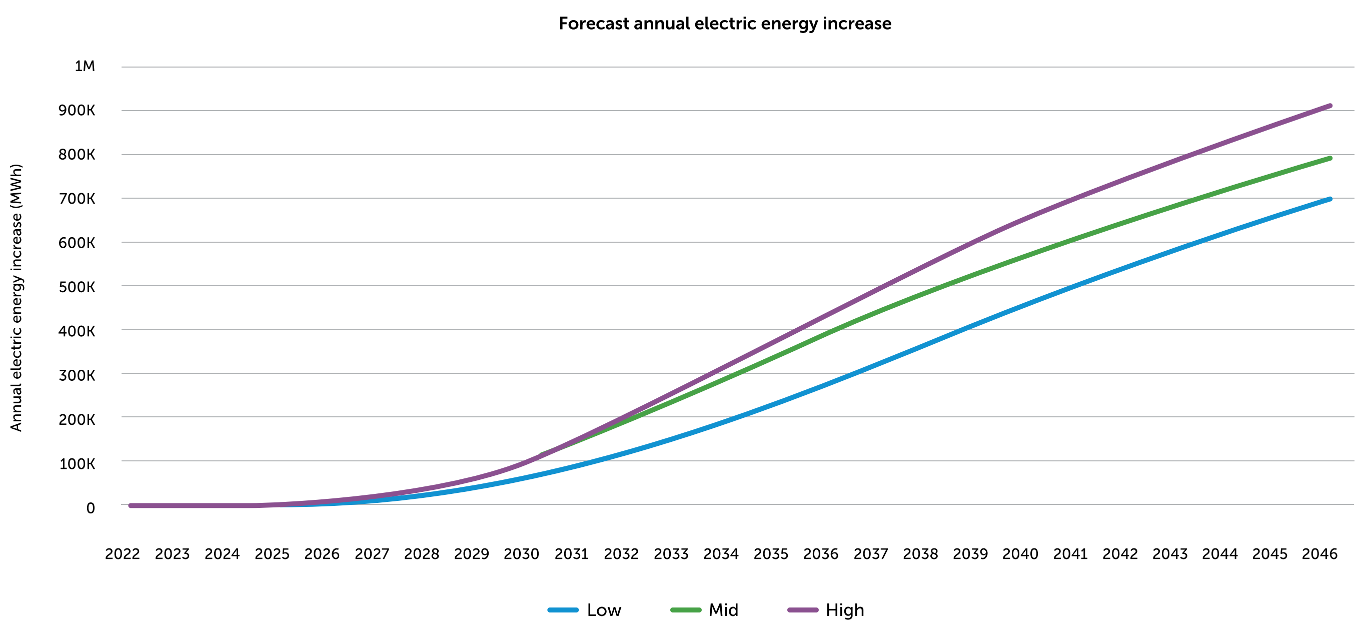



**Figure 19.** *Forecasted annual electric energy increase*

Platte River initially adopted the low forecast for its load forecast in 2022. However, it now appears the medium forecast best reflects recent changes observed in the market. These include increasing availability of federal and state tax incentives, along with the increasing acceptance of heat pump technology by local HVAC contractors.

### 5.3.3.2 Transportation

Transportation electrification refers to the shift from vehicles with internal combustion engines powered predominantly by fossil fuels (gasoline and diesel) to vehicles powered by batteries charged from the electric grid. Transportation electrification reduces dependence on fossil fuels and reduces emissions from burning fossil fuels, including greenhouse gases. Transportation electrification is driving challenges and opportunities for vehicle owners and operators; businesses involved in the sales, service and fueling of vehicles; and for electric utilities.

**Transportation electrification forecast study results.** The DER Study evaluated the adoption of EVs in the following categories: light-duty vehicles (including personal vehicles and commercial fleets), medium-duty-vehicles, heavy-duty vehicles and buses. Three growth scenarios were considered—low, medium and high—based on varying levels of policy interventions; technology availability and cost declines; and market factors (for example, electric rates, fuel prices). Utility rebates were not evaluated. Table 4 summarizes the driving factors for each scenario considered in the study.

| Parameter | Low scenario | Medium scenario | High scenario |
|---|---|---|---|
| **Policy/program interventions** | | | |
| Public charging infrastructure expansion | Limited<br><br>Planned investments + current growth trajectory | Moderate<br><br>Planned investments + accelerated growth trajectory aligned with Colorado National EV Infrastructure Formula Program (NEVI[10]) | Significant<br><br>Expanded infrastructure to ensure adoption is not constrained |
| Vehicle incentives | Current federal and state EV incentives, phase out prematurely in 2028 and 2026, respectively | Current federal and state EV incentives, phased out as currently planned in 2032 and 2028, respectively | Increased incentives and extended beyond currently planned in 2035 and 2030, respectively |
| Existing building charging infrastructure retrofits | Limited<br>15% of multi-unit buildings with access to charging by 2035 | Moderate<br><br>40% of multi-unit buildings with access to charging by 2035 | Significant<br><br>90% of multi-unit buildings with access to charging by 2035 |
| Zero-emission vehicle mandates | None | None | Stringent<br><br>100% by 2035 |
| **Technology factors** | | | |
| Battery costs | Limited cost declines | Moderate cost declines | Aggressive cost declines |
| EV model availability | Limited availability | Moderate availability | High availability |
| **Market factors** | | | |
| Vehicle sale | Maintain historical trends | | |
| Fuel prices | Limited escalation | Moderate escalation | Rapid escalation |

**Table 4.** *Primary drivers for transportation electrification*

Figures 20, 21 and 22 depict the anticipated adoption for the three scenarios in terms of number of vehicles, annual energy and summer peak demand.

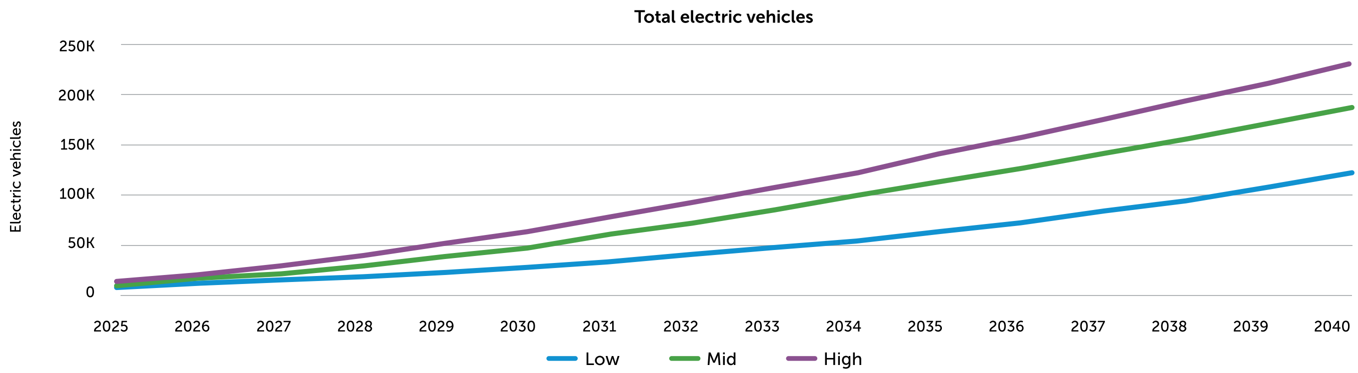



**Figure 20.** *Total electric vehicles*

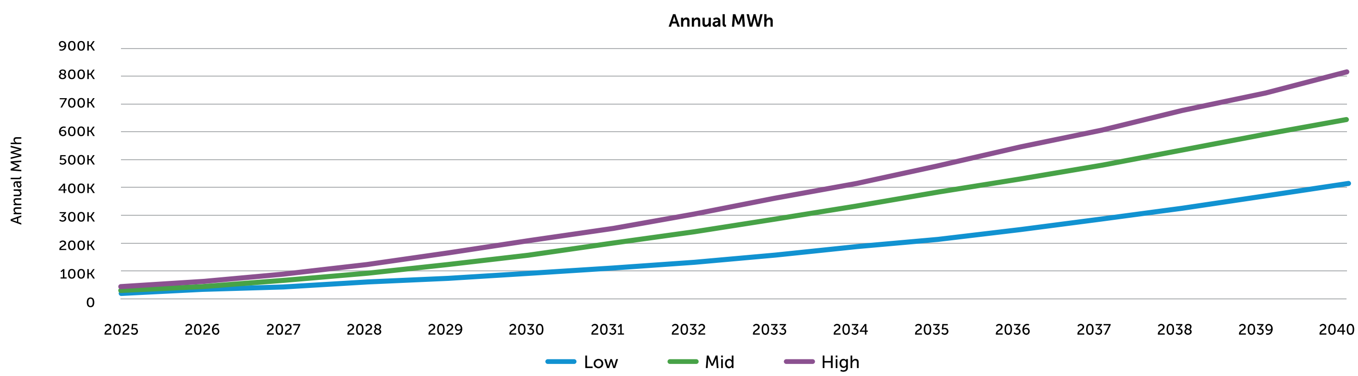



**Figure 21.** *Annual MWh*

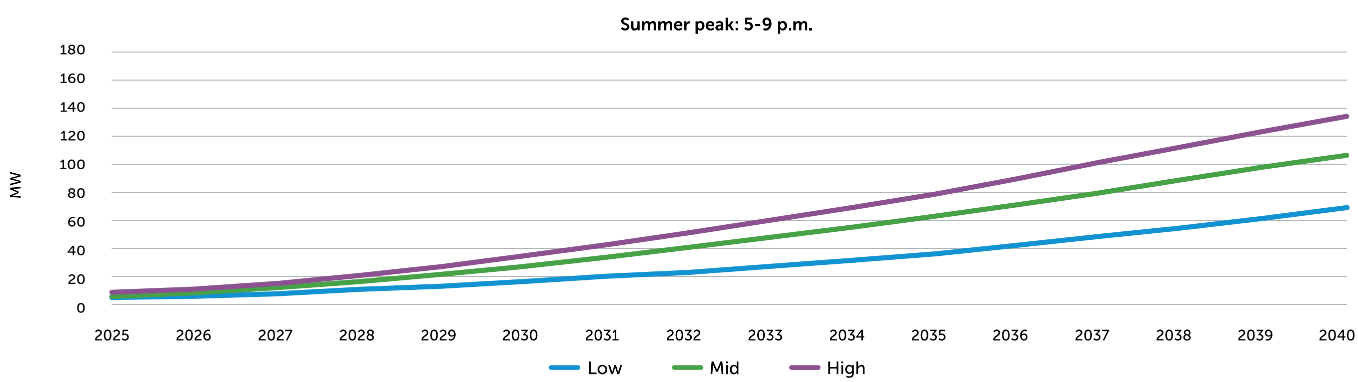



**Figure 22.** *Summer peak: 5-9 p.m.*

[10] National Electric Vehicle Infrastructure Formula Program (NEVI) is a federal grant program established under the Infrastructure Investment and Jobs act to provide states with funding to expand availability of EV fast charging infrastructure on transportation corridors.

Note that the summer peak demands are based on a diverse set of EV charging profiles (home charging, workplace charging, public charging, commercial fleet charging). These profiles assume some customers will respond to time-of-use pricing, where available. Winter peak demand effects are expected to be about 70% higher than summer peak due to the additional use of electricity in EVs to provide heat in the occupant compartment and to the batteries.

In all three growth scenarios the forecasted growth in EV adoption is poised to escalate significantly during the study period of 2023-2043.

**Monitoring and forecasting EV adoption.** As of the end of 2022, Platte River's owner communities witnessed a notable surge in the adoption of EVs. The number of estimated registered EVs within the communities at the end of 2022 was around 2,900. Throughout 2023 EV adoption has seen a steady increase, with an estimated 4,000 EVs by the end of the year, slightly under the previous forecast of 4,500. This growth within the owner communities follows closely with the Colorado state trend of a 3% growth each month, or 43% annually, in new EV registration.

The DER Study evaluated a range of adoption scenarios to inform the load forecast used for resource planning. Platte River has chosen the medium forecast, approximately 48,000 EVs by the end of 2030, which represents 42% compound annual growth from current levels. Adoption will continue to be monitored and adjustments will be made to the forecast as more data becomes available.

### 5.3.4 Transitioning Efficiency Works programs to distributed energy solutions

The Efficiency Works program offerings through Platte River's distributed energy solutions department are shifting focus to meet the customer needs through additional product education, energy advisory services and repurposing incentives to business and home upgrades that support future load flexibility. A few examples of this transition include:

- Supporting building electrification upgrades that can provide future flexibility or load control throughout the year (not just a summer peak reduction of air conditioner loads).
- Incentivizing public EV charger infrastructure to provide more charging locations for EV drivers throughout the day to accommodate different charge control program models.
- Optimizing commercial HVAC equipment though the Building Tune-up program that will provide an eventual path for advanced system automation control installations and ongoing system performance visibility.

A variety of new customer program offerings have been developed and launched in recent years to support this transition as described in sections below.

## 5.3.5 New customer programs to address future electrification requirements

### 5.3.5.1 Building electrification activities

In 2023, the Efficiency Works programs continued to support owner community initiatives and began shifting to include multiple building electrification measures. These measures mostly focused on heating and cooling equipment within residential properties while leveraging the existing energy efficiency contractor networks. The initial building electrification programming is focused on the following areas to support customers as they decarbonize their homes and business:

- Retrofitting existing residential properties
- Educating residential and commercial customers on effective ways to use their energy with building electrification upgrades
- Providing incentives to the income qualified community sector to support building electrification initiatives
- Developing programs to support distributors selling building electrification equipment in the commercial HVAC sector
- Engaging and training local contractors about the benefits of building electrification upgrades

The shift in building electrification programming also aligns with possible incentives offered through the Inflation Reduction Act and state tax credits. As interest in building electrification continues to grow, customer programs will encourage energy efficiency upgrades like building envelope improvements. In combination with the building electrification upgrades, these improvements will allow for the potential to call on demand response activities for longer durations in the future.

## Including income-qualified communities in the energy transition

For several years, Platte River has offered various programs to support income-qualified customers. In 2021, the Efficiency Works Business team launched the **Community Efficiency Grant** to provide additional financial support for energy upgrades in businesses and multifamily properties serving the income-qualified community. This effort has increased the number of participating entities **eight-fold** on an annual basis, resulting in 103 upgrades, saving an estimated $385,000 annually on the businesses' electric costs through the investment of nearly $2.1 million of the Efficiency Work Business programs. The Community Efficiency Grant is expanding eligibility in 2024 to more entities that serve the community.

In addition, Efficiency Works has partnered with Energy Outreach Colorado (EOC) since 2016 to provide free energy advising and upgrades to eligible participants. In 2023, Efficiency Works revamped the partnership structure and services available, resulting in significant positive impacts for the residential income-qualified segment. The offerings have shifted focus to actively engage with participants on more significant home upgrades including energy efficiency and building electrification. According to the EOC, this partnership has grown to be one of the most well-funded income-qualified programs and has the strongest participation impact goals in the state of Colorado. In 2023, investments of nearly $1 million have been made to support the income-qualified residential upgrades in our communities and this level of annual investment is expected to continue.

## 5.3.5.2 Transportation electrification activities

Platte River supports customers on their transportation electrification journey as they evaluate options and consider adopting EVs. This support starts with information. Platte River and the owner communities offer information on EVs through Efficiency Works.

In 2022, Platte River launched an interactive EV shopper guide website. The website includes information on currently available EVs, including cost, performance specifications and available incentives. It also includes a calculator that allows visitors to compare the total cost of ownership of EVs in comparison with each other and compared with conventional vehicles. In 2023, the website was expanded to offer EV Fleet Planning as a calculator tool for local fleet operators to develop plans to calculate the costs of fleet transitions. In 2024, expansion in the EV space will continue to support commercial customers with additional technical services to plan for EV fleet transitions and work closely with the distribution utilities on potential service upgrades and interconnection requirements.

Platte River's commitment to advancing EV infrastructure is exemplified by the 2023 initiative offering one of the highest incentives in Colorado - $5,000 per public charging port. This incentive aims to encourage local businesses and multifamily properties to host public chargers by offsetting some of the installation cost. Promoting more public charging options and making EV charging more available and visible are intended to reduce "range anxiety" among EV drivers and potential EV drivers.

#### 5.3.5.3 Commercial HVAC system optimization activities

In 2021, Efficiency Works relaunched an improved Building Tune-up program focusing on supporting commercial customers to optimize more complex systems. The program is one of the few in the nation that focuses on upgrades and services ranging from enhanced maintenance practices to complex retrocommissioning. In its current form, the programming engages with large commercial and industrial customers to optimize complex building automation systems and local HVAC contractors performing ongoing maintenance services, and engages many small and medium commercial properties in the owner communities.

Since the relaunch, the program has increased energy savings at commercial properties from an annual average of four participants to over 50. The program has also increased the number of properties participating through increased engagement of local contractors in the HVAC industry. Program staff are currently evaluating options to expand services into monitoring-based commissioning and installing advanced rooftop unit controls during routine maintenance visits. Both expansion options will provide pathways for commercial customers to participate in a future VPP, providing additional energy consumption flexibility within the system.

### 5.3.6 Distributed generation and distributed energy storage

Distributed generation refers to electric generation sources, typically solar facilities, located near the point of use, within customer premises or on the distribution system. Similarly, distributed storage refers to energy storage, typically battery storage, located near the point of use, within customer premises or on the distribution system. Distributed generation and distributed storage are considered together in this section due to the synergy between them.

From Platte River's perspective, storage is essential to achieving a noncarbon electric system because it helps align variable renewable generation, like wind and solar, with load. It does this by storing surplus energy when wind and solar generation exceed load and by discharging storage when wind and solar output drop below load. Similarly, from a customer's perspective, distributed storage paired with distributed solar generation helps the customer make use of more of their on-site generation to serve their own load. This reduces the energy they would otherwise export to the grid and later repurchase from the grid when solar production does not align with their use.

#### 5.3.6.1 Distributed generation solar and distributed storage forecast study results

The DER Study evaluated the adoption of distributed generation solar and distributed storage. The solar adoption forecast model considered historical rates of adoption and evaluated future adoption based on several parameters that varied across four scenarios. Some solar was assumed to be adopted alone, some was assumed to be adopted with distributed storage and some distributed storage was assumed to be adopted alone. Table 5 summarizes the driving factors for each scenario considered in the study.

| Parameter | Low scenario | Medium scenario | Medium export-rate scenario | High scenario |
|---|---|---|---|---|
| **Policy/program interventions** | | | | |
| Solar and storage incentives | Federal ITC (solar tax credit) benefits phased out early (2028).<br><br>No owner community incentives. | Federal ITC, phased out on schedule (2035)<br><br>Current Fort Collins incentives, phased out 2028 | | Federal ITC extended to 2040.<br><br>Fort Collins incentives adopted by all owner communities. |
| Codes and standards | No mandates | All new buildings must have solar beginning 2030. A gradual increase is assumed 2024 – 2030. | | All newly constructed buildings must have solar beginning in 2024 (commercial) and 2027 (residential) |
| Retail net energy metering (NEM) and export compensation | Current NEM and export compensation (Fort Collins time of use and other owner communities' flat rates) | New NEM:<br><br>All communities adopt time of use (TOU) rates and export compensation, summer on-peak 5 – 9 p.m. Non-TOU (commercial) has export rates 5% less than retail | New NEM with exports valued at forecasted wholesale energy market rates | New NEM:<br><br>All communities adopt TOU rates and export compensation, summer on-peak 5 – 9 p.m. Non-TOU (commercial) has export rates 5% less than retail |
| Incentive for storage participation in VPP | None | $150/kW-yr. | | $216/kW-yr. |
| Storage adoption relative to solar | 10% of solar includes storage | 30% of solar includes storage | 50% of solar includes storage | 30% of solar includes storage |
| **Technology factors** | | | | |
| Distributed solar cost | Limited cost decline (historical regional cost + future NREL solar cost decline) | Moderate cost decline (historical regional cost + future NREL solar cost decline) | | Aggressive cost declines (historical regional cost + future NREL solar cost decline) |
| Distributed storage cost | Limited NREL storage cost decline | Moderate NREL storage cost decline | | Aggressive NREL storage cost decline |

**Table 5.** *Adoption of distributed generation – solar and storage*

The DER Study considered a range of assumptions. First, the DER Study assessed the impact of federal investment tax credits, with the assumption ranging from early phaseout, in 2028, compared to scheduled phaseout, in 2035, and extended phaseout in 2040. Owner community incentives were also considered, ranging from none to Fort Collins's current incentives, to adoption of Fort Collins' incentives by the other three owner communities. In all cases, the incentives were assumed to phase out in 2028, coinciding with the significant increase in Platte River's noncarbon portfolio. The study evaluated new building standards ranging from no solar requirement to increasingly stringent requirements for new construction to include solar.

The study also considered the effect of retail rates, and specifically net energy metering (NEM), on distributed generation solar and distributed storage adoption. NEM refers to the financial compensation customers with solar (and increasingly customers with solar and distributed storage) can receive due to both reduced purchases of electricity from their retail electricity provider and due to exporting excess solar and distributed storage output to the grid whenever solar and storage produce more energy than the customer consumes.

The study evaluated a range of possible NEM rates. The **low scenario** assumed existing NEM rates apply. This includes Fort Collins's existing time-of-use rate, which charges higher rates during on-peak periods (weekdays, 2 to 7 p.m. during summer months and 5 to 9 p.m. in other months) and lower rates all other hours. Exported energy is credited on the same schedule, but at rates that are 10 to 20% lower. The other owner communities largely have time-invariant rates and compensate exports at or close to the retail rate.

The **medium and high scenarios** assumed all owner communities adopt a rate structure like Fort Collins and that the summer on-peak period shifts later in the day, to 5 to 9 p.m., for all communities. This is due to anticipated high adoption of solar by customers and by Platte River. This results in reduced demand for energy and ample supply when solar energy is available, followed by higher demand and reduced supply as the sun sets and solar output diminishes and then stops. This will lead to higher energy costs as the sun sets and after the sun is down.

The **medium export-rate scenario** assumed the financial value of solar will erode due to higher solar adoption by customers, Platte River and other utilities in the region; low energy prices when solar is plentiful, followed by high prices when solar is absent. Achieving greater value from the solar energy will require that it be shifted in time, from peak solar hours to hours just after the sun sets, which can be achieved through increased deployment and use of energy storage (whether distributed or utility-scale). Modifying the retail rate to compensate exported solar at the wholesale rate will better reflect the value solar alone brings to the system, and at the same time provide value to customers who adopt and use distributed storage to reduce exports and use more solar energy at the home or business.

The study also assessed the adoption of distributed storage. This is projected to be driven by rates and the rate structure as well as on incentives that could be paid to customers to adopt distributed storage and to enroll distributed storage in a VPP for Platte River to dispatch. The combined impact of changes to net energy metering, export compensation and

VPP incentives, coupled with declines in storage costs, are projected to drive higher adoption of storage with solar – increasing from the low scenario (in which 10% of solar was assumed to include storage) to 50% for the medium-export scenario.

Platte River also constructed a fifth scenario, which starts with the medium scenario and then shifts over a period of about 10 years to the medium export-rate scenario.

Figures 23 and 24 illustrate the forecasted adoption of distributed solar and storage, respectively.

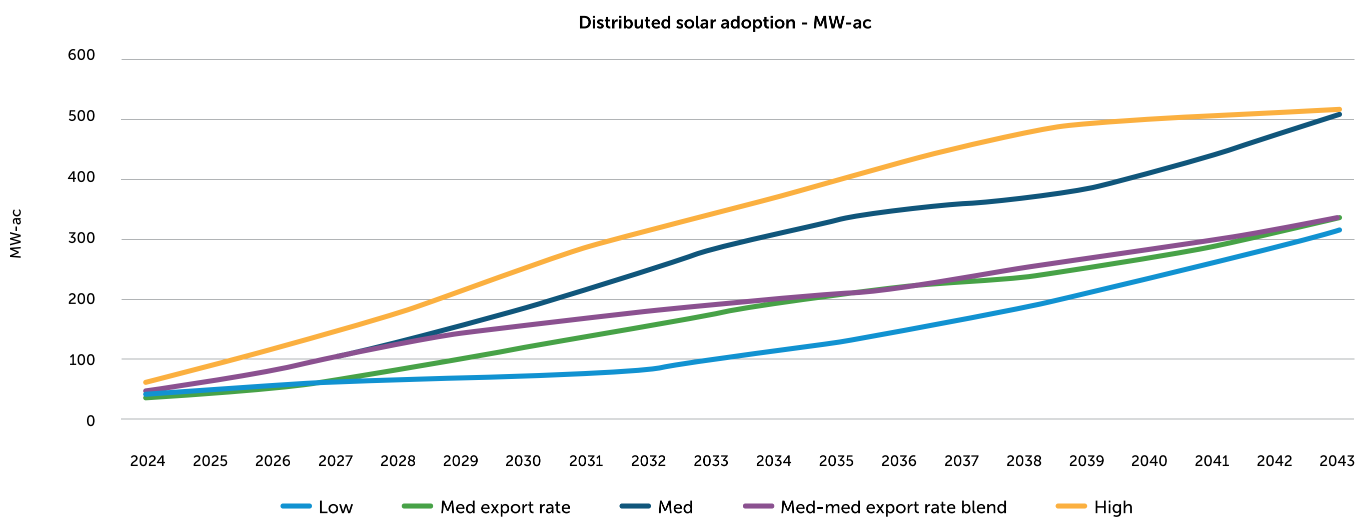



**Figure 23.** *Distributed solar adoption - MW-ac*

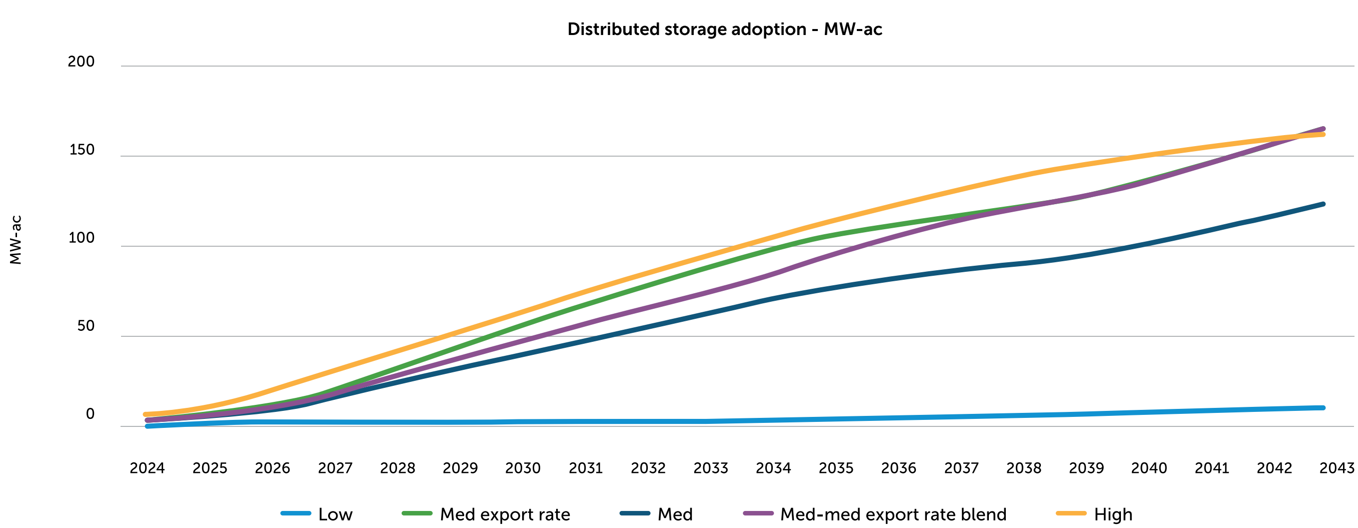



**Figure 24.** *Distributed storage adoption - MW-ac*

**Monitoring and forecasting distributed generation solar and distributed storage adoption.** The rise of distributed generation within the owner communities has primarily been driven by individual customers adopting rooftop solar power. Solar energy constitutes around 94% of the existing distributed generation capacity. The remaining capacity is divided among wind (0.02%), cogeneration (4.1%) and hydropower (1%).

Figure 25 illustrates the growth of distributed solar capacity within Platte River's network, fueled by available federal and local incentives, coupled with customers' economics and drive to reduce carbon emissions from electricity generation. As of the end of 2022, estimated distributed solar within Platte River's owner communities totaled 36.3 MW (AC), with 63% from residential solar, 17% from commercial solar, and 20% owned or procured by Platte River or the owner communities.

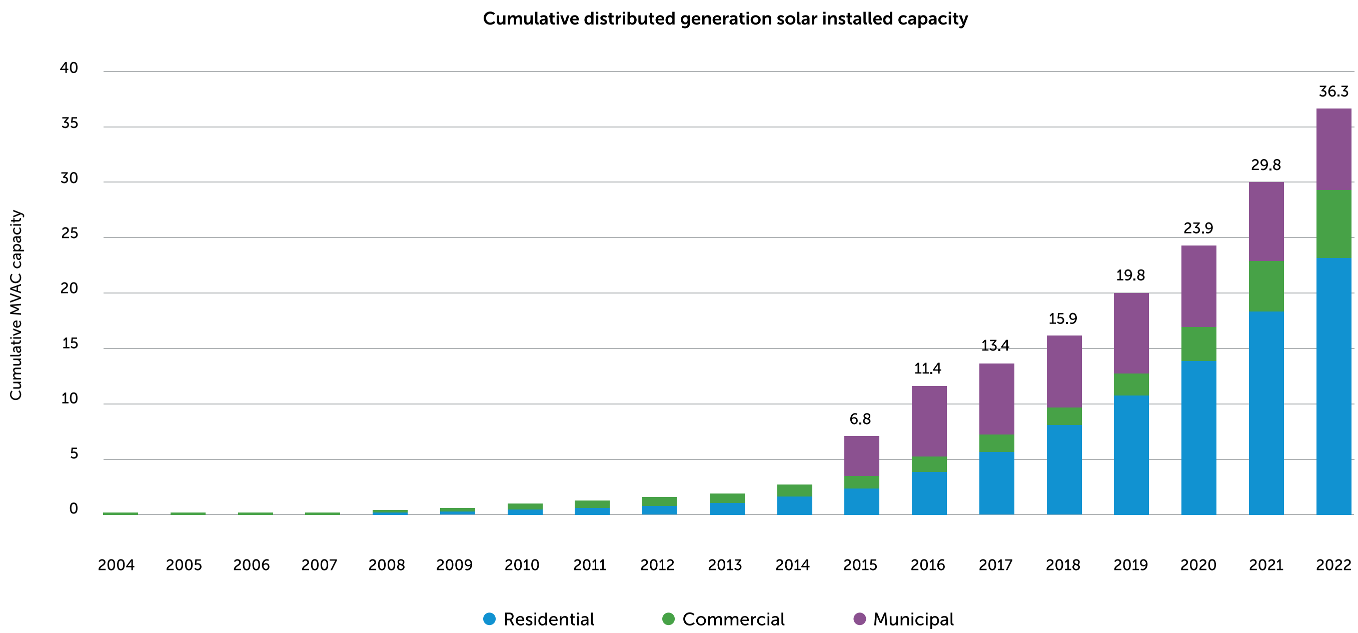



**Figure 25.** *Cumulative distributed generation solar installed capacity*

Between 2017 and 2022, there has been a notable increase in distributed storage deployment, raising the total capacity to about 1.2 MW in the owner communities. This comprises about 175 systems, averaging a discharge rate of about 7 kW per system. Each year since 2017, there has been an increase in distributed storage system interconnections, with the highest number of installations in 2022. This significant rise highlights the widespread adoption of storage solutions, particularly battery storage, as a versatile tool for providing backup energy and enhancing the operational efficiency of distributed solar systems.

The DER Study evaluated a range of distributed generation solar and distributed storage adoption scenarios to inform the load forecast used for resource planning and to inform DER planning.

Platte River has chosen the blend of the medium and medium-export-rate forecasts. This combination of scenarios represents a gradual change in NEM rates that improves the financial benefit of adopting distributed storage with distributed generation solar. This forecast indicates approximately 155 MW distributed generation solar and 47 MW distributed storage by the end of 2030. This represents 20% annual growth in installed solar capacity and 48% annual growth in storage capacity from current levels. Adoption will continue to be monitored and adjustments will be made to the forecast as more data becomes available.

## 5.3.7 Flexible DERs and the virtual power plant

As described in previous sections, a VPP is an aggregation of flexible DERs that can be dispatched to support electric system reliability, financial benefits and individual customer benefits. As the name suggests, the VPP can act like a power plant, but it is different in that it is created by thousands of DER devices operating across the electric system. They act in concert, enabled by communication, data collection and management, control and optimization technology.

### 5.3.7.1 Flexible DER and VPP forecast study results

The DER Study included an assessment of flexible DER that could provide VPP capacity. VPP capacity was evaluated using a multi-step approach that considered the technical, economic and achievable potential of flexible DER technology combined with utility program approaches:

- Technical potential assesses the quantity of flexible DER capacity that theoretically exists in the owner community service territory and how it is expected to grow over time.
- Economic potential considers how much of the technical potential is economic compared to other utility resource options. The study relied on the total resource cost test framework, which compares the marginal costs of a VPP resource for Platte River, the owner communities and their customers to the marginal cost of utility resources.
    - o The cost of utility resources included hourly energy costs based on forecasted market energy prices, carbon tax, capacity costs based on four-hour storage and distribution capacity costs based on owner community estimates.
    - o The cost of achieving VPP potential included utility program administration costs (excluding incentives) and customer DER technology costs.
    - o The cost of achieving VPP potential did not include the cost to the utility of VPP-enabling technology and systems. The need for enabling technology and systems is unaffected by which flexible DER programs Platte River and the owner communities offer.
- Achievable potential considers how much of the economic potential can be realized as a dispatchable VPP capacity at the time of system need and considering customer enrollment rates in VPP program.

The potential study assessed achievable capacity at times of high "net load." This was defined as the load that remains after deducting wind, solar and hydropower. Figure 26 illustrates what this might look like in 2030. Note that while only one day is shown, there are multiple days each summer that would have a similar, though slightly smaller, peak net load. As a result, flexible DER capacity is required many hours throughout the summer. As electrification increases winter loads at a more rapid rate than summer loads, the need for winter dispatchable capacity will grow as well.

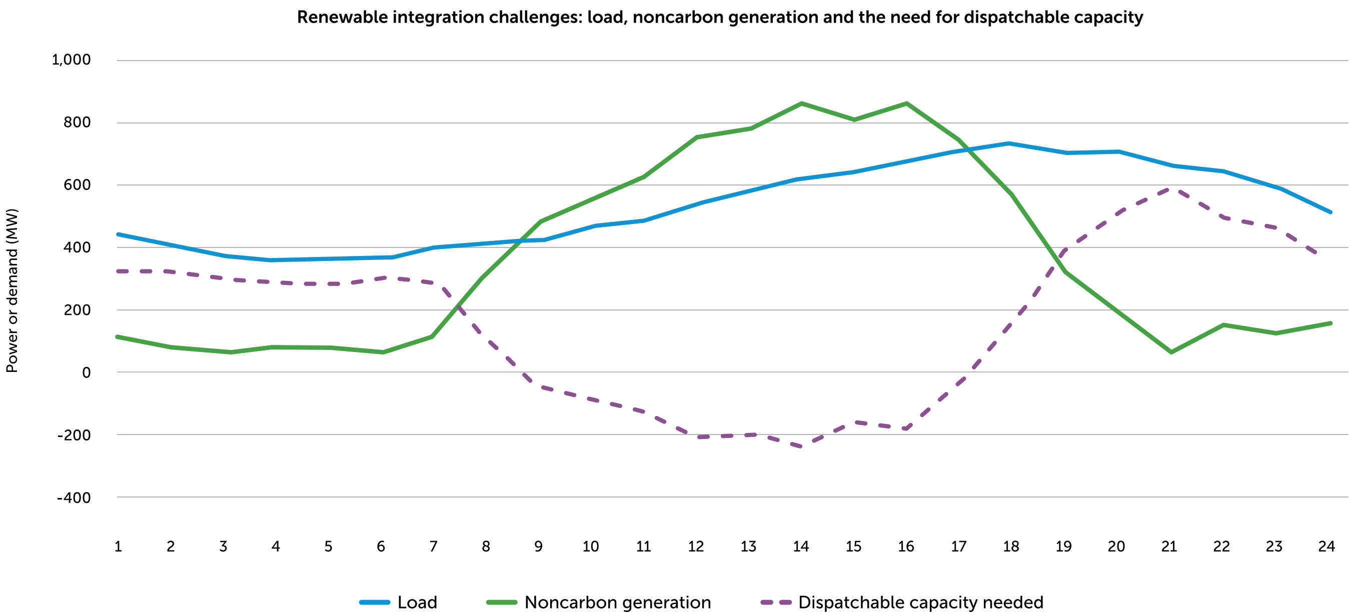



**Figure 26.** *Renewable integration challenges: load, noncarbon generation and the need for dispatchable capacity*

The DER Study assessed a variety of factors that could drive varying levels of achievable VPP capacity. These were combined in four scenarios as shown in Table 6.

| Parameter | Low scenario | Medium scenario | Medium export-rate scenario | High scenario |
|---|---|---|---|---|
| Time-varying rates | Existing residential TOU rates in Fort Collins only (summer on-peak 2 – 7 p.m.) | New residential TOU rates in all owner communities (summer on-peak 5-9 p.m., aligning with net system peak) | New residential TOU with solar exports valued at forecasted wholesale energy market rates | New residential TOU rates in all owner communities (summer on-peak 5-9 p.m., aligning with net system peak) |
| Program marketing and incentives | Industry-standard marketing and incentives | Industry-standard marketing and incentives | Industry-standard marketing and incentives | Maximum cost-effective marketing and incentives |
| Efficiency scenario | Low | Low | Low | High |
| Electric vehicle scenario | Low | Medium | Medium | High |
| DS solar and storage scenario | Low | Medium | Medium export-rate | High |

**Table 6.** *Primary drivers of achievable VPP capacity*

Within each scenario, various flexible DER approaches were evaluated in an interactive model to determine how they could be combined to provide a sustained reduction in the system net peak, considering the impact of time-varying rates, direct-control programs and each DER's operating characteristics, as summarized in Table 7.

| Measure group | Measure sub-group | Characteristics | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Curtail-ment potential | Event duration (hours) | Pre-charge time | Pre-charge sizing | Rebound time | Rebound sizing (per hour) | Event frequency (per year) |
| **HVAC controls** | Smart thermostats | [75%, 33%] | Up to 2 h | 1 h | 40% | 2 h | 30% | 20 |
| **EV charging** | EV smart chargers | 100% | 4 h + | N/A | N/A | 6 h | 17% | 300+ |
| | Vehicle-to-grid | 100% | 4 h + | N/A | N/A | 6 h | 17% | 300+ |
| **Water heating** | Electric water heaters | 100% | Up to 4 h | 2 h | 17% | 4 h | 17% | 15 |
| **Other loading flexibility** | Large C&I curtailment | 25% | Up to 4 h | N/A | N/A | N/A | N/A | 15 |

**Table 7.** *Flexible DER operating characteristics – load*

| Measure group | Measure sub-group | Characteristics | | | | | |
|---|---|---|---|---|---|---|---|
| | | Size (kW) | Curtail-ment potential | Round trip efficiency | Typical event duration (hours) | Typical rebound / pre-charge time | Typical event frequency (per year) |
| **Storage** | Battery storage - residential | 3.3 | 33% | 85% | 4 h | 4 h | 300+ |
| | Battery storage – small commercial | 5 | 100% | 85% | 4 h | 4 h | 300+ |
| | Battery storage – large commercial | 50 | 100% | 85% | 4 h | 4 h | 300+ |

**Table 8.** *Flexible DER operating characteristics – storage*

- For residential, it is assumed 33% of the battery is available for flexible DER program, with the remainder used for customer resiliency.
- For commercial batteries, 100% is assumed available for flexible DER, as batteries are typically used for peak load management, and backup generators are used for resiliency.

As illustrated in tables 7 and 8, the flexibility of EVs and battery storage is apparent, with both having the ability to be dispatched on a near-daily basis, 300 times annually. This provides potential for a highly flexible, available resource that can be used to balance variable noncarbon generation. Flexibility of other DERs, such as HVAC control, large commercial and industrial curtailment and water heater control will be limited due to impacts on comfort and productivity.

Figures 27 and 28 summarize the resulting achievable capacity for each of the cases, as well as the annual costs in 2030 and 2040. Program costs are strictly incentives and program administration. They do not include VPP system costs. Growth from 2030 to 2040 was driven largely by increasing adoption of battery storage and EVs.

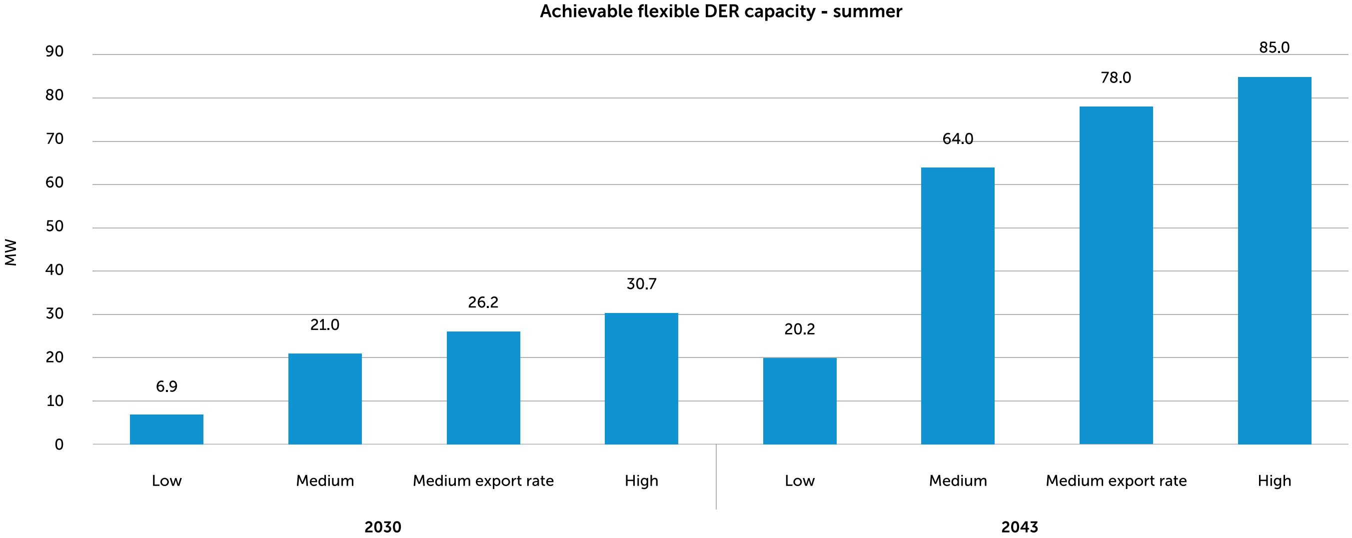



**Figure 27.** *Achievable flexible DER capacity - summer*

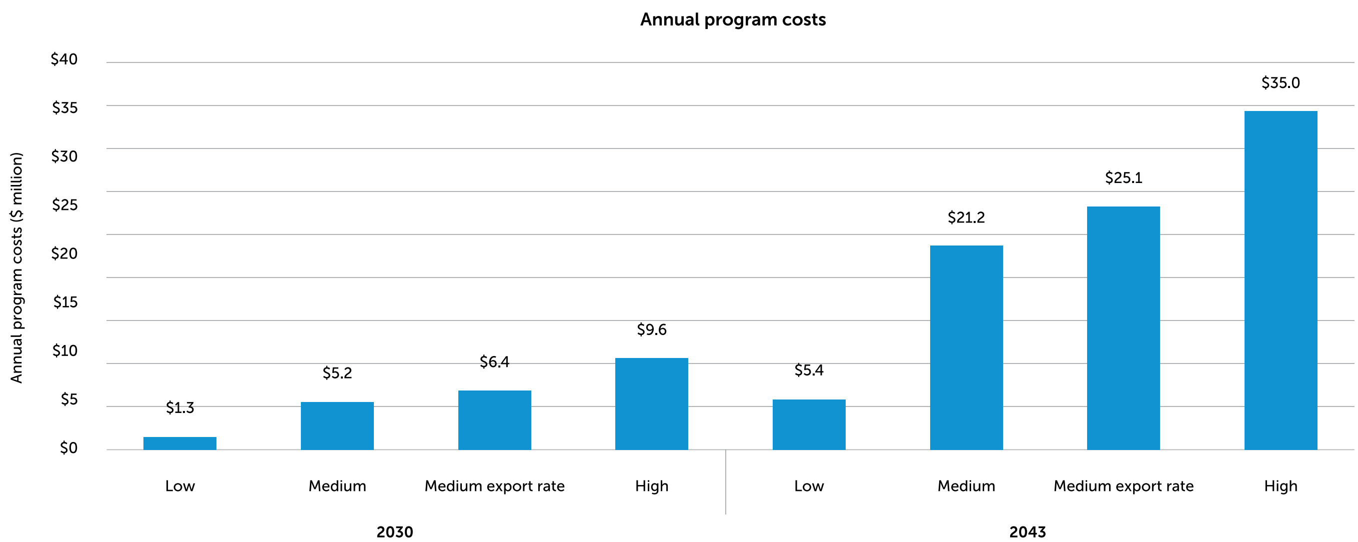



**Figure 28.** *Annual program costs*

Key takeaways from the DER Study include:

- Summer peak load reductions range from 6.9 MW to 30.7 MW across the different scenarios in 2030.
- The commercial sector is forecasted to have the greatest potential for the low scenario while the residential sector overtakes commercial in the medium and high cases, due to increasing adoption of EVs and distributed storage.
- For the residential sector, battery storage is expected to be by far the most prominent measure in all scenarios except the low one, followed by smart EV chargers and AC smart thermostats in the summer and electric resistance smart thermostats in the winter.
- The commercial demand response potential is primarily driven by large commercial and industrial opportunities, followed by battery storage and water heating.

**Develop and implement VPP customer programs.** Customers who have flexible DERs and are willing to enroll them in the VPP provide the engine for the VPP's operation. Therefore, a major focus of Platte River and the owner communities is to develop customer programs that support customer enrollment and ongoing participation.

Customer programs must support Platte River's pillars of providing reliable, environmentally responsible and financially sustainable energy, while also providing benefits to participating customers. The DER Study has identified the following opportunities for flexible DERs that can participate in the VPP:

- **Distributed storage management.** Distributed storage is expected to grow significantly, often paired with distributed generation solar.
- **EV charge management (including vehicle-to-grid when available)**. EV

adoption is expected to grow significantly, providing a large and highly flexible load for the VPP. Vehicle-to-grid is also anticipated to grow, with the potential of providing additional storage to the grid.

- **Large commercial and industrial customer custom demand response.** These customers are likely to have large and sometimes unique DER opportunities. Platte River anticipates developing custom approaches to support these projects similar to the custom, pay-for-performance incentives currently offered for efficiency improvements.

- **HVAC demand response.** HVAC demand response programs manipulate electric load for heating and cooling buildings for short periods of time, either through direct control of the heating or cooling system components (for example, compressor load-control switches) or increasingly, through wi-fi enabled thermostats ("smart thermostats").

- **Electric water heater demand response and storage.** Electric water heater demand response takes advantage of the storage that is typically integral to the water heat to allow active heating to be curtailed for brief periods.

Taken together, these customer resources are anticipated to provide a VPP capable of dispatching 32 MW of capacity by 2030 and 93 MW by 2040. To improve the availability of this capacity, Platte River anticipates enrolling more DER capacity than these values indicate. This is to account for limitations on the flexibility of DERs to consistently provide capacity during the evening peak while respecting customer restrictions on Platte River's and the owner communities' use of their flexible DERs. As a result, the enrolled capacity of customer resources may reach an estimated 71 MW by 2030 and 204 MW by 2040. As experience is gained operating the VPP, it is possible that other uses for the enrolled capacity may emerge.

In addition to the customer resources, the VPP is anticipated to include other flexible DERs developed by Platte River and the owner communities. Platte River is in developing plans for 20 MW of distribution-scale storage to be located within the owner communities. This is expected to bring the total achievable VPP capacity to about 52 MW by 2030 and 113 MW by 2040.

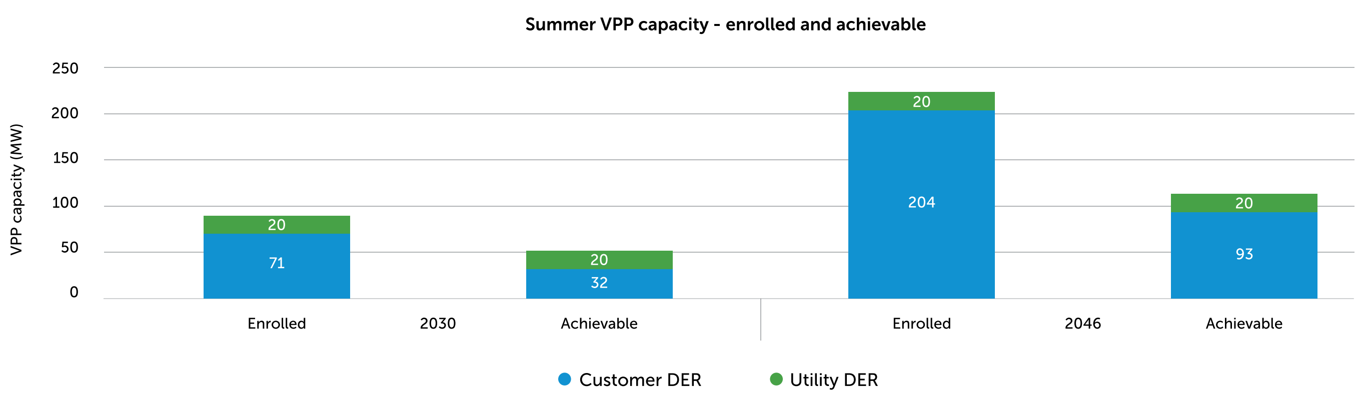
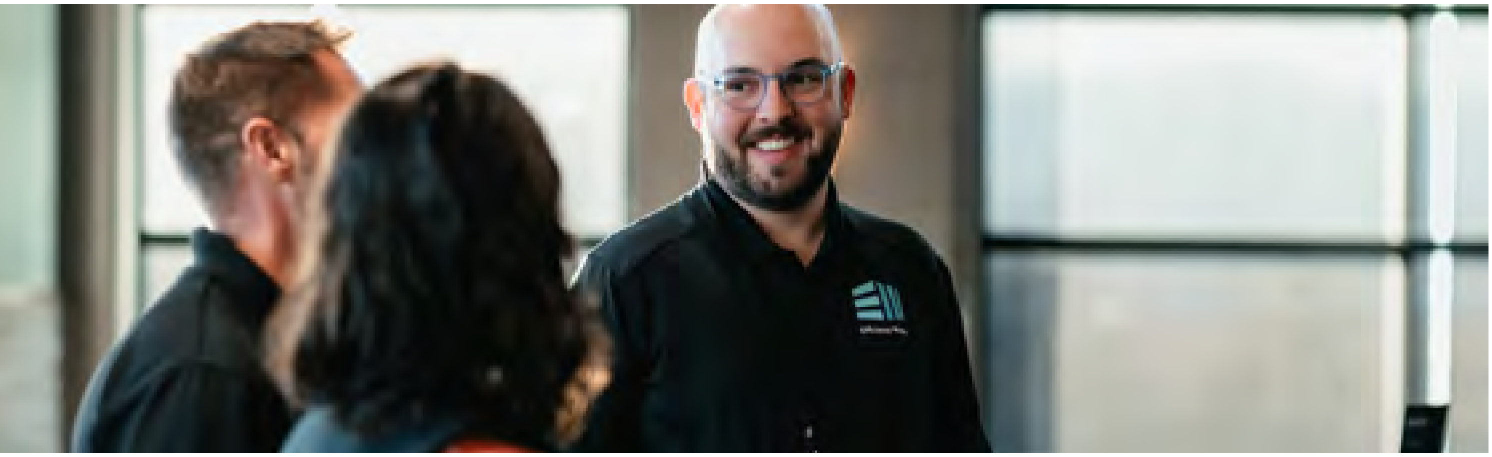



**Figure 29.** *Summer VPP capacity - enrolled and achievable*



Achieving a VPP of this magnitude requires a high level of customer participation. The enrolled capacity is projected to include 50,000 DER devices by 2030 and close to 100,000 devices by 2040, drawn from the owner communities' customer base of about 172,000 customers. To achieve this high level of participation, Platte River will collaborate with the owner communities to support customers on their DER journeys. This includes engaging customers as they evaluate their DER options and consider enrollment in the VPP. It is also expected to include providing incentives for enrollment and ongoing participation based on the system benefits their DERs can provide. In addition, Platte River and the owner communities will need to engage with the local, regional and some national market actors in the manufacturing, distribution, sales, installation, and operation of DERs.

Platte River issued an RFP in May 2024 to identify firms experienced in providing VPP customer program deployment to provide a rapid, cost-effective, and customer-focused portfolio of VPP programs.

### 5.3.8 Summary of selected scenarios for DER and VPP potential

Platte River evaluated a range of DER potential scenarios, ranging from low to high. Table 9 summarizes the scenarios selected for each type of DER and describes the reason the scenario was selected.

| DER type | Selected scenario | Description |
|---|---|---|
| Energy efficiency | Low | Low scenario is most consistent with current participation levels, even as Efficiency Works offers some of the highest efficiency incentives in the state. |
| Building electrification | Medium | Medium scenario is most consistent with observed adoption rates and with increasing local, regional and national support for electrification. |
| Transportation electrification | Medium | Medium scenario is most consistent with observed adoption rates and with increasing local, regional and national support for electrification. |
| Distributed generation and storage | Medium-medium export rate | A hybrid scenario starting with medium and shifting to medium export rate was used to reflect current adoption trends and anticipated shifts in net metering policy to favor storing excess solar rather than exporting it. |
| Virtual power plant / flexible DERs | Hybrid – see description | A hybrid scenario was defined in part by the DER adoption scenarios described above. In addition, EVs that the study assumed would respond to time-varying rates were instead reclassified as being under direct load management to provide greater responsiveness to varying system conditions. The result is that the selected VPP potential is close in magnitude to the high scenario. |

**Table 9.** *Summary and logic for selected scenarios*

## 5.4 Load forecast with DER (final) 2024-2043

Section 5.2 of this chapter covered load forecast before considering the impact of DERs. In section 5.3, we covered different DERs and saw how much energy and peak demand they contribute (like distributed solar or demand response) and require from the system (like EVs and building electrification). This section discusses the energy and peak demand contribution of each DER and the composite load forecast including the contributions from all the DERs. The composite load forecast, including energy and peak demand, was used in the Plexos model to develop a supply-side portfolio.

## 5.4.1 Energy contributions of DER

### 5.4.1.1 Distributed generation

Figure 30 shows the energy contribution from distributed generation, primarily distributed solar. This is shown as negative because it represents the reduction in customer energy needs from Platte River's supply. The bars show energy in gigawatt-hours (GWh) and the solid line shows percent reduction in total Platte River energy. By 2030, distributed generation energy is expected to reduce base energy by 6% and by the end of planning horizon in 2043, it is expected to reduce the predicted base energy by about 13%. Distributed solar produces more energy in summer and less energy in winter but these are annualized values.

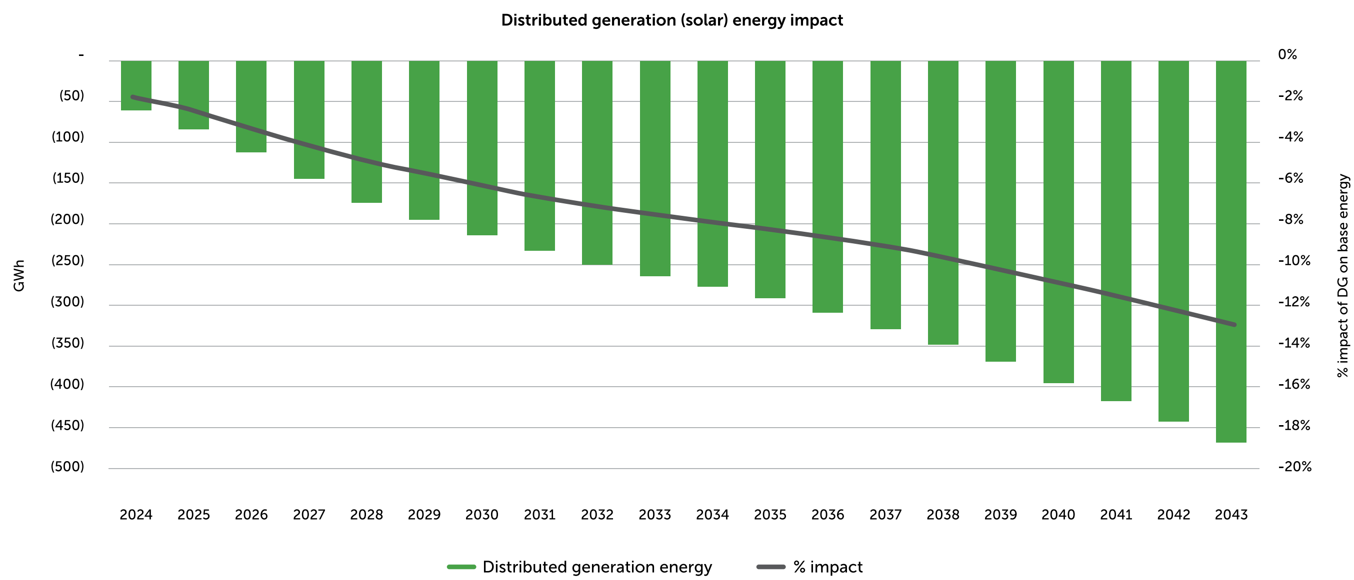



**Figure 30.** *Distributed generation (solar) energy impact*

### 5.4.1.2 Building electrification

As illustrated in Figure 31, building electrification (mostly consisting of heating load) starts from a very small level but is expected to grow rapidly in the next decade. The bars show energy in GWh and the solid line shows the percent increase in the base energy forecast. By 2030, building electrification is expected to increase base energy by 3% and by the end of the planning horizon in 2043, it is expected to add about 19% to the predicted base energy. Because it is heating load, most of the building electrification energy requirements will be in winter, but we show annual values in the chart.

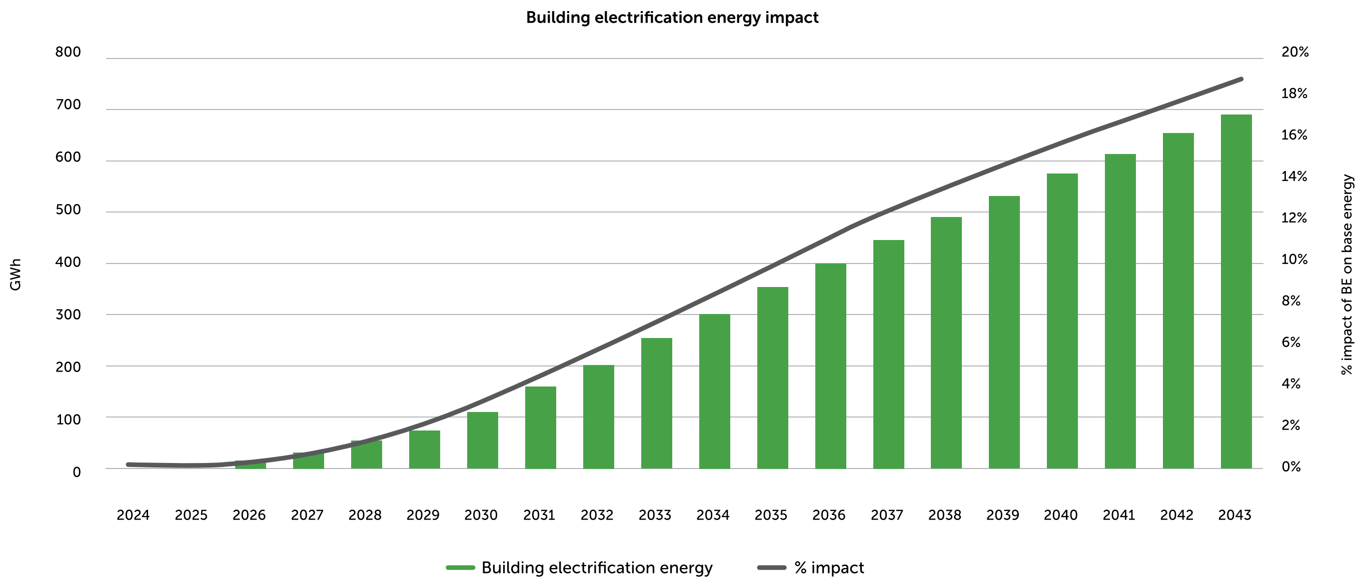



**Figure 31.** *Building electrification energy impact*

## 5.4.1.3 Electric vehicles

As illustrated in Figure 32, EV load starts from a very low level but is expected to grow rapidly in the next decade. The bars show energy in GWh and the solid line shows percent increase in the base energy forecast. By 2030, EV is expected to increase base energy by 5% and by the end of the planning horizon in 2043, it is expected to add about 23% to the predicted base energy. These are annual values. EV load is evenly distributed across the year. A portion of the EV load is flexible and exact charging time can be managed by the utility to more opportune times.

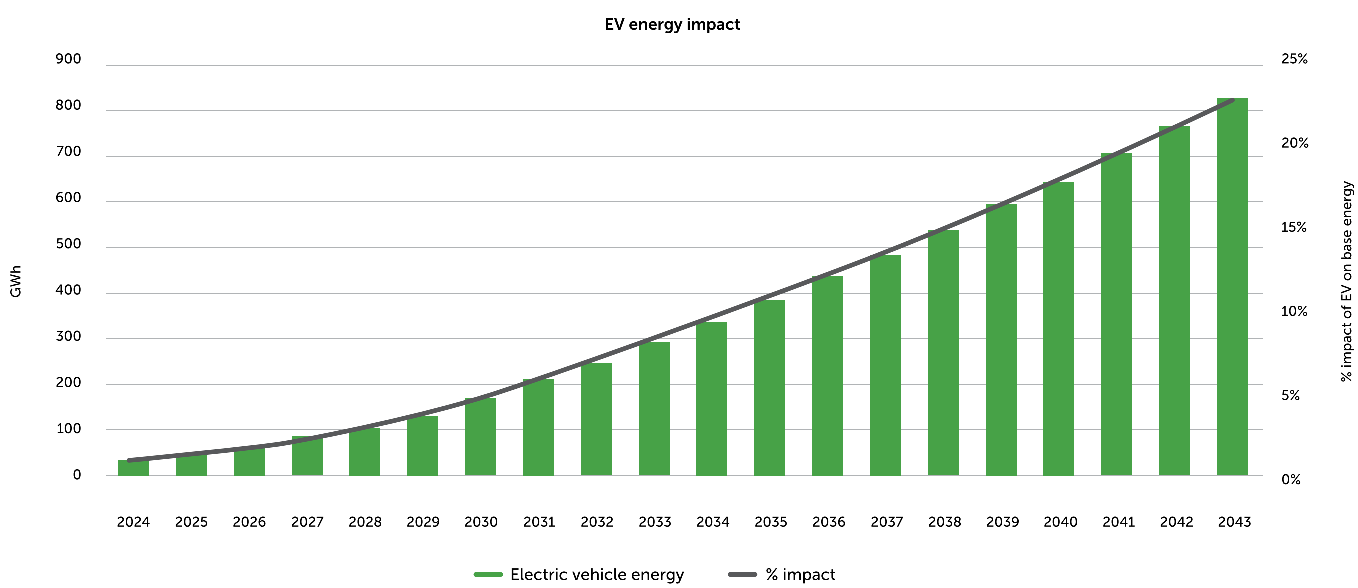



**Figure 32.** *EV energy impact*

## 5.4.2 Capacity contribution of DER

### 5.4.2.1 Distributed generation

Figure 33 shows the summer peak capacity contribution from distributed generation. This is shown as negative because this is the reduction in customer peak demand due to the rooftop solar. The bars show summer peak capacity in megawatts and the solid line shows percent reduction in total Platte River annual summer peak demand. By 2030, distributed generation is expected to reduce summer peak by 2% and by the end of planning horizon in 2043, it reduces the predicted summer peak by about 3.4%. Although the absolute megawatt addition of rooftop solar is large, its impact on the summer peak is small due to low Effective Load Carrying Capability (ELCC) value of distributed solar (like utility scale solar). Basically, the incremental contribution of solar to reduce summer peak becomes negligible to zero as more solar is added and the peak hour moves closer to the sunset.

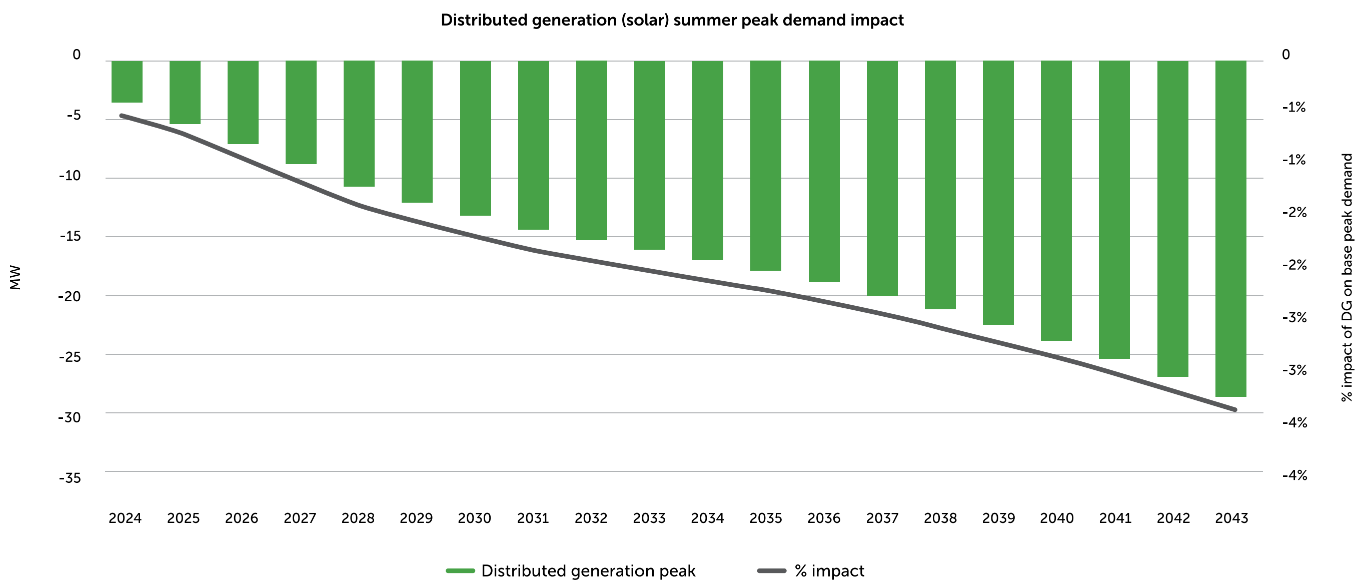



**Figure 33.** *Distributed generation (solar) summer peak demand impact*

### 5.4.2.2 Demand response

Figure 34 shows the summer peak capacity contribution from demand response or flexible resources such as home battery storage and EV charging load. This is shown as negative because it represents the reduction in overall customer peak demand. The bars show summer peak capacity in megawatts and the solid line shows percent reduction in total Platte River annual summer peak demand. By 2030, demand response is expected to reduce summer peak by 5% and by the end of planning horizon in 2043, it reduces the predicted summer peak by about 9%.

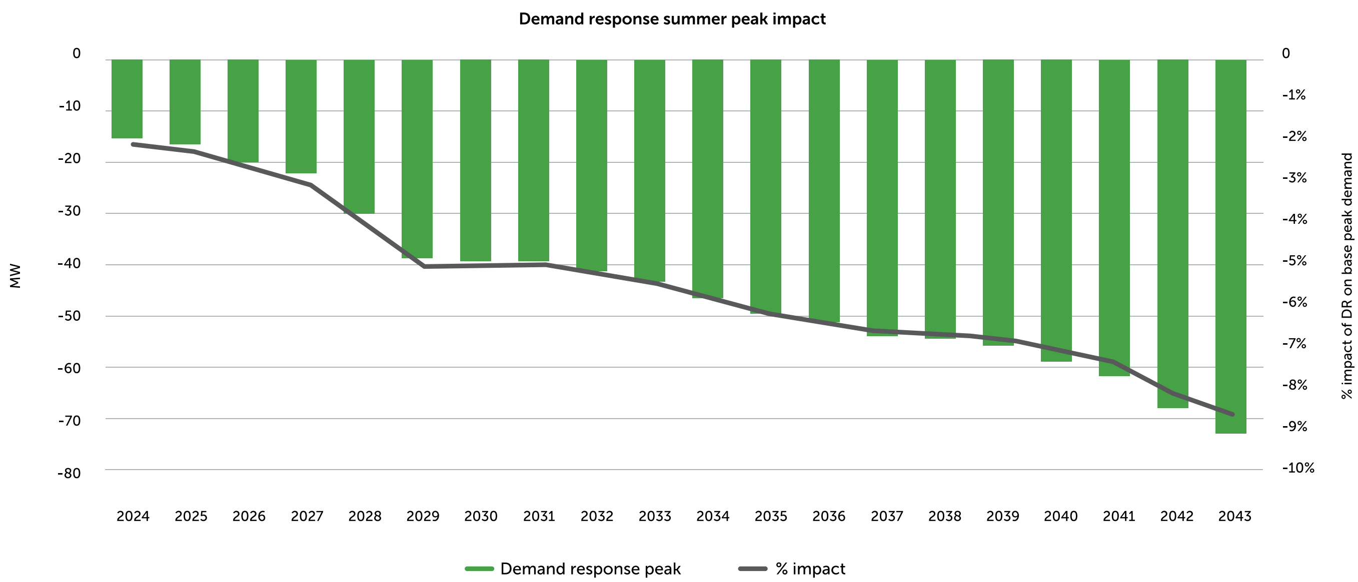



**Figure 34.** *Demand response summer peak impact*

## 5.4.2.3 Building electrification

As illustrated in Figure 35, building electrification starts from a very low level but is expected to grow rapidly in the next decade. Most building electrification contribution is from heating systems in colder months, so the impact on summer peak demand is fairly small, mainly coming from electric cooking and water heating. The bars show summer peak hour building electrification load in megawatts and the solid line shows percent increase in the base peak demand. By 2030, building electrification is expected to increase summer base peak by about 1% and by the end of the planning horizon in 2043, it adds about 3% to the predicted base summer peak demand.

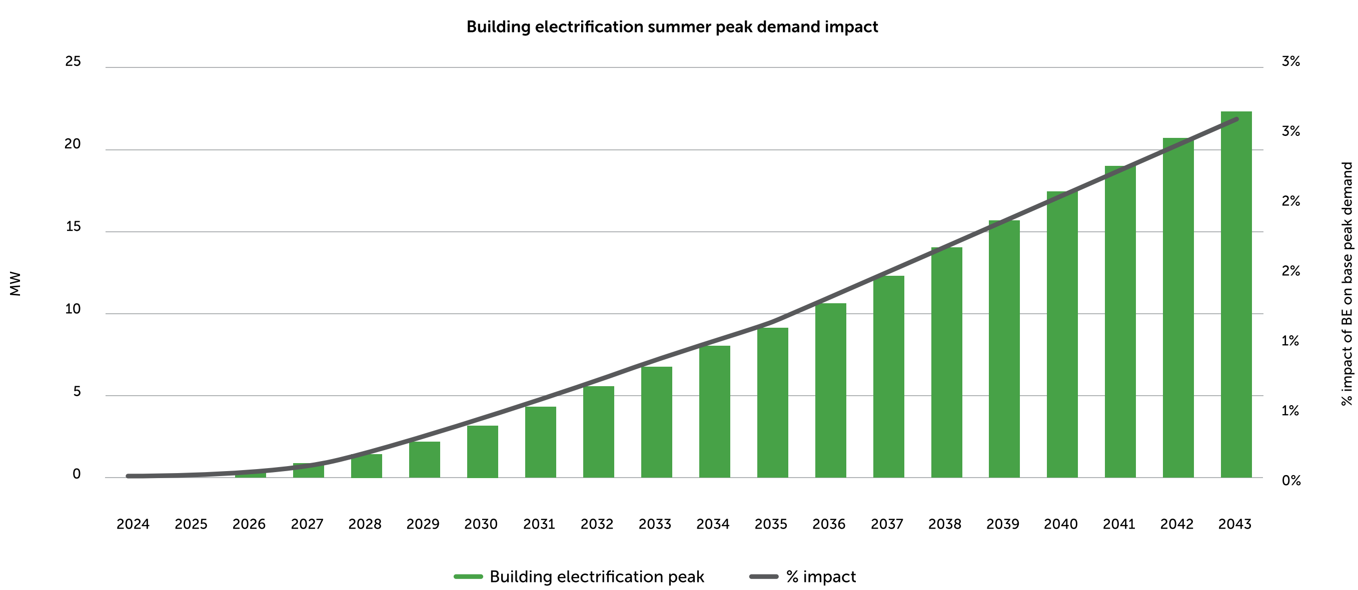



**Figure 35.** *Building electrification summer peak demand impact*

### 5.4.2.4 Electric vehicles

As illustrated in Figure 36, electric vehicle load starts from a very low level but is expected to grow rapidly in the next decade. This figure shows the portion of the EV load that is inflexible and cannot be managed or moved away from the summer peak hour. The bars show summer peak capacity in megawatts and the solid line shows percent increase in the summer base peak demand forecast. By 2030, EV is expected to increase summer base peak demand by 3% and by the end of the planning horizon in 2043, it adds about 15% to the predicted base summer peak demand. It is important to note that most EV load is flexible, and its exact charging time can be managed by the utility to lower summer peak demand. Contribution from the flexible EV charging load is not included in the chart below because we assume it will be controlled at the time of summer peak hour and moved to a later, lower-demand hour.

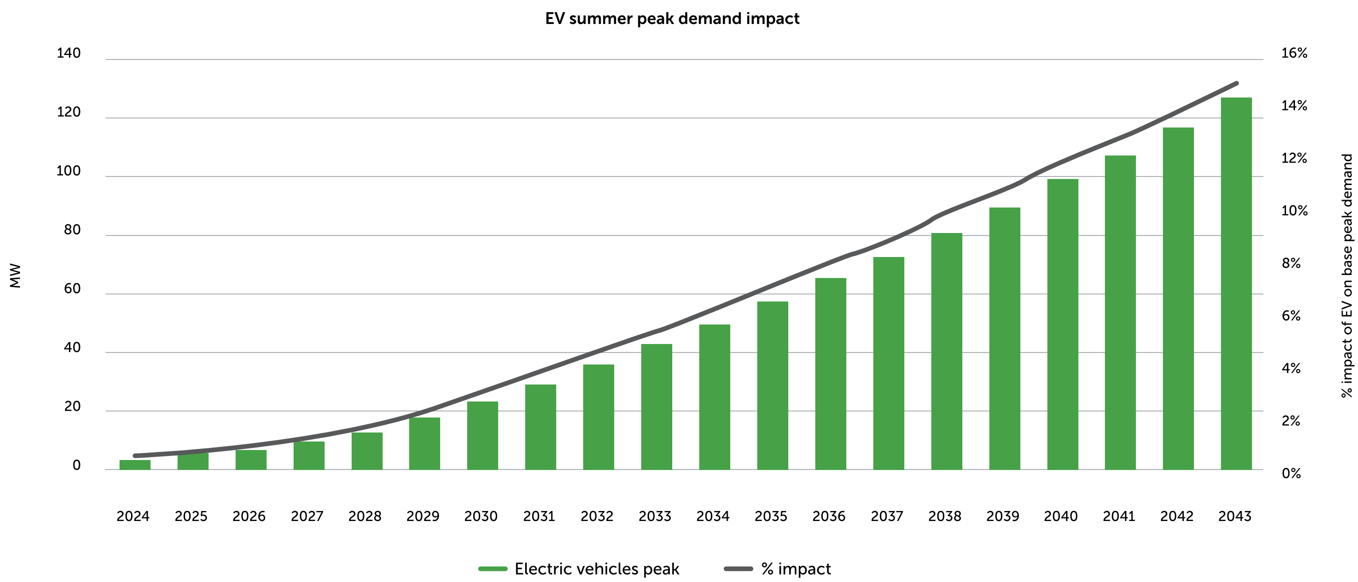



**Figure 36.** *EV summer peak demand impact*

## 5.4.3 Composite load with all DER contributions

Collectively, DERs decrease electric consumption and load growth in early years, due to the presence of distributed generation resources like rooftop solar and demand response programs, offsetting additional load created by electric vehicles and building electrification. However, as adoption of electric vehicles and building electrification increase, the additional load outpaces growth in distributed generation, resulting in higher load growth. The combined DER impact trend is similar for annual energy and summer peak demand but the percent impact varies. Figure 37 shows composite annual energy requirements and the combined percent impact of DERs.

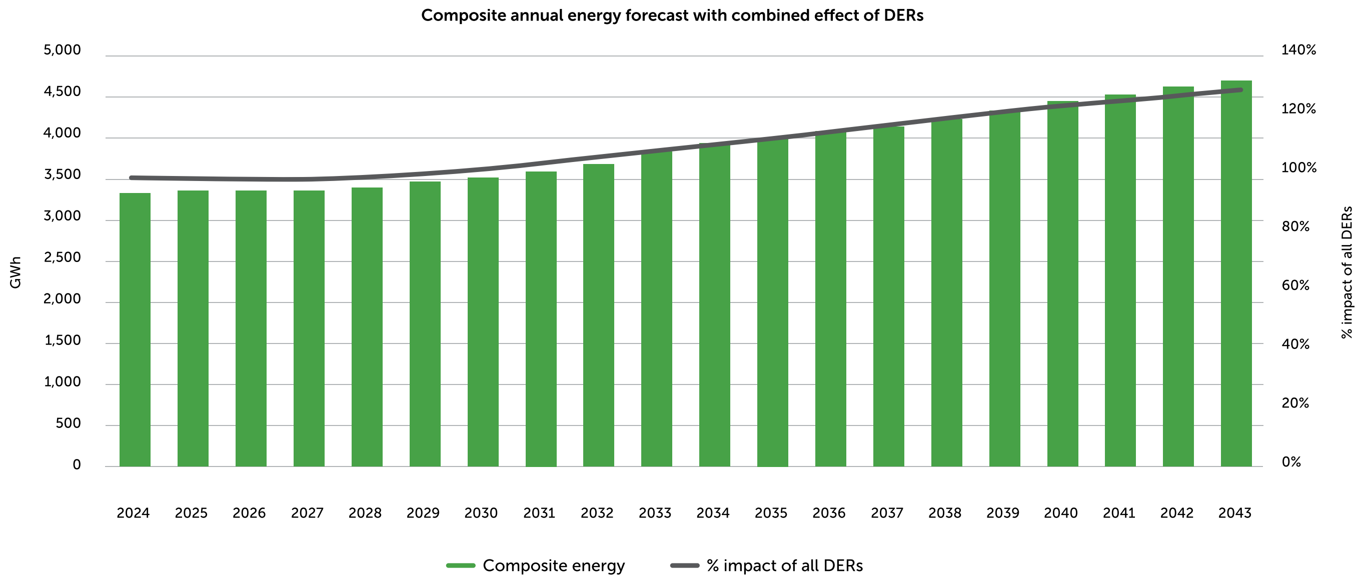



**Figure 37.** *Composite annual energy forecast with combined effect of DERs*

The green bars in Figure 37 show composite annual energy in gigawatt hours that Platte River's supply system must produce, and the solid black line shows the combined impact of all DERs as a percent. The combined effect of DERs reduces the annual energy need through 2029 and increases it afterwards, due to rapid increase in building electrification and EV load, reaching an almost 29% increase by 2043.

Figure 38 shows composite summer peak requirement and the combined percent impact of DERs. The green bars show composite summer peak demand in megawatts that Platte River's supply system must provide, and the solid black line shows the combined impact of all DERs. The combined effect of DERs reduces the summer peak demand through 2035 and increases it after, due to rapid increase in building electrification and EV load, reaching an almost 6% increase by 2043. The combined percent impact of DERs on summer peak demand is much lower than the percent impact on annual energy consumption because the two major DERs, EV and building electrification, do not increase the summer peak load as much as they increase annual energy consumption.

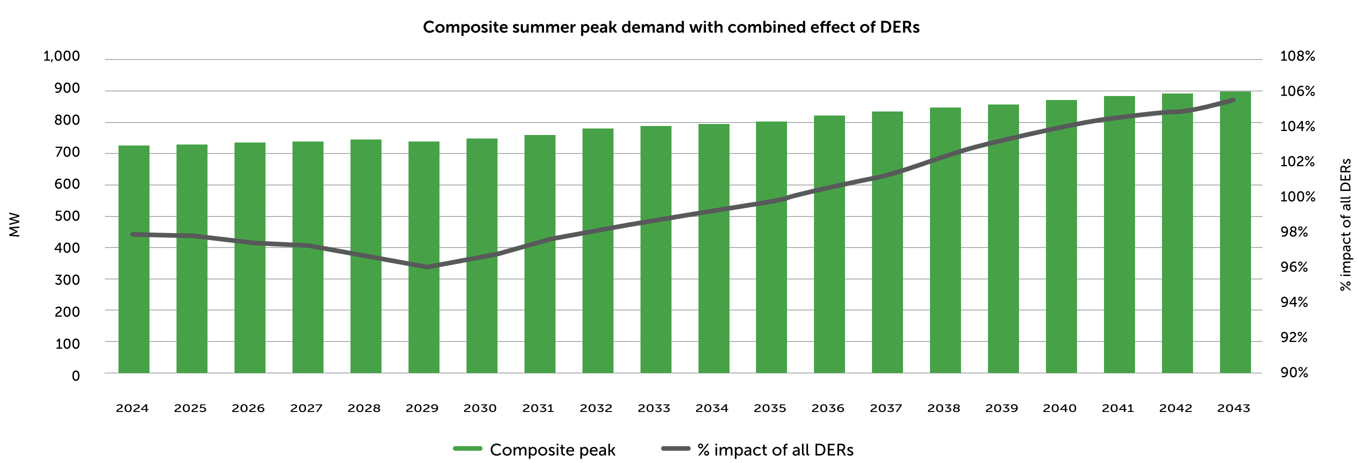



**Figure 38.** *Composite summer peak demand with combined effect of DERs*

# 06
# Supply-side assumptions

This section reviews assumed supply-side resources available to serve projected demand. These assumptions include commodity fuel prices, resource costs and their future trajectory, as well as assumptions about how Platte River interacts with other power suppliers in our region. The study period spans 20 years starting Jan. 1, 2021, largely because the typical life of investments for new generating capacity is 20-30 years.

## **6.1** Commodity price projections

Commodity price projections are a key input to resource planning. Platte River engaged Siemens Energy Business Advisory (previously Pace Advisory or Siemens) to provide regional natural gas, power, carbon dioxide ($CO_2$), nitrogen oxides, sulfur dioxide ($SO_2$), and mercury cost projections. Platte River projected coal prices based on unique coal supply plans for its coal-fired generation fleet. The following subsections discuss these commodity price projections in more detail.

### 6.1.1 Natural gas prices

Siemens provided a monthly natural gas price forecast for the Colorado Interstate Gas (CIG) trading hub, extending through the planning horizon. In addition to the base case pricing, Siemens also provided high and low gas price projections the planning team used to develop sensitivity cases. The high- and low-price projections reflect changes to the underlying fundamentals of the gas market, such as production volumes, export volumes or changes in consumption. All three gas price projections are shown in Figure 39.

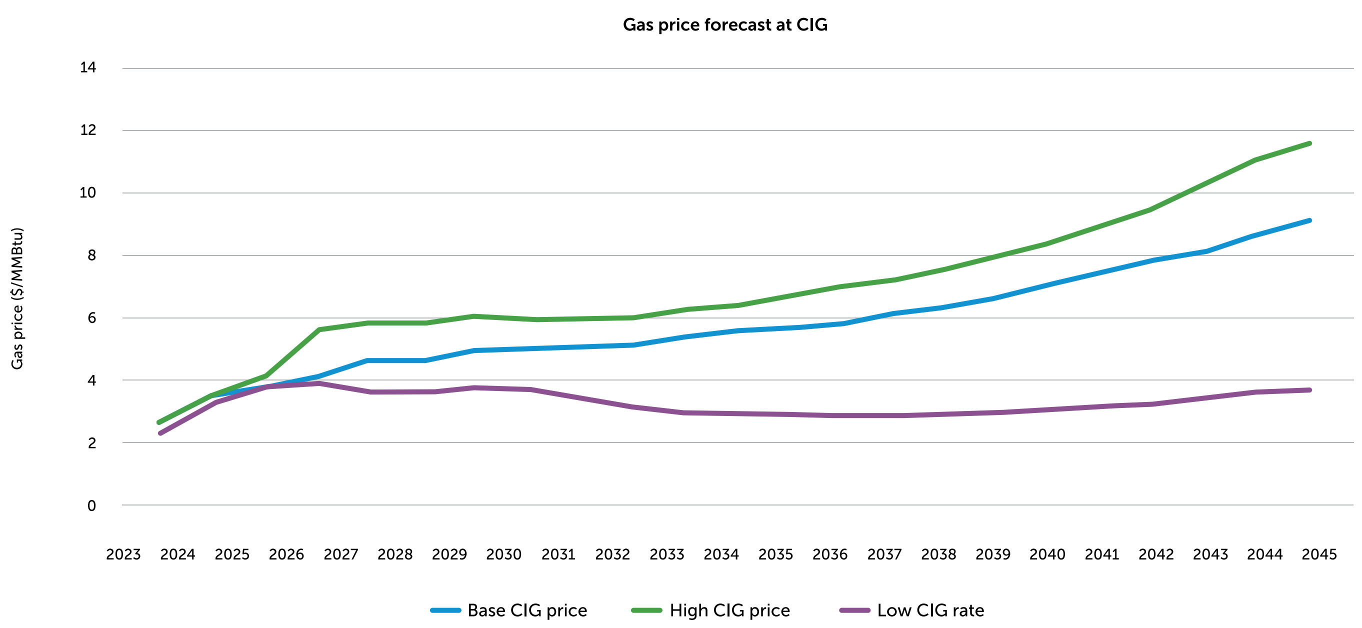



**Figure 39.** *Gas price forecast at CIG*

In addition to the above gas commodity prices, Platte River also pays transportation for natural gas delivered to the Rawhide site. Charges begin at \$1.05/MMBtu for 2024, based on actual expenses, and increase at the assumed inflation rate.

Analysis assumes additional gas-related cost for gas pipeline reservation to improve the reliability of gas supplies after coal retirements. Actual gas supply cost varies depending on consumption levels, but an average cost to firm gas supply ranges from \$35/kw-yr to \$50/kw-yr for different gas units. These costs begin in 2030 and end in 2040, when the models assume the units switch to 100% green hydrogen. To improve fuel supply reliability, we will analyze options for firming up gas supplies, such as on-site storage or constructing an additional pipeline to the Rawhide plant site.

## 6.1.2 Green hydrogen prices

Green hydrogen as a noncarbon-emitting fuel for traditional gas turbines has potential in the future, as technological and economical barriers for storing and transporting hydrogen diminish. Based on the recommendations from Black & Veatch, Platte River assumed a 50% blend of hydrogen with natural gas in 2035 and use of 100% hydrogen in 2040. Future hydrogen pricing is uncertain; IRP modeling assumed 2035 hydrogen prices five times the prices of natural gas by 2035, decreasing to three times of natural gas by 2045. Hydrogen prices can be expressed in \$/MMBtu or \$/kg units. Price projections are shown in Figure 40.

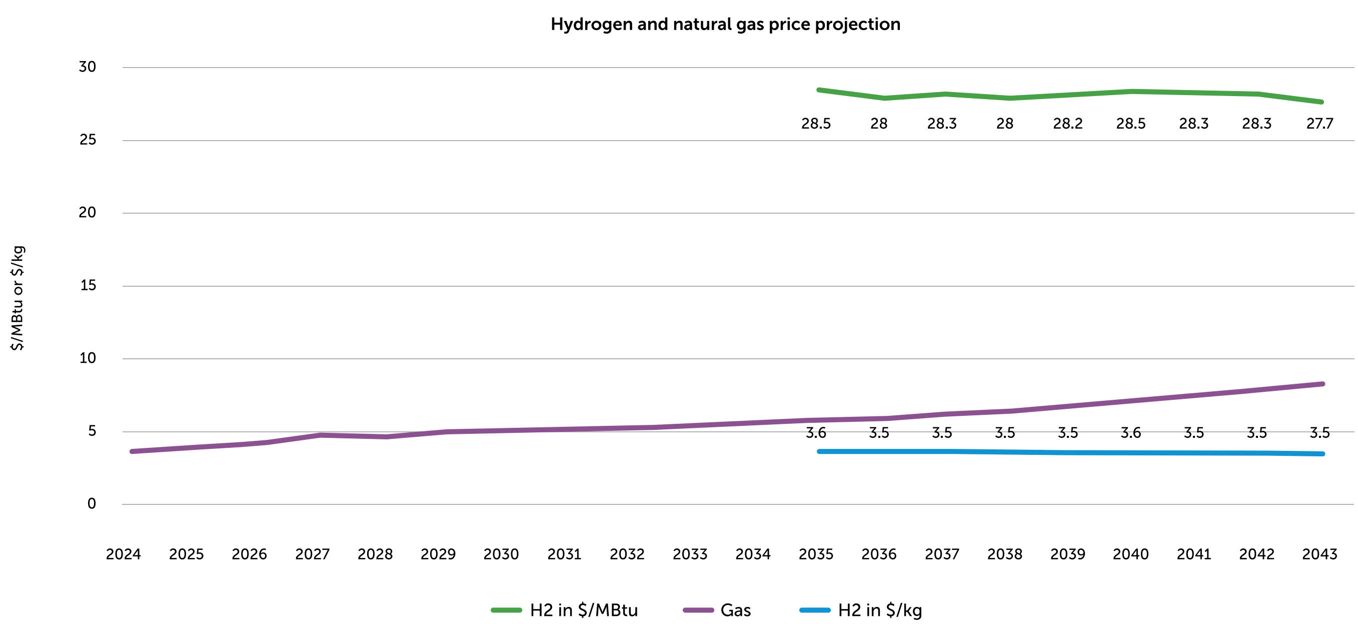



**Figure 40.** *Hydrogen and natural gas price projection*

## 6.1.3 Coal prices

Each coal plant in Platte River's portfolio operates with a unique coal supply arrangement. This means that price forecasts for Rawhide Unit 1 and the two Craig units are developed separately, as discussed below.

Rawhide receives coal from the Powder River Basin by rail and its price forecast is largely based on broader market prices. Near-term prices reflect existing contracts and prices that have been locked in with the supplier and near-term coal market assessments and indices. As locked-in quantities with prices tied to market indices decrease over time, the remaining coal is priced at Siemens's forecast for Powder River Basin coal. By 2027, the price forecast is based entirely on the forecasted commodity price from Siemens. The commodity price is adjusted to reflect mine-specific pricing. It includes additional costs for required dust suppressants and taxes passed through by the mine. Transportation expenses, based on the current rail rates projections, are also added to forecast delivered coal price.

The overall Craig coal price forecast is based on price forecasts provided by Trapper Mine, which is adjacent to the Craig plant. Platte River has a partial ownership interest in Trapper Mine and coal costs are determined on a "cash cost" basis, with no transportation costs incurred. Figure 41 illustrates the delivered coal prices for Platte River coal plants.

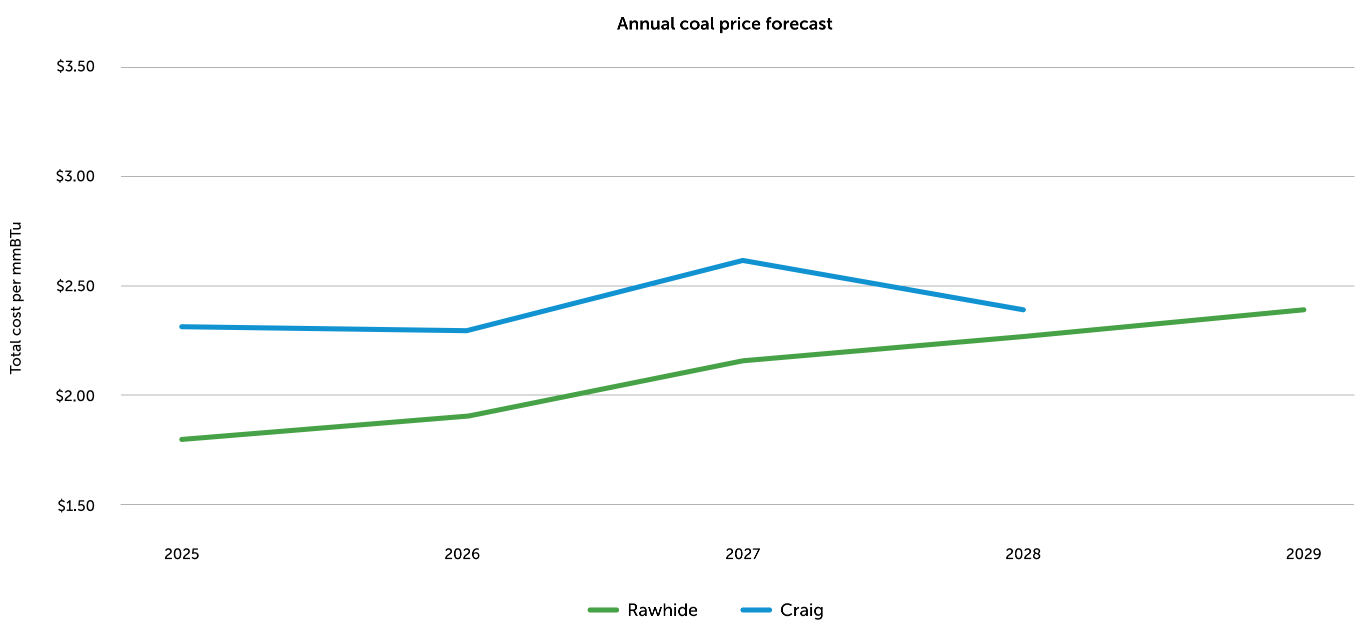



**Figure 41.** *Annual coal price forecast*

## 6.1.4 Regional power prices

Platte River's resources are dispatched in real time with resources from other utilities in the WEIS market to maximize economic exchange of power across the market. In addition to the real-time market, Platte River transacts with neighboring utilities bilaterally, selling excess power and buying power when needed. To simulate these bilateral transactions with neighboring utilities, resource planning models a regional market where Platte River can buy or sell when economical. Siemens has provided hourly future prices for Colorado area and these hourly prices are used in our simulations. During portfolio simulations, the Platte River system was allowed to buy power when the regional market price is lower than Platte River's marginal cost of production and allowed Platte River to sell excess power when the market prices are higher than its marginal cost. Net revenues from market transactions reduce the overall cost of providing power to Platte River's owner communities.

With more renewable resources on the regional grid, renewable energy becomes a bigger driver of power prices. Siemens predicts that average annual power prices will remain relatively stable over the 20-year planning horizon. However, daytime prices (labeled as "on-peak solar" prices in Figure 42) will decline as more solar generation is added.

Figure 42 shows our current forecast for on-peak and off-peak power prices, including solar and non-solar hours. The model defines on-peak hours as Monday-Saturday from 6 a.m. to 10 p.m., with on-peak solar 8 a.m. to 5 p.m. every day and on-peak non-solar 5 p.m. to 10 p.m. Monday-Saturday. Off peak hours are 11 p.m. to 5 a.m. Monday-Saturday and all day Sunday. As shown in Figure 42, on-peak non-solar prices (representing the evening hours) stay the highest and on-peak solar, which reflect the day and time when solar is plentiful, are the lowest prices.

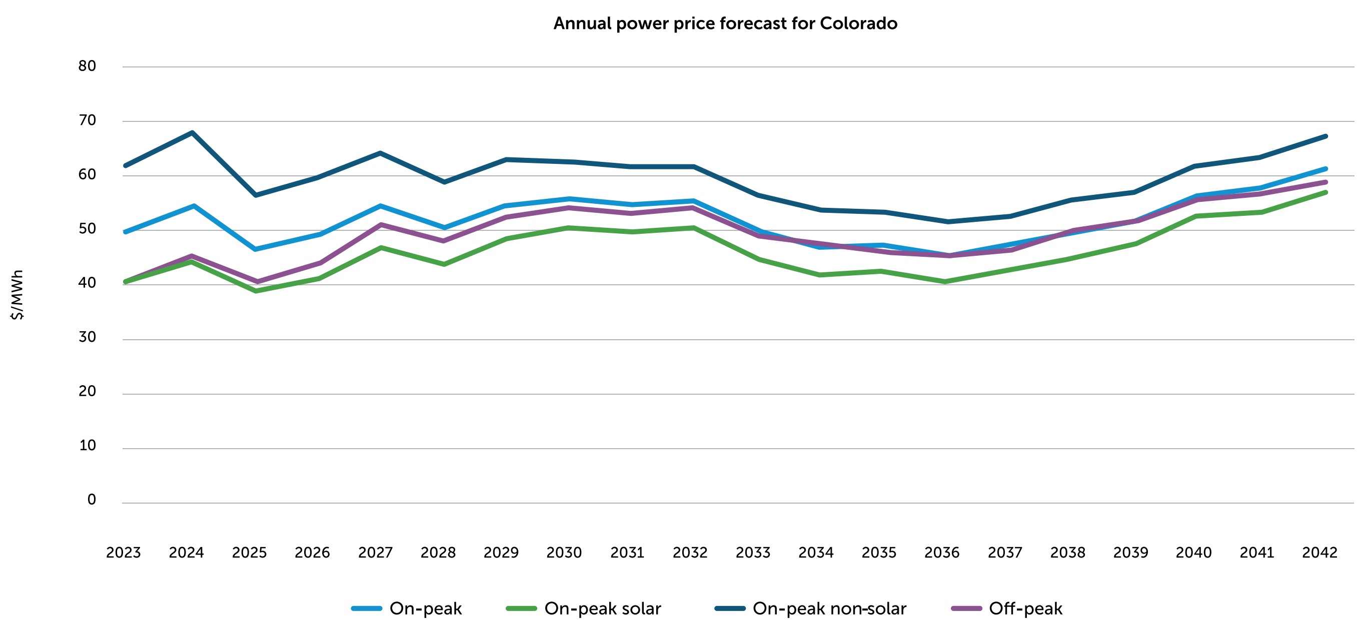



**Figure 42.** *Annual power price forecast for Colorado*

For the 2024 IRP, Siemens provided an hourly price forecast and the renewable energy patterns used in their price forecasting models, which helped correlate relationships between market prices and energy production from the intermittent wind and solar resources. Siemens also provided the natural gas and emission prices forecasts, which were appropriately correlated to an hourly level in the IRP assumptions to ensure internal consistency among various projections.

### 6.1.5 Carbon taxes embedded in projected energy prices

Siemens supplied a carbon price (tax) forecast based on its expectations concerning public policy discussions and potential legislation. A carbon tax will discourage carbon emissions.

Platte River also evaluated portfolio outcomes using a social cost of carbon. The social cost of carbon simulates total direct and indirect (such as healthcare or extreme weather events) cost to the society from continued CO2 emissions. The social cost of carbon projection was based on the guidance of the Colorado Air Quality Control Commission, which valued the social cost of carbon at $68 per short ton in 2020 with an escalation rate of 2.5%, as shown in Figure 43.

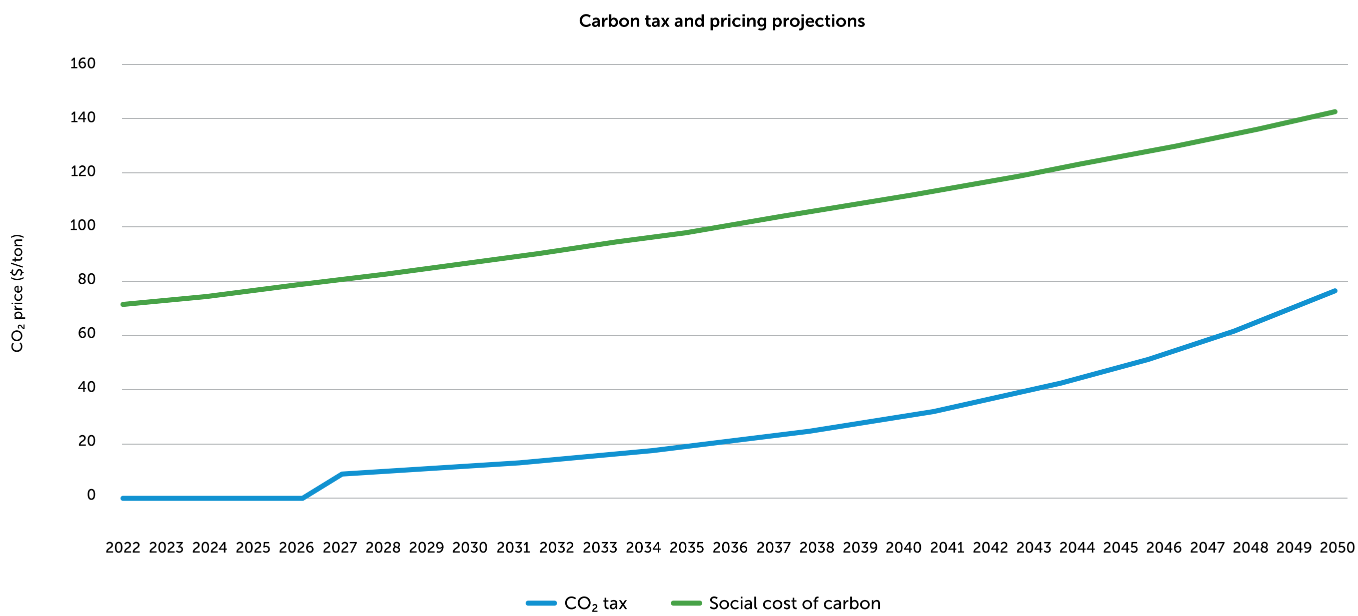



**Figure 43.** *Carbon tax and pricing projections*

## 6.2 Regional import/export limits

Platte River joined the WEIS market in April 2023, where Platte River's generation resources are jointly dispatched along with generation resources of other market participants to minimize dispatch costs for all market participants. When it joins SPP RTO West, Platte River will serve its load with a combination of owned resources and lower-cost resources from other market participants, implying real-time power sales and purchases with other RTO members. In addition, Platte River will continue bilateral transactions with regional entities, marketing excess energy through short- and long-term transactions. For IRP modeling, analysts assumed purchases or sales up to 150 MW in any hour. The 150 MW import/export limit means that market transaction volume remains realistic and that Platte River builds enough reliable energy generation to meet customers' needs and planning reserve margin requirements.

## 6.3 Supply-side generation resources

This section discusses all power generation resources Platte River considered to meet its customers' future electricity needs, beginning with our existing resources followed by committed resources. We then discuss additional future resources and the screening process to select candidate resources. A detailed discussion follows concerning the resources (both renewable and traditional) that Platte River is evaluating for future investment.

### 6.3.1 Platte River's existing resources

Platte River's existing supply-side resources consist of power plants, PPAs and community solar generation facilities. Distributed and community-owned solar were modeled as supply-side resources even though they may have unique contracts with retail load or with an owner community's distribution utility. For modeling purposes, they function as resources that serve community load. Tables 10-15 list Platte River's existing resources.

| Coal generation facilities | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation | Nominal retirement / contract expiration |
|---|---|---|---|---|
| Rawhide Unit 1 | 280 | 280 | 1984 | 2029 |
| Craig Unit 1 | 77 | 77 | 1980 | 2025 |
| Craig Unit 2 | 74 | 74 | 1979 | 2028 |

**Table 10.** *Platte River's existing coal resources*

| Natural gas (simple-cycle CTs) generation facilities | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation |
|---|---|---|---|
| Rawhide Unit A | 65 | 65 | 2002 |
| Rawhide Unit B | 65 | 65 | 2002 |
| Rawhide Unit C | 65 | 65 | 2002 |
| Rawhide Unit D | 65 | 65 | 2004 |
| Rawhide Unit F | 128 | 128 | 2008 |

**Table 11.** *Platte River's existing natural gas resources*

| Contracted wind resources | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation |
|---|---|---|---|
| Medicine Bow | 6 | 1 | 1998 |
| Silver Sage[11] | 12 | 2 | 2009 |
| Spring Canyon I[12] | 32 | 5 | 2014 |
| Spring Canyon II | 28 | 6 | 2014 |
| Roundhouse | 225 | 39 | 2020 |

**Table 12.** *Platte River's contracted wind resources*

| Contracted hydropower[13] resources | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation |
|---|---|---|---|
| Loveland Area Project | 30 | 30 | 1973 |
| Colorado River Storage Project | 60 | 48 | 1973 |

**Table 13.** *Platte River's contracted hydropower resources*

| Contracted solar resources | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation |
|---|---|---|---|
| Commercial solar power purchase program | 4 | 2 | Approved 2013 |
| Fort Collins community solar | 1 | 0.4 | 2015 |
| Foothills Solar (Platte River share) | 0.5 | 0.2 | 2016 |
| Rawhide Flats | 30 | 17 | 2016 |
| Rawhide Prairie | 22 | 12 | 2020 |

**Table 14.** *Platte River's contracted solar resources*

| Contracted storage resources | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation |
|---|---|---|---|
| Rawhide Prairie Battery | 1 MW x 2 hours | 1 | 2020 |

**Table 15.** *Platte River's contracted storage resources*

[11] Silver Sage wind has been sold through 2029, when its PPA with Platte River expires. It does not return as a resource.

[12] Both Spring Canyon resources were sold in 2020 through 2030. They will return to Platte River in June 2030 and serve Platte River customers for the remaining term of their contract (through 2039).

[13] Estimated effective capacity due to persistent drought conditions throughout the West.

## 6.3.2 Committed or expected resources

This category includes resources for which either a final contract has been signed or negotiations are ongoing. These resources are treated like existing resources. These resources are included in modeling as assumed available and not subject to change through the optimization and resource selection process. These resources are shown in Table 16.

| Committed resources | Nameplate capacity (MW) | Effective capacity (MW) | Commercial operation | Current status |
|---|---|---|---|---|
| Solar | | | | |
| Black Hollow | 150 | 31 | 2025 | PPA signed |
| New solar | 150 | 24 | 2026 | Negotiations ongoing |
| Storage | | | | |
| Community battery | 25 MW x 4 hours | 18 | 2026 | Negotiations ongoing |

**Table 16.** *Committed resources*

## 6.3.3 Future candidate resources

Platte River selected future candidate generation resources by reviewing data from credible public sources, its consultants and its own market intelligence as detailed below. This section provides an overview of data sources, selection process and details of the selected resources.

### 6.3.3.1 U.S. Energy Information Administration

The EIA publishes cost and performance of new generation every year in its annual energy outlook report. The EIA report[14] is comprehensive and covers state of the art in traditional, low-carbon and renewable power generation technologies. We selected the following technologies from this report for further evaluation:

- Onshore wind
- Solar photovoltaic
- Battery storage
- Aeroderivative combustion turbine
- Reciprocating internal combustion engine
- Carbon sequestration
- Modular nuclear
- Geothermal

Planning staff screened out the following technologies from this report, as they are not suitable for Platte River's future power supply portfolio.

- Coal with or without carbon sequestration
- Combined cycle with or without carbon sequestration
- Large nuclear
- Offshore wind
- Biomass
- Solar thermal
- Conventional hydro
- Fuel cells

### 6.3.3.2 Black & Veatch consulting support

In addition to the resources considered from the EIA report, Platte River engaged Black & Veatch[15] to assess the landscape of low- and no-carbon fuels, energy storage and dispatchable power generation technologies. The Black & Veatch report assessed the availability of these technologies for 2028 commercial operation. For technologies not available for 2028, they estimated their future costs and commercial availability in the next decade. Black & Veatch reviewed the following options:

- **Biofuels.** The study concluded biofuels for power generation are not a viable option at Rawhide due to limited fuel availability and significant modifications required in the equipment to burn this fuel. Biofuels are better suited for transportation applications, rather than large power generation.

- **Hydrogen** – both green and blue. Green hydrogen is produced by an electrolyzer using renewable electricity, while blue hydrogen is produced from natural gas and the CO2 produced in the process is sequestered and stored in the ground. Hydrogen can be used as fuel in traditional power generation machines like CTs with some modifications. But there are significant technoeconomic challenges to store and transport hydrogen. The study concluded that green hydrogen could be a viable option for Platte River starting in the middle of the next decade.

[14] https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

[15] Results from the generation technology screening by Black & Veatch are accessible on Platte River's IRP microsite at prpa.org/2024irp/information.

- **Renewable natural gas.** Renewable natural gas is produced mostly at landfill or biowaste locations. The study concluded that renewable natural gas for power generation at the Rawhide site is not a viable option due to limited fuel availability. This fuel is better suited for small power generation at or near locations where the fuel is produced, such as landfill or wastewater treatment sites. Another possible use of renewable natural gas is for transportation, like the City of Longmont using renewable natural gas from its wastewater facility in the waste services truck fleet, displacing the use of diesel fuel. In some cases, renewable natural gas can be refined enough to meet the pipeline quality natural gas standard and can be pumped back into the gas network.

- **Ammonia.** Since transporting hydrogen over long distances is technologically and economically challenging (because hydrogen is a very light-weight molecule), industry is considering converting hydrogen into ammonia and then transporting it. At the destination, ammonia can be used directly in power generation or converted back to hydrogen and then used. The study concluded ammonia for power generation is not a viable option. It is better suited for transportation applications, rather than large-scale power generation.

- **Carbon capture and sequestration.** Carbon capture and sequestration technology was considered for removing CO2 from the existing combustion turbine units at the Rawhide site. The study concluded carbon capture and sequestration is not a viable option at Rawhide due to high cost of CO2 removal in peaking units (like those at Platte River, where combustion turbines are expected to run less than 20% of the time), and lack of known places to sequester CO2. Carbon capture and sequestration technology is a better option for baseload applications, where the generation source is running continuously and where the large capital cost can be spread over numerous tons of removed CO2. Additionally, carbon capture and sequestration technology is in the early commercial stages of development, with few proven and successful applications for power generation.

- **Long duration energy storage.** The study concluded that long-duration energy storage is an emerging technology, but not ready for commercial operation in 2028. This technology has potential and may become commercially available by the middle of the next decade. Platte River decided to plan for a 10 MW pilot long-duration energy storage project by 2030 and assume the technology would be available for commercial applications by 2035.

- **Flexible and low CO2 emitting thermal power generation.** In addition to the low- or no carbon emitting power generation options discussed above, the study reviewed various traditional combustion turbine and reciprocating internal combustion engine technologies that are flexible, reliable, efficient and hydrogen-capable. Three key future dispatchable technology requirements will be reliability, flexibility, and the ability to provide power for at least one week during dark calms. Because low or no-carbon options were not commercially available, the study recommended using gas-fired combustion turbines or reciprocating internal combustion engines for commercial operation in 2028 and progressively converting to green hydrogen when it is economically available in large quantities. Combustion turbine and reciprocating internal combustion engine vendors claim that these machines will be capable of burning about 30% hydrogen by 2028.

#### 6.3.3.3 Platte River's own market intelligence

Plate River's portfolio integration team monitors markets and collects information informally and formally through requests for information and requests for proposals. This engagement informs Platte River of the latest technology and pricing trends in the area. EIA, Annual Technology Book (ATB) or consultants can provide market trends and average prices, but the real prices for our area are available only through engagement with developers and vendors. Platte River conducted a solar and storage RFP in 2022 and started a wind RFP in 2023. These market interactions were valuable for collecting information about the projects being developed in our region—their costs, locations, schedules and technologies. This information was used to input costs of renewable and storage technologies in IRP modeling.

#### 6.3.3.4 NREL's Annual Technology Book

NREL provides cost, efficiency and technology improvement trends of renewable and storage technologies in the ATB every year. We used the data in the 2022 ATB for this IRP, as it was the latest available in the spring of 2023 when staff finalized assumptions.

After a detailed review of all the sources mentioned above and internal deliberations, Platte River decided the following:

- For wind, solar and four-hour storage costs, we used our own market intelligence data for early year prices where data was available from multiple vendors.
- After the first three years, we used cost escalation and efficiency improvement rates proposed by the ATB.
- Actual cost data used for each technology is shown in the following sections.

For dispatchable resources, Platte River relied on the recommendations of Black & Veatch. Platte River decided the best option is to use highly flexible, state-of-the-art, hydrogen-capable aeroderivative combustion turbine technology. These machines will initially use natural gas fuel and by 2035 may start using 50% green hydrogen blend and by 2040 may use 100% green hydrogen. The process of selecting aeroderivative technology is discussed in section 6.3.7.

### 6.3.4 New wind resources

While wind resource availability within Platte River's service territory is limited, wind is abundant to the north and the southeast. Most likely, our future wind will come from southeast Wyoming or eastern Colorado. We have assumed that the southeast Wyoming wind will be delivered to Platte River through existing transmission capacity that will become available after retirement of Craig coal generation.

Eastern Colorado wind would be delivered through a neighboring transmission system at a cost of $6/MWh in 2023 and escalating with inflation. Because the existing transmission infrastructure in southeast Wyoming is limited, only 200 MW of wind is expected to be procured without incremental transmission cost. Any future wind will include a transmission charge or new transmission infrastructure at an assumed cost of $6/MWh.

New wind resources are assumed to be procured under PPAs for 100 to 200 MW blocks. PPA payments compensate the developer or the owner for capital costs (depreciation and returns), financing costs, interest during construction, taxes (sales, property, and income) and ongoing operating and maintenance costs. PPA prices for wind are based on recent quotes from project developers in the region. We assumed future wind prices will escalate based on the 2022 ATB future wind cost curves.

Southeast Wyoming wind is assumed to have an average annual capacity factor of 42.5%, while the eastern Colorado wind was modeled with a 45% capacity factor.

Wind projects (existing or new) carry ancillary service charges through 2025. Beyond 2025, we assume those costs cease with entry into a regional market. The combined cost of wind ancillary services in 2024 were modeled at $1.24/kw-mo.

Figure 44 shows wind costs for the two locations along with solar costs. As mentioned earlier, PPA prices are generally fixed for their terms (typically 20-30 years). Figure 44 assumes that for 2026, the southeast Wyoming wind PPA price will be fixed at $35/MWh for the PPA term, while for the wind PPA signed in 2030, it will cost $33.65/MWh for the life of the project.

### 6.3.5 New solar resources

New solar resources were considered as 50 MW block sizes priced at a 30-year levelized PPA payment, including transmission interconnection costs. Solar generation is assumed to have an annual capacity factor of 28%. Platte River received solar price data based on recent RFPs and negotiations with developers. These prices were escalated with NREL's 2022 ATB solar cost projections.

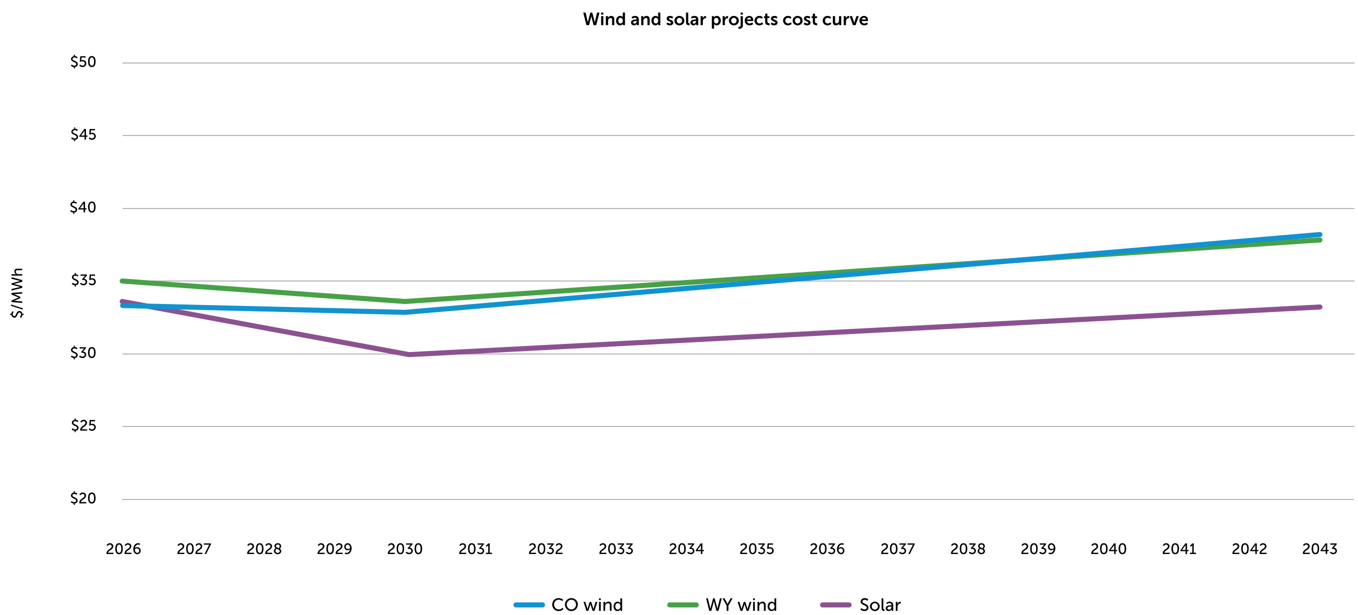



**Figure 44.** *Wind and solar projects cost curve*

Platte River assumed that new solar projects will be built within the existing Platte River transmission footprint. Consequently, no new transmission capital costs or third-party wheeling costs were assumed for solar generation. Solar ancillary service costs in 2024 were assumed at $0.09/kw-mo.

## 6.3.6 New storage resources

Energy storage is the keystone in a deeply decarbonized power supply portfolio. A 100% renewable power supply portfolio using wind and solar as the main source of energy will need energy storage from a few seconds to several days to complement supply intermittency. Platte River considered a variety of different commercially available battery storage technology options, including lithium-ion batteries for four-hour storage duration, flow batteries for 10-hour storage duration and long-duration energy storage batteries for 100-hour storage duration. These battery types will provide different services to support the grid while complementing renewable intermittency.

Four-hour lithium-ion battery technology is mature and commercially available. We assumed 200 MWh of storage per 50-MW four-hour battery, which would provide up to four hours of discharge capacity at a rate of 50 MW per hour. Four-hour batteries were assumed to have an 85% round trip storage efficiency. The economic life of a four-hour battery was modeled to be 20 years. Like wind and solar, 2024 prices for four-hour battery storage were based on the recent RFP and vendor negotiations. Future prices escalate based on the 2022 ATB. See the cost projections in Figure 45.

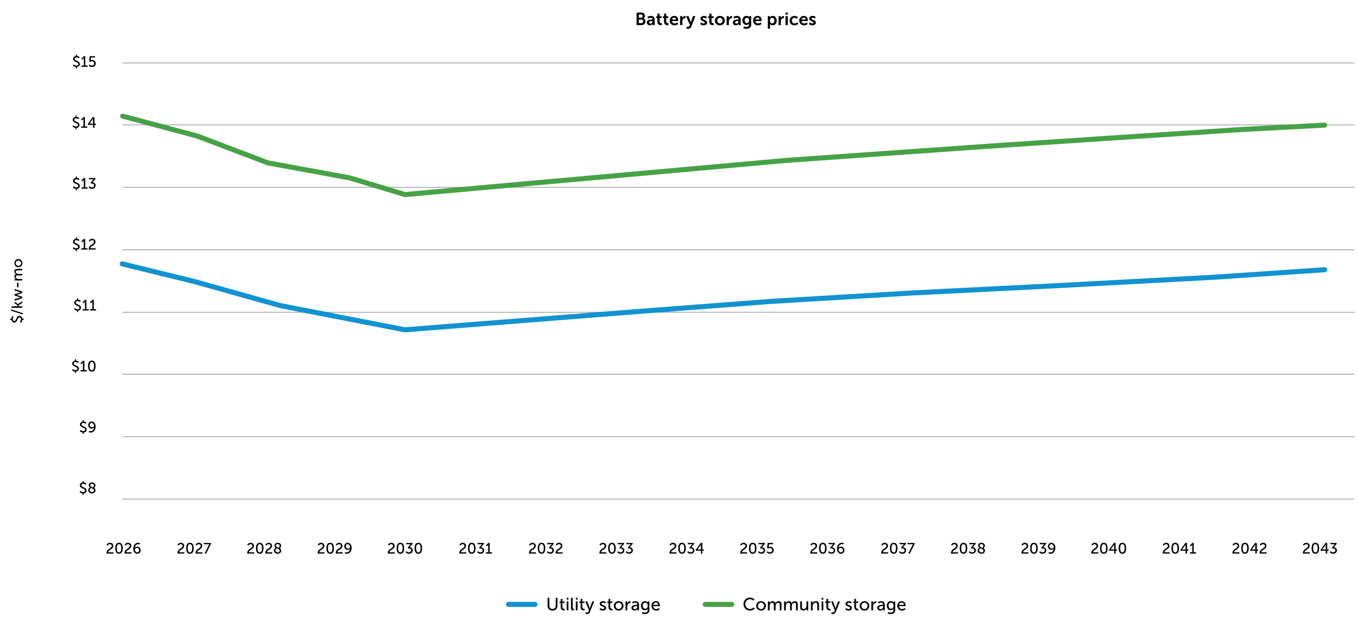



**Figure 45.** *Battery storage prices*

Ten-hour flow batteries are an emerging technology with no existing commercial installations as of 2023. We worked with a vendor to get cost, efficiency, and performance details. Based on the data provided by the vendor, this technology was not found to be economical during our early technology screening and minimal cost portfolio development process. Therefore, this technology was not considered as a resource in the IRP. However, this technology has potential to become part of the future power supply portfolio. As the technology matures, Platte River will consider it.

Long-duration energy storage is critical for supplying power during extended dark calm periods. Like flow batteries, this technology is also under development with no existing commercial installations as of 2023. Platte River analyzed the cost, efficiency, and performance details of long-duration energy storage. When fully developed and commercialized, long-duration energy storage will reduce the need for fossil generation to provide backup power and reliability in a renewable portfolio. Platte River plans to integrate a 10 MW pilot unit before 2030. For IRP modeling, we assumed that the technology will be commercially available by 2035. The current capital cost of this technology is high, and the round-trip efficiency is low. We assumed cost reduction and performance improvements over time as the technology matures and finds commercial applications.

## 6.3.7 New dispatchable thermal generation resources

As mentioned earlier, after a thorough review of all the options for no- or low-carbon fuels, and for dispatchable generation technologies, Black & Veatch recommended Platte River use natural gas-fired generation for 2028 commercial operation and then convert to green hydrogen fuel when it is commercially available. Platte River and Black & Veatch looked at 50+ options and screened down to the seven listed in Table 17 for detailed assessment.

| Characteristic | Unit | LM2500 | LM600 | LMS100 | RICE | 7F CC conver-sion | LM600 CC | SGT800 |
|---|---|---|---|---|---|---|---|---|
| Unit size | MW | 28 | 40 | 90 | 17 | 17-116 | 31-44 | 55 |
| Heart rate | btu/kWh | 9,875 | 9,649 | 8,820 | 8,510 | 6,646 | 7,087 | 9,707 |
| Cost per MW | $M/MW | $1.8 | $1.7 | $1.2 | $1.7 | $2.2 | $2.3 | $1.4 |

**Table 17.** *Screened dispatchable technologies*

LM2500, LM6000 and LMS100 are aeroderivative CTs manufactured by General Electric. RICE is reciprocating internal combustion engine. The next two were combined cycle options; converting the existing 7F CT at Rawhide station or install 4 LM6000 CTs with combined cycles. Finally, SGT800 is a combination of frame and aeroderivative technologies manufactured by Siemens.

After analyzing the levelized cost of energy and reviewing operational characteristics of the seven technologies, a smaller group of four featured in Table 18 was selected for more detailed assessment. These four technologies were further analyzed in detail for characteristics like reliability, emissions, economic value, operational flexibility, fuel versatility, constructability and market performance. During this detailed evaluation, higher weights were assigned to the factors aligned with Platte River's three pillars of reliability, environmental responsibility and financial sustainability. This analysis concluded that aeroderivative technology was the best option for Platte River. The LM6000 technology was selected as the presumed technology for inclusion in the supply portfolio.

| Qualification | Weight | Option 1 | Option 2 | Option 3 | Option 4 |
|---|---|---|---|---|---|
| Reliability | 30% | 1.52 | 2.52 | 2.7 | 1.51 |
| Emissions | 25% | 0.7 | 2.41 | 2.34 | 1.69 |
| Costs | 20% | 1.55 | 1.47 | 1.55 | 2 |
| Operational flexibility | 10% | 0.9 | 0.91 | 0.88 | 0.8 |
| Fuel versatility | 5% | 0.05 | 0.36 | 0.36 | 0.42 |
| Constructability | 5% | 0.45 | 0.45 | 0.45 | 0.35 |
| Market performance | 5% | 0.4 | 0.5 | 0.45 | 0.45 |
| **Total weighted score** | **100%** | **5.57** | **8.62** | **8.72** | **7.21** |

**Table 18.** *Results of detailed screening of four selected technologies*

# 07
# IRP design

## 7.1 Studies

The following studies support this IRP. All studies are available on the IRP microsite.

- PRM and ELCC study by Astrape Consulting
- Beneficial electrification forecast by Apex Analytics
- Distributed energy resources forecast and potential study by Dunsky
- Extreme weather events and dark calm analysis by ACES
- Independent review of dispatchable capacity needs by Black & Veatch
- Generation technology screening by Black & Veatch

Additionally, this IRP uses fundamental market analysis of supply and demand in the region provided by Siemens, and a locational marginal pricing assessment by ACES.

## 7.2 Objectives

The objective of this IRP is to continue Platte River's journey toward achieving the goals of the RDP by developing a roadmap to meet the owner communities' needs for reliable, environmentally responsible and financially sustainable energy and services using a diverse power supply portfolio.

## 7.3 Planning for a reliable future power supply

Power supply reliability is a key responsibility of a utility. It is a foundational pillar for Platte River's planning and operations. Platte River plans to join a full organized energy market in 2026, which will take over transmission planning and some operational responsibilities. In a market, a load-serving entity like Platte River is required to bring enough resources to reliably serve its load according to the reliability criteria enacted by the market operator. Markets allow a wider access to improve economics and reliability under varying weather and operating conditions, but they do so by relying on the resources contributed by each market participant. This chapter covers reliability modeling in the IRP and the development of different power supply portfolios to cover a wide range of future possibilities.

## 7.3.1 Power supply reliability

As society's dependence on electricity increases, power supply reliability is becoming more critical. Electric reliability is not only the foundation for commerce; our security and safety depend on it. This critical dependence became tragically clear when Texas power outages during Winter Storm Uri caused 246[16] deaths  and billions of dollars in economic losses.

Power supply reliability is the ability of a power system to keep the lights on under changing supply and demand conditions. Electric utilities must plan, design, construct and operate an electric supply system for reliability of supply.

There are a few terms used under the broad umbrella of reliability:

- Adequacy is a measure of the ability of a power system to meet the electric power and energy requirements of its customers within acceptable technical limits, considering scheduled and unscheduled outages of system components.
- Security is the ability of the power system to withstand disturbances.

[16] Texas winter storm: 246 Texans' deaths classified as winter-storm related (kxan.com).

[17] https://www.energy.gov/articles/economic-benefits-increasing-electric-grid-resilience-weather-outages

- Resilience is the ability to quickly adapt and recover from a disruption, with minimal impact.

Historically, threats to power supply reliability included equipment failure (at the distribution, transmission, or generation level) or extreme weather like hurricanes, floods, snowstorms and heat storms. More than 90% of the power supply interruptions or reliability events can be attributed to breakdowns in the distribution system.[17]

Distribution system interruptions are typically localized and affect a small number of customers. Reliability events that stem from interruptions on the generation or transmission system, or lack of generation, are broader reaching and potentially more consequential. With increased reliance on wind and solar generation in the future, an additional threat to reliability will be low or no production from these intermittent resources for extended periods.

In our IRP process, Platte River focuses on reliable, environmentally responsible and lowest reasonable cost power supply portfolios. Some of the major variables that drive power supply reliability in our planning process are:

- Occasional generation equipment failures
- Load forecast uncertainty
- Variability of hourly wind and solar generation patterns
- Occasional extreme weather (such as heat or cold waves)
- Extended periods of low or no renewable generation

After an extensive review of hourly generation profiles of solar and wind, we found that there are certain times when there is very little or no renewable generation for extended periods. We call these incidents dark calms. We have found that dark calm events occur frequently and can last from a day to as long as seven days.

While our definitions of reliability and related concepts are general, over the years the power industry has developed specific metrics and methods to plan for a reliable supply portfolio as discussed in the next section. A starting point for developing a reliable power supply is a resource adequacy study. This study simulates a future power supply portfolio under varying conditions of power supply and power demand to assess its reliability.

## 7.3.2 Planning for a reliable future portfolio

### 7.3.2.1 Reliability metrics for planning

The North American Electric Reliability Corporation, the regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid, defines requirements for resource adequacy in Standard BAL-502-RFC-02.[18] This standard requires utilities to "calculate a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1." This metric is also referred to as Loss of Load Expectation (LOLE) of 0.1 per year or LOLE of one day in 10 years, or sometimes, as "One Day in Ten Years" (ODTY). This metric has been widely used in planning studies since the early days of modern power systems.[19]

This metric has traditionally guided investment in generation to provide reliability accepted as the optimal target. Historically, ODTY or 0.1 day LOLE per year has required utilities to maintain a 10-15% PRM. PRM is defined as the percent additional firm capacity relative to the peak demand in a future year. Specifically,

$$\text{PRM} = \frac{\text{Firm capacity - peak demand}}{\text{Peak demand}}$$

Historically, PRM covered planned or unplanned outages (equipment breakdowns) and load forecast error due to weather and economic growth uncertainty. Following the retirement of dispatchable coal generation (which provides

firm capacity) over the past decade, and with the introduction of intermittent renewable generation resources, the structure of power supply portfolios is rapidly changing.

LOLE of 0.1 day per year is still the dominant metric in the power industry, but some alternatives are being proposed and debated.[20] The main criticism of 0.1 day LOLE per year metric is that this probabilistic calculation does not adequately measure the depth (how much power was lost, or how many customers lost power), breadth (how long power was lost) and the frequency (how often power was lost).

In a recent report,[21] EPRI summarized the existing and proposed metrics, arguing that a single metric such as ODTY may conceal some risks and may not be able to sufficiently capture

the future challenges to the power grid from:

- Rapid decarbonization of power supply with the retirement of dispatchable resources and adoption of intermittent renewables.
- Adoption of electrification in transportation and heating.
- Adoption of DERs with wider customer involvement.
- Climate change and extreme weather events.

With the introduction of renewable generation, the concept of planning for the “Peak Hour” of the year is giving way to planning for every hour in the year. The hour when the system experiences peak demand is less important than the load net of renewables. For example, Figure 46 from New York ISO[22] shows that typically they experience peak demand between 3-4 p.m. in July, but, due to solar generation, the net peak demand is lower and shifts to 5-6 p.m.

[18] https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf

[19] https://www.astrape.com/wp-content/uploads/2024/01/EISPC_The_Economic_Ramifications_of_Resource_Adequacy_White_Paper.pdf

[20] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/ra_t3b2_workshop-1_presentation-telos-and-gridlab.pdf

[21] https://www.epri.com/research/products/000000003002023230

[22] https://www.nyiso.com/-/shaving-peaks-with-the-sun

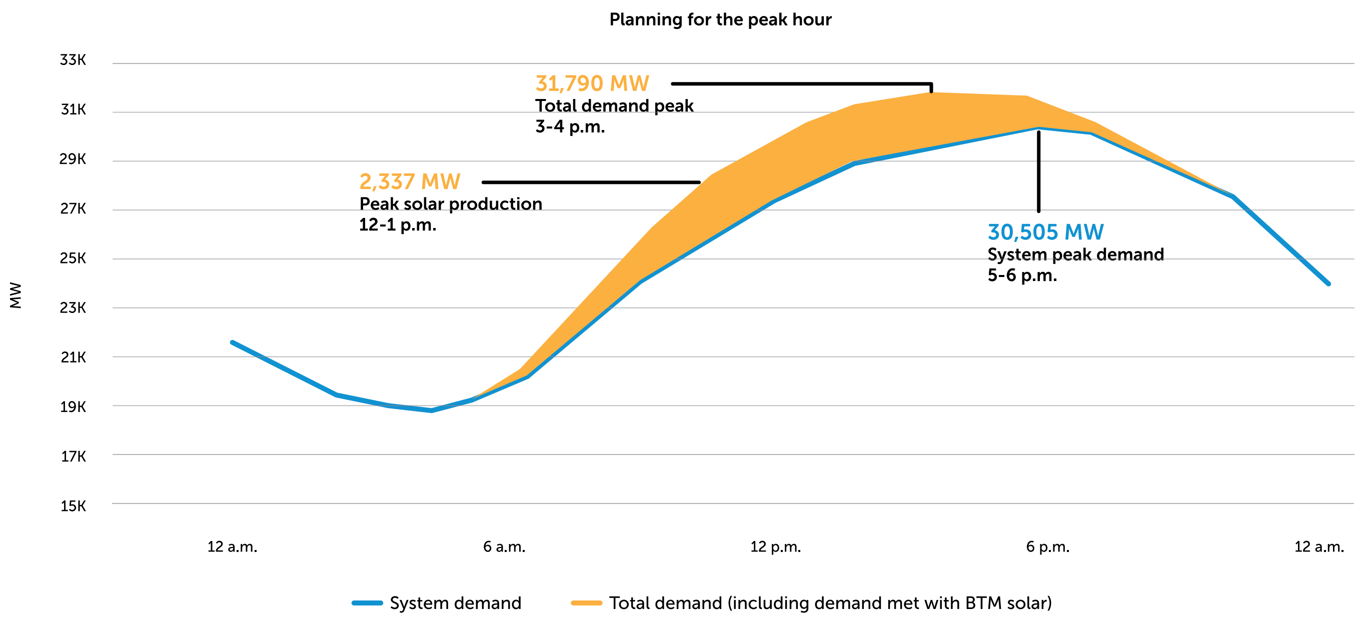



**Figure 46.** *Planning for the peak hour*

Other parts of the country experience similar phenomena. Wind generation may shift the net peak demand to different hours. In fact, the Western Electricity Coordination Council (WECC), the entity responsible for reliability of the electric grid in 13 western states (including Colorado), is proposing to estimate resource adequacy for every hour, targeting an hourly LOLE of 0.002%.[23]

## 7.3.2.2 Platte River PRM for future planning

For the 2020 IRP, Platte River used a 15% PRM as its reliability metric. With the changing portfolio mix in the region[24] and with the backdrop of ongoing discussions in the industry, we engaged Astrape Consulting to perform a resource adequacy[25] study for this 2024 IRP. This study computed PRM and ELCC[26] of intermittent renewable resources, small amounts of energy battery storage and DERs. The study focused on the year 2030 and modeled the Platte River supply portfolio, along with other utilities in Colorado. The study assumed these utilities will develop the power supply portfolios projected in their respective IRPs and will be part of a functioning market. The study concluded that all Colorado utilities, including Platte River, would need a PRM of 19.9%. This value, though higher

[23] https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf&action=default

[24] Platte River has filed a voluntary clean energy plan committing to reduce its 2030 $CO_2$ emissions by at least 80% from 2005 levels.

[25] https://www.prpa.org/wp-content/uploads/2023/11/2024IRP-PRM-and-ELCC-study-by-Astrape.pdf

[26] ELCC of a resource is the measurement of that resource's ability to produce energy at the time of peak demand.

[27] https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf

than the 2020 IRP PRM of 15%, aligns with the WECC-recommended Planning Reserve Margin Index or Variability Margin Index in its 2023 Western Assessment of Resource Adequacy[27] report. Power markets like the Midcontinent Independent System Operator (MISO) and SPP are also looking at higher PRMs than previously recommended due to coal retirements and more intermittent energy integration.

Astrape's proposed PRM of 19.9% for 2030 incorporates its analysis of Colorado, utilities including Xcel Colorado, Colorado Spring Utilities and Black Hills Colorado, using their modeling platform Strategic Energy & Valuation Model, which is also used by major U.S. utilities and several regional power pools. Astrape modeled major uncertainties like weather by using 42 years of historical data for hourly wind, solar and load shapes, three to five days of dark calms, five scenarios of future load forecast error and 300 scenarios of generation availability, for a total of 63,000 simulation scenarios for each hour of the year 2030. This comprehensive analysis produced the relationship between LOLE and PRM as shown in Figure 47.

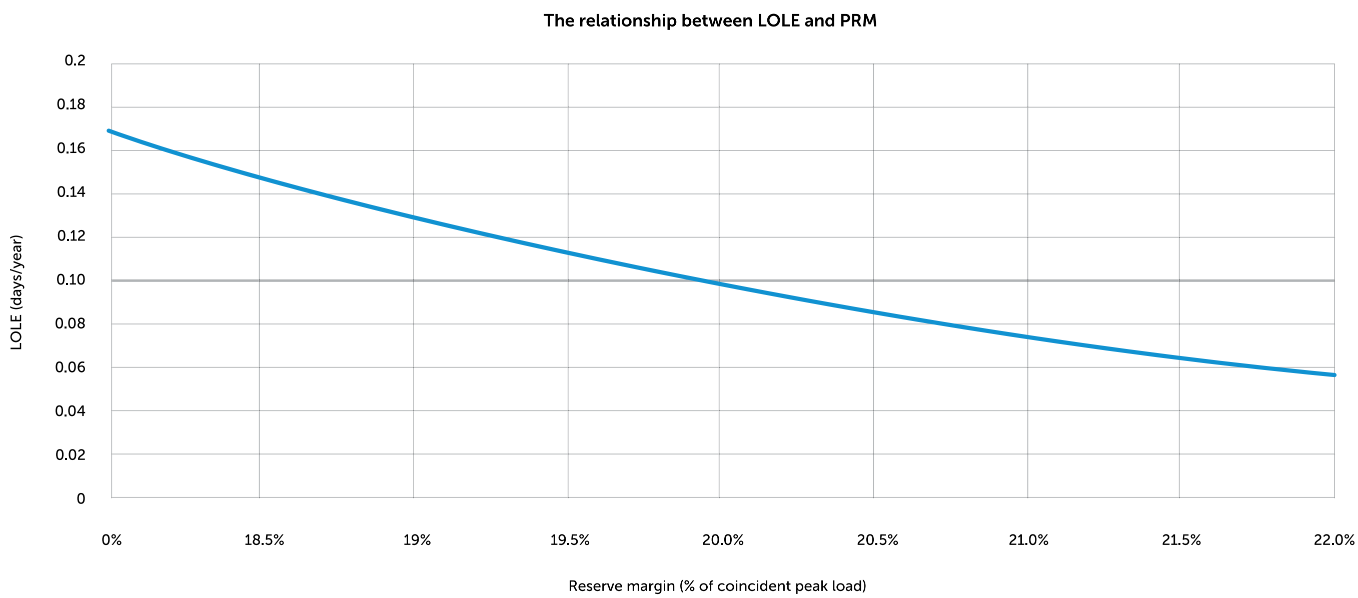



**Figure 47.** *The relationship between LOLE and PRM*

At 0.1 day LOLE per year, the PRM is 19.9%. If we were to build a more reliable system with a LOLE of 0.06, or one outage every 16 years, we will need a PRM of 21.8%. On the other hand, a LOLE of 0.16, with an expected outage every six years, would require a PRM of 18.4%. Essentially, the more spare capacity we have, the less likely we are to face a supply shortage or LOLE.

As mentioned earlier, EPRI recommends not relying on one metric. Utilities and other entities are considering many metrics. In addition to the PRM, we used Loss of Load Hours (LOLH) in our IRP modeling. LOLH measures the average duration of outages. We used LOLH 0.2 during reliability testing of our portfolios.

### 7.3.2.3 ELCC values for renewables and limited energy resources

The ELCC of a renewable or energy-limited resource measures its expected contribution to peak demand. For example, 100 MW from a coal or gas fired plant can provide 100 MW at the time of peak. When running at full load, it will reduce the peak load by 100 MW. The ELCC of this resource is 100 MW or 100%.

But 100 MW of wind, solar or four-hour storage may or may not be able to provide 100 MW at system peak. This means its ELCC will be lower than the nameplate capacity. This can be seen for solar generation in the example shown in Figure 48. It shows hypothetical hourly load and solar generation forecast for a summer day in 2030 for Platte River's system.

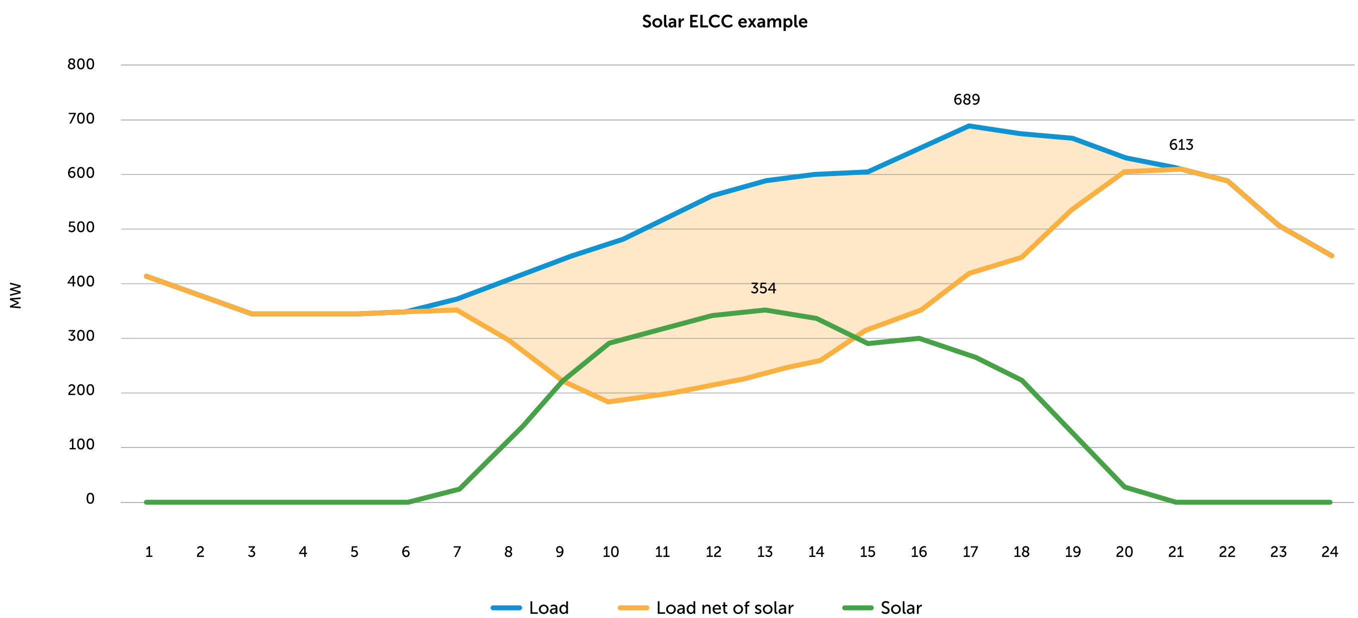



**Figure 48.** *Solar ELCC example*

The blue line shows hourly load for 24 hours across the day. The peak load during the day is 689 MW at hour 17 or 5 p.m. The green line shows solar generation. It starts around 6 a.m., peaks at 354 MW at 1 p.m. and drops to zero by 9 p.m. The orange line shows hourly load net of solar generation. Solar generation reduces the load by the shaded area. The orange line shows that the peak hour of the load has shifted from 5 p.m. to 9 p.m. and is 613 MW. So, the solar generation has reduced the peak demand by 76 MW (689 minus 613). While the maximum solar generation is 354, the nameplate of installed capacity of solar is 507 MW in this example. For this day, solar ELCC is 76/507=15%. In other words, installed capacity of 507 MW reduces the peak demand by 76 MW. Put another way, the effect solar had on the peak is that it reduced peak by 76 MW.

As we install more solar, its impact on reducing peak will be zero, because the peak demand hour has already moved to 9 p.m., after sunset when solar stops producing. In that case, the incremental ELCC of solar after 507 MW is zero. This example shows just one hypothetical day. In reality, ELCC calculations are computed after thousands of simulations under different load and weather conditions.

ELCC of wind and other resources follows the same declining pattern with more resource additions. As more wind is added, the incremental contribution of the next wind project to reduce peak demand continues to decline. Figure 49 shows the ELCC values of solar, wind and four-hour storage through time as computed by Astrape, which we used  for this IRP. As utilities in Colorado add more of these resources over time, their ELCC contributions diminish.

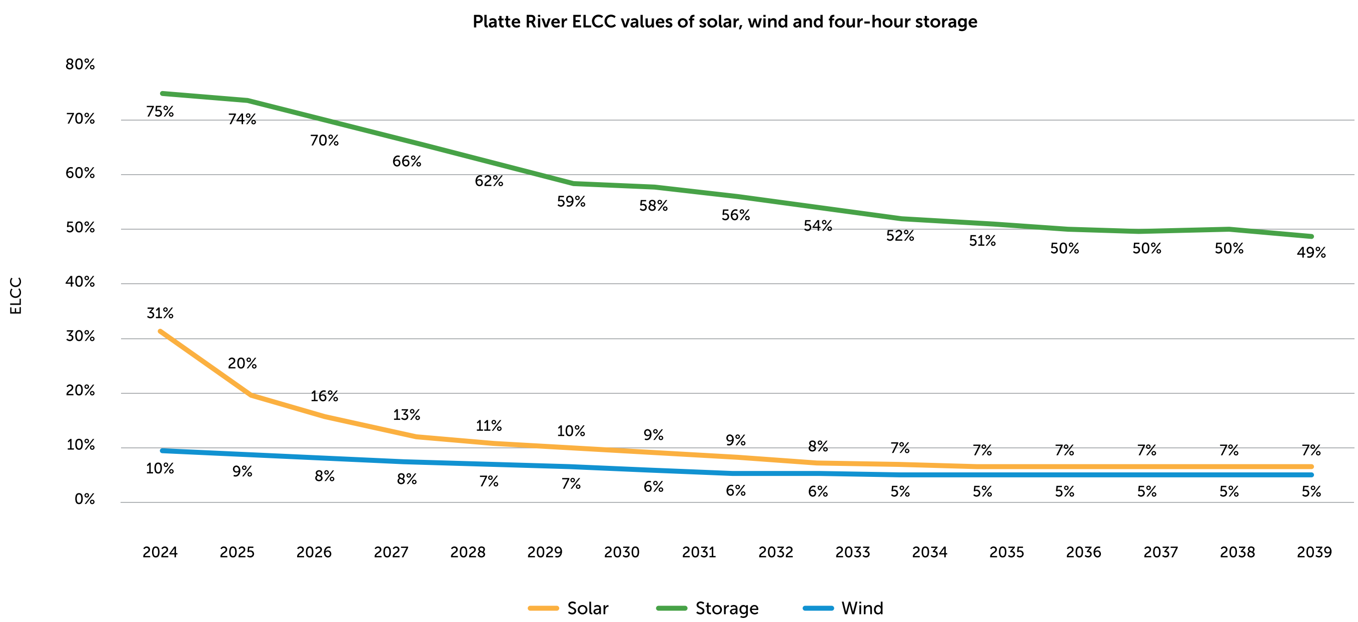



**Figure 49.** *Platte River ELCC values of solar, wind and four-hour storage*

Table 19 shows ELCC values of longer duration battery storage and some DER technologies, as computed by Astrape and used by Platte River in this IRP. The installation of more resources of the same type reduces that resource type's ELCC. For example, the ELCC of distributed solar is 8.5% if Colorado utilities install 500 MW. It drops to 5.8% with 4,000 MW installed.

| Technology | Penetration (MW) | Average ELCC (%) | Marginal ELCC (%) |
|---|---|---|---|
| 8-hour batteries | 500 | 92.7% | 91.6% |
| 8-hour batteries | 1,000 | 90.5% | 84.4% |
| 8-hour batteries | 1,500 | 87.0% | 75.6% |
| 100-hour batteries | 500 | 92.7% | 91.6% |
| 100-hour batteries | 1,000 | 91.9% | 90.8% |
| 100-hour batteries | 1,500 | 91.4% | 90.0% |
| Distributed generation solar | 500 | 8.5% | 7.9% |
| Distributed generation solar | 1,000 | 8.0% | 7.2% |
| Distributed generation solar | 2,000 | 7.2% | 5.8% |
| Distributed generation solar | 4,000 | 5.8% | 2.9% |
| Beneficial electrification | 100 | 6.9% | 7.4% |
| Beneficial electrification | 200 | 7.3% | 8.2% |
| Beneficial electrification | 300 | 7.8% | 9.0% |
| Electric vehicles | 100 | 32.0% | 33.6% |
| Electric vehicles | 200 | 33.8% | 37.3% |
| Electric vehicles | 300 | 35.7% | 41.0% |
| Demand response | 100 | 92.3% | 87.3% |
| Demand response | 200 | 87.1% | 77.8% |
| Demand response | 300 | 82.6% | 70.4% |

**Table 19.** *ELCC values of long-duration energy storage and DERs*

### 7.3.2.4 Extreme weather and dark calm modeling

Winter Storm Uri, which brought blackouts to Texas and stressed power supply across a much wider area, also impacted power supply in our area. Due to extremely cold weather for many days, demand for electricity continued to rise. Additionally, there was very little renewable generation for almost 80 hours during Feb. 12-16, 2021, as shown in Figure 50.

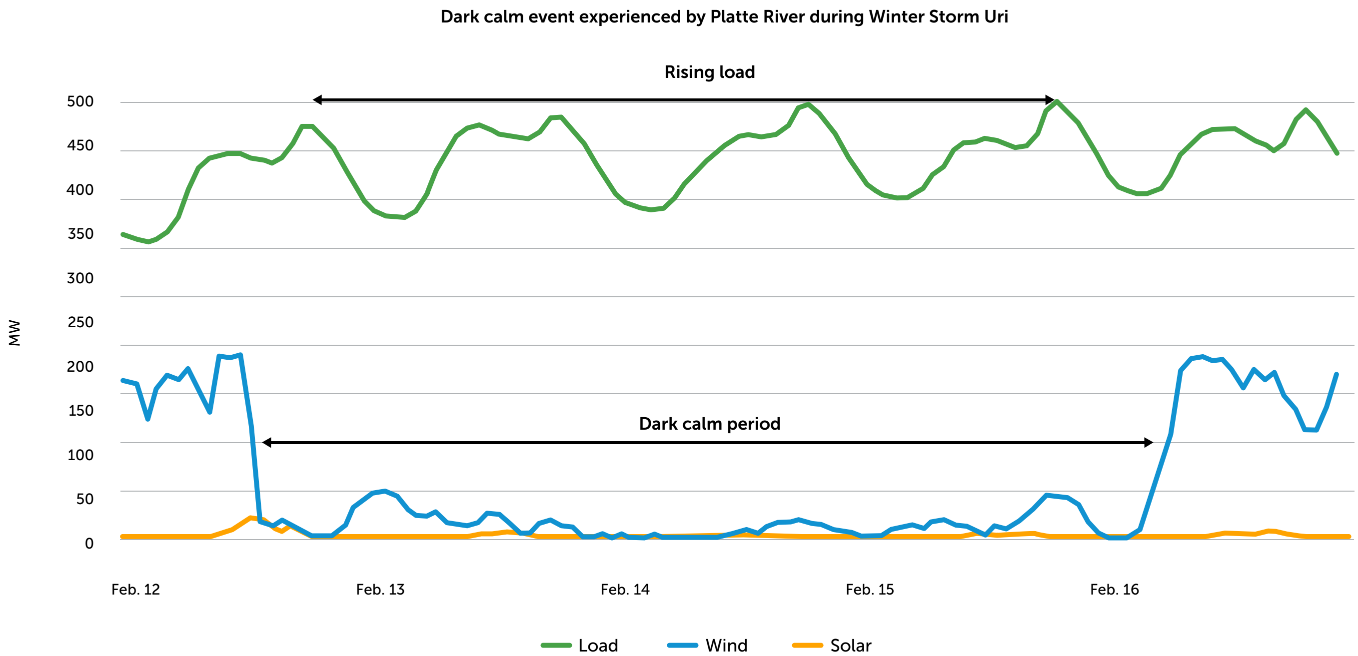



**Figure 50.** *Dark calm event experienced by Platte River during Winter Storm Uri*

During this 2021 dark calm, Platte River was able to serve its customers' load reliably because dispatchable coal resources were available. But after coal units retire in 2030, we may experience similar or even more severe dark calms. A fundamental requirement of an IRP is to develop supply portfolios that will be reliable under varying conditions of weather, previously experienced or not. This led us to hire ACES to conduct a study on extreme weather and dark calm events.[28]

ACES reviewed hourly weather profiles for 70 locations west of Mississippi for the past five decades (1973-2019) to estimate the frequency, duration and depth of extreme weather and dark calm events. Since these events are uncommon, ACES reviewed weather data across a wide region and over a long period of time to enhance confidence in the findings. Figure 51 shows locations of the airports where data was collected.

[28] https://www.prpa.org/wp-content/uploads/2023/04/2024IRP-Extreme-weather-events-and-Dark-Calm-Analysis-by-ACES.pdf In 2022, Platte River filed a voluntary CEP with the state of Colorado, laying out a plan to reduce its greenhouse gas emissions by at least 80% by 2030 (compared to a 2005 base line).

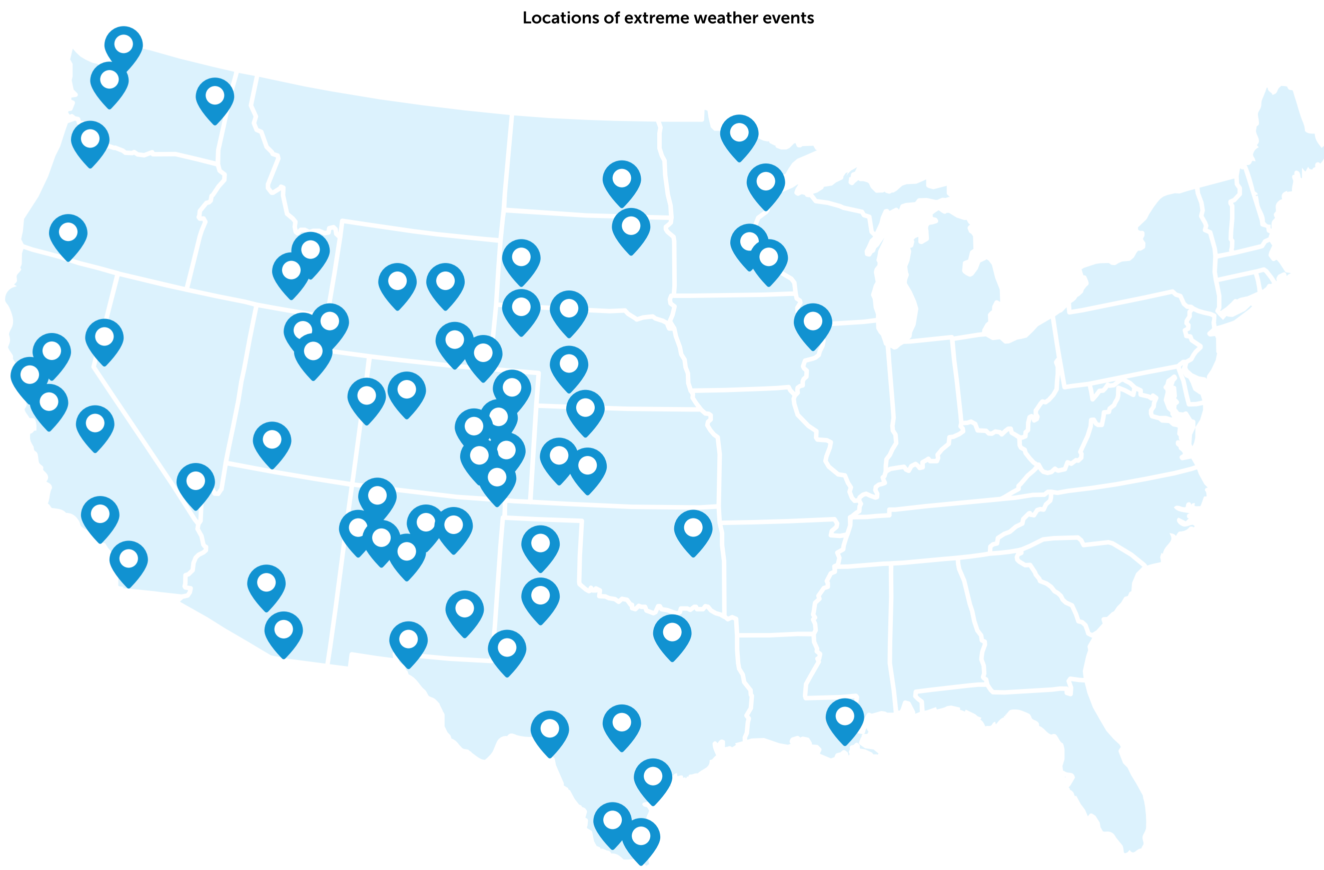



**Figure 51.** *Locations of extreme weather events*

## 7.3.2.5 Extreme weather events

The study found the following durations and frequencies of heat and cold waves:

| Heat wave summary – west region | | | | | | |
|---|---|---|---|---|---|---|
| Number of hours | 48 | 72 | 96 | 120 | 144 | 168 |
| Events per year | 0.47 | 0.02 | 0.09 | 0.04 | 0.021 | 0.043 |

**Table 20.** *Heat wave summary - west region*

This means every other year, there is a heat wave lasting two days and every 11th year, there is a heat wave lasting four days.

| Cold wave summary – west region | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Number of hours | 48 | 72 | 96 | 120 | 144 | 168 | 192 | 216 | 240 | 264 | 288 | 312 | 336 |
| Events per year | 4.9 | 1.7 | 0.9 | 0.4 | 0.17 | 0.08 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Table 21.** *Cold wave summary - west region*

This data shows cold waves are more common with five two-day events every year and a weeklong event almost every 12th year.

The study also found that load, power and gas prices rise during these extreme events and noted these increases during winter storms Uri and Elliot and the 2020 summer heat wave in the Pacific Northwest. Because our focus with extreme weather modeling is on reliability, we assessed how extreme weather impacts load only. The study found that during these events, on average, the load could increase by about 10% relative to the normal load for that time of year. So, for reliability assessments during extreme weather, we increased the hourly load by 10%.

## 7.3.2.6 Dark calm events

Frequency and duration of dark calm events was assessed for the MISO North , covering parts of Illinois, Indiana, Wisconsin and Michigan; MISO Central, covering parts of Minnesota, Iowa and North Dakota; and the Northwest portion of the Electric Reliability Council of Texas (ERCOT. Table 22 shows the frequency and duration of different levels of dark calm events.

| Dark calm events by location | | | | |
|---|---|---|---|---|
| % of full output | 48 hours | 72 hours | 96 hours | 120 hours |
| MISO Central | | | | |
| 5% | 3.0 | 1.25 | 0.5 | 0.25 |
| 10% | 11.2 | 5.6 | 2.4 | 2.0 |
| 15% | 6.2 | 11.4 | 3.8 | 4.8 |
| MISO North | | | | |
| 5% | 1.0 | 1.0 | 0.67 | 0.0 |
| 10% | 5.0 | 1.75 | 0.5 | 1.0 |
| 15% | 2.2 | 3.0 | 1.2 | 2.0 |
| Northwest ERCOT | | | | |
| 10% | 3.8 | 1.0 | 0.2 | 0.2 |
| 15% | 3.2 | 3.4 | 3.0 | 1.2 |

**Table 22.** *Dark calm events by location*

As shown in Table 22, a dark calm event in MISO Central, where the output of renewable drops to 5% of total generation occurs:

- Three times during the year for two days every year
- Once per year for three consecutive days
- Every other year for four consecutive days
- Every four years for five consecutive days

Dark calm events where output of renewables drops to 10% of total generation are more frequent than events where renewable generation is only 5% of total generation. Dark calm events are less intense and less frequent in MISO North and Northwest ERCOT.

In the Plexos model, we averaged the two 5% rows for MISO Central and MISO North. Multiplying the probability of an event's occurrence with its duration yields the expected outage hours in a given year for that event. For example, as illustrated in Table 23, an average of two events with a duration of 48 hours means any given year would expect a total of 96 dark calm hours because the events last two days.

Since the events are non-additive, we sum all the expected hours to find the total expected dark calm hours in a year. In this case, an average year would see a total of 248 hours of dark calm spread across events of different durations.

| Dark calm duration (hours) | 48 | 72 | 96 | 120 | Total dark calm hours |
|---|---|---|---|---|---|
| Average # of dark calm events across all regions (5% of full output) | 2.000 | 1.125 | 0.585 | 0.125 | |
| Expected dark calm hours per year | 96 | 81 | 56.16 | 15 | **248.16** |

**Table 23.** *Dark calm event duration and frequency*

## 7.3.2.7 Transmission planning

Platte River conducts annual transmission assessment studies to plan for a system that adequately supports both short and long-term load obligations to the owner communities. The studies use transmission network modeling software and integrate forecasted owner community loads, existing and planned generation, and loads and generation from neighboring utilities.

Short-term studies evaluate system needs under the current transmission network configuration, integrating projected short-term load and generation forecasts. Evaluating long-term transmission needs includes forecasting long-term load and generation forecasts with both the current transmission system and planned transmission additions.

The study objectives are for the transmission system to perform reliably during extreme contingency situations, heavy or light load conditions and fault events. If a study identifies network deficiencies, further analysis follows to determine network expansion options to mitigate those deficiencies. Transmission studies are conducted during annual internal assessment activities, along with collaborative studies with regional transmission planning committees.

### 7.3.3 Need for new resources

As explained in chapter 5, we forecast our future energy needs as annual peak demand (maximum demand in any hour) and total annual energy for every hour of the year. For supply-side planning, we adjust these values with DER contribution from our customers. The net peak demand and energy demand are what Platte River needs to plan for through this IRP process. As discussed earlier in this chapter, Platte River plans to meet its future peak demand with 19.9% PRM to protect supply reliability. We also discussed that renewable and energy limited resources contribute less ELCC capacity toward the peak demand than their maximum or nameplate capacity.

Figure 52 shows the capacity requirements and capacity contributions from the existing and committed resources.

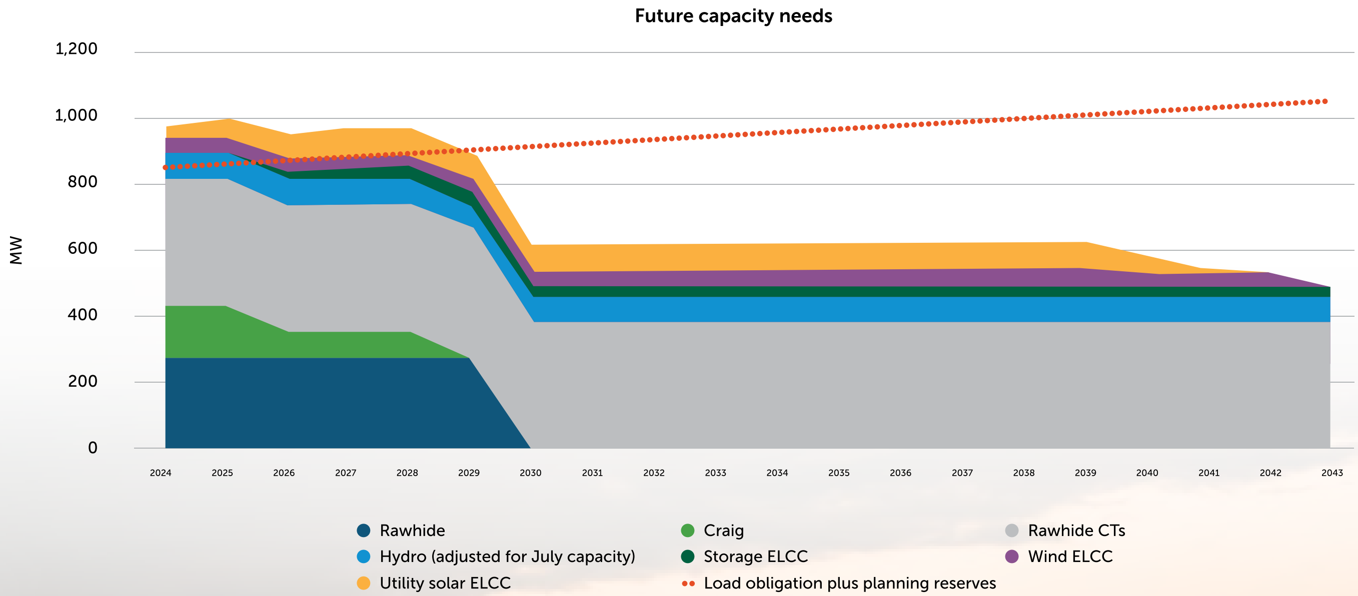



**Figure 52.** *Future capacity needs*

The dotted red line shows capacity requirements, while the area chart shows the capacity available. By 2029, following the retirements of Craig coal units, Platte River would need to build some new capacity, and by 2030, with the retirement of Rawhide coal plant, the additional capacity requirement rises to about 200 MW. The gap continues to expand as our load continues to increase and when our existing wind and solar PPAs reach their maturation dates. The IRP process offers recommendations to fill this gap with the lowest cost, least-emitting reliable resources.

Figure 53 shows similar chart depicting the energy deficit that will need to be filled in this IRP. Note small changes in renewable energy from year to year are due to projected changes in excess or "dumped" renewable generation.

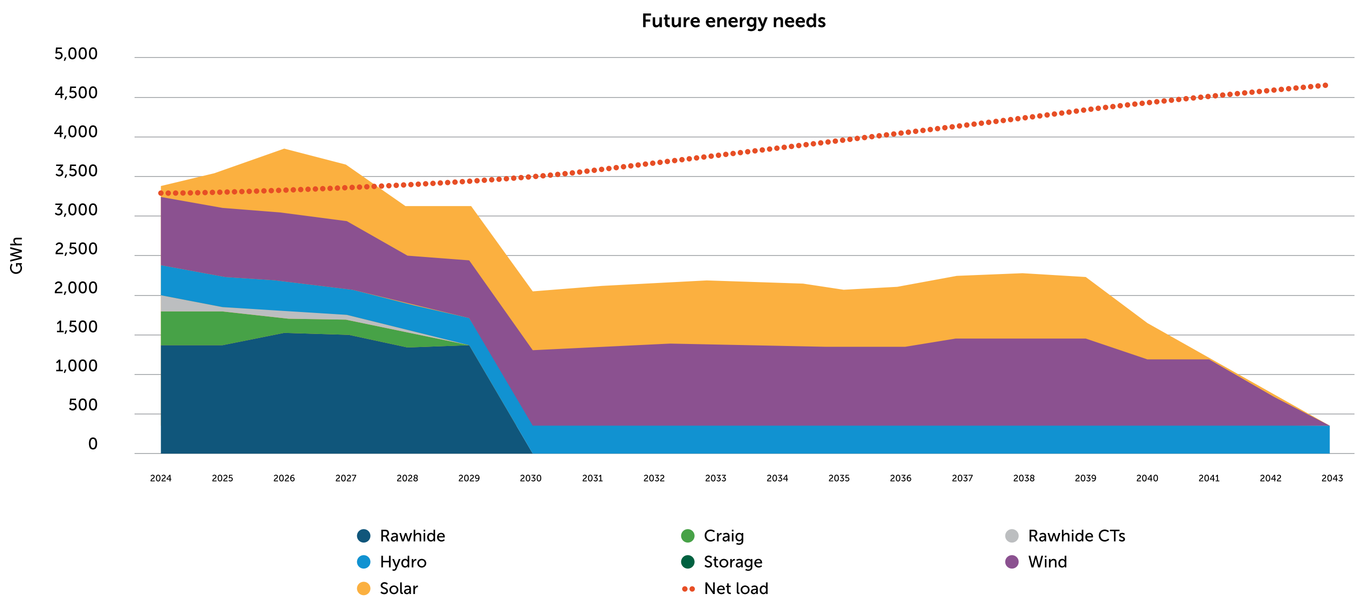



**Figure 53.** *Future energy needs*

Although capacity and energy gaps appear in 2030, Platte River plans to bring new resources online before 2030. This would give us time to test the availability and reliability of our new portfolio before retiring the last coal plant by the end of 2029.

## 7.4 Future portfolios

The portfolios selected for this IRP are designed to capture the range of potential paths available to Platte River as it transforms its generation portfolio and strives to meet the RDP goal. Reliability is the only firm constraint common to all portfolios. Other financial, operational and environmental metrics are optimized within the unique constraints of each portfolio.

Due to PRM requirements and to support reliability during dark calm events, Platte River keeps its existing combustion turbines in all portfolios. All portfolios emit some CO2 in 2030 because dispatchable noncarbon options will not be available by 2030, so thermal units are dispatched to balance the system during shortages. Portfolios that build new dispatchable thermal generation assume a blend 50% green hydrogen fuel by 2035 to reduce CO2 emissions. All dispatchable thermal generation is assumed to switch to 100% green hydrogen by 2040 and reach zero CO2 emissions. No new dispatchable thermal generation is allowed after 2030 and the IRP assumes long-duration energy storage becomes available in 2035. All portfolios assumed that future electricity prices  would also include carbon taxes. Below is a brief description of all the portfolios.

### 7.4.1 No new carbon

In this portfolio, Platte River cannot add new thermal generation. Wind, solar and four-hour storage are the only new resource additions available until 2035, when long-duration energy storage is assumed to also become available. This portfolio is designed to test the feasibility of relying on the existing combustion turbines to maintain reliability, without adding new thermal generation.

### 7.4.2 Minimal new carbon

This portfolio is built to add minimal amount of new thermal generation. It adds only 80 MW of new dispatchable thermal generation.

### 7.4.3 Carbon-imposed cost

This portfolio is built with the cost of carbon assigned to the dispatch cost of all thermal units. This additional cost, assigning a dollar value to the externalities associated with emitting CO2, disincentivizes the construction and use of carbon-emitting resources unless it is more cost effective than other options after accounting for the social cost of carbon. Specifically, this is a least-cost portfolio where the assumed cost carbon emissions have been internalized into the optimization process.

### 7.4.4 Optimal new carbon

This portfolio is a balance between the additional new carbon and carbon-imposed cost portfolios in terms of reliability and cost, building 200 MW of new thermal generation. This portfolio is optimal to support reliability in all conditions, as dark calm and extreme weather events continue to become more severe, as they have in the recent past.

### 7.4.5 Additional new carbon

This portfolio is the result of a least-cost optimization. The model builds the lowest-cost portfolio that meets reliability standards, but adds no additional constraints to guide resource selection or operation.

## 7.5 Methodology

Developing future power supply portfolios is a multi-step, iterative process. Figure 54 illustrates the initial steps and the subsequent iteration through the remaining steps.

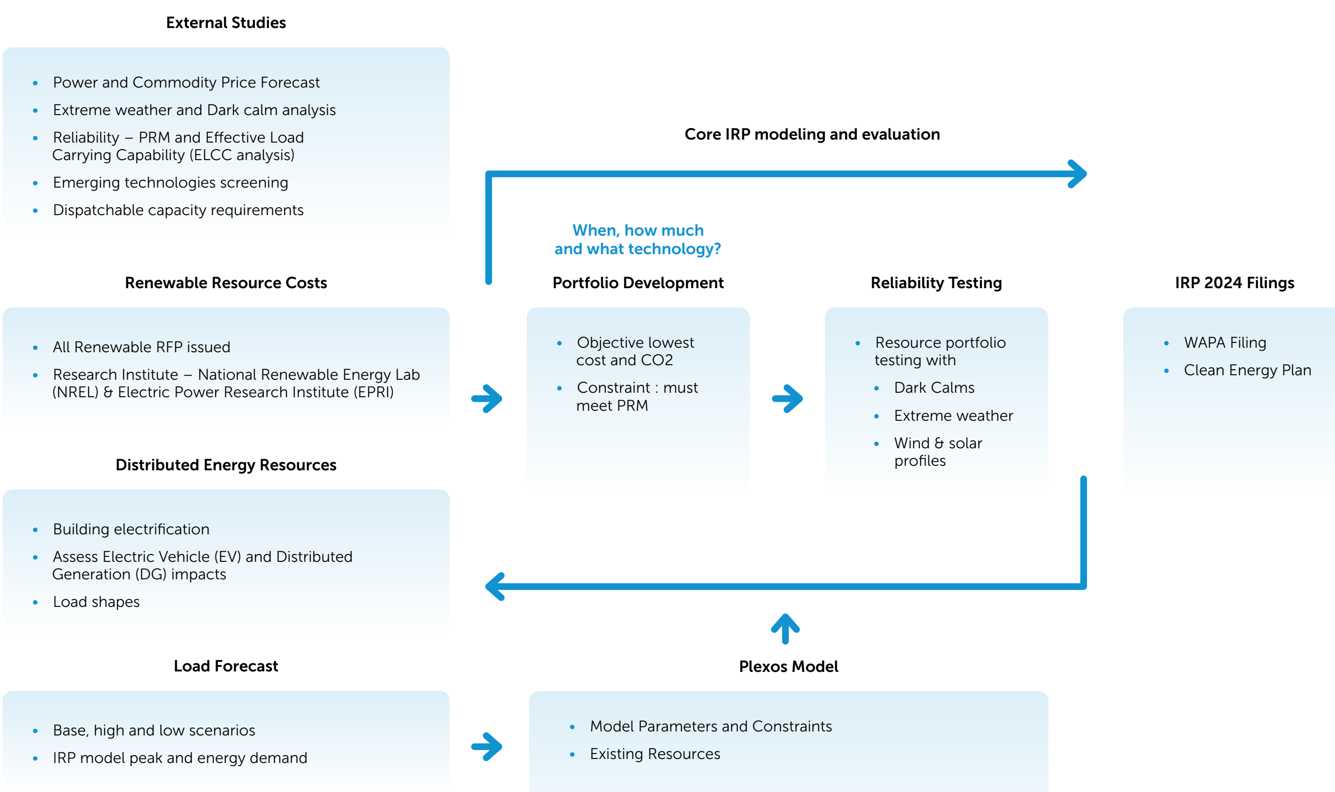



**Figure 54.** *IRP process*

## 7.5.1 Multi-step portfolio selection methodology

**Data collection and review:** Gather data on existing resources, including their performance and their expected operational lives; develop power and fuel price forecasts; review existing and potential future environmental regulations. These results provide a first step in understanding the planning landscape for the IRP.

**Demand forecasting:** Estimate future electricity demand, considering factors such as population growth, economic trends and technological advancements to project the energy needs over the planning horizon.

**DER forecasting:** Forecast new sources of demand, such as beneficial electrification and electric vehicles as well as additional demand-side resources, including customer-sited storage, rooftop solar, demand response and other programs.

**Technology assessment:** Evaluate the performance, costs, and environmental impacts of various energy technologies, including renewable energy sources, dispatchable thermal resources and energy storage. Based on the results of this high-level evaluation, Platte River can eliminate some technologies from consideration.

**Stakeholder engagement:** Collect feedback from a broad range of stakeholders. Community members, local businesses and advocacy

organizations are invited to offer their ideas and raise any concerns they have with the IRP process. This collaborative approach helps portfolios reflect the range of interests and priorities in the communities we serve.

## 7.5.2 Portfolio iterations

**Optimization modeling:** Use Plexos to develop and evaluate different portfolios of energy resources. Each portfolio is the result of a unique mix of inputs and constraints designed to test different aspects of the planning criteria, such as financial sustainability or environmental responsibility.

**Reliability testing:** Conduct reliability testing to identify uncertainties and potential challenges associated with different resource options. With high penetration of variable generation, the most critical risk tests quantify the system's exposure to dark calms or extreme weather. Platte River also reviews potential challenges associated with excessive energy length (too much energy produced compared to load) in a region expected to add substantial amounts of renewable energy in the future.

**Sensitivity analysis:** Explore how different external factors, such as fuel and market prices or emissions, might influence the performance of the portfolios. This helps develop plans that should be resilient under a range of future outcomes.

## 7.6 Reliability testing of portfolios

Because reliability is a foundational pillar, we first make sure each candidate portfolio is sufficiently reliable. As a starting point, a least-cost portfolio is developed to fill the capacity and energy gaps identified above while meeting the PRM requirement for every year of the planning horizon. Meeting the annual PRM requirement while applying the ELCC to energy-limited resources is useful, but does not test or guarantee reliability during extreme weather events or dark calms. So we conducted additional reliability testing through the Monte Carlo functionality in Plexos to understand how the portfolios might behave under stress conditions. Using the data from the extreme weather report supplied by ACES and historical weather data from Vaisala, we modeled different system conditions with the following variables:

1. **Weather:** Wind and solar profiles reflecting conditions from 1997-2019 (hourly profiles for 24 years), drawn with equal probability across the suite of simulations. In our runs, with 504 iterations, each weather year was experienced 21 times.

2. **Thermal unit outages:** The software randomly draws the timing of thermal unit outages. The duration of outages is also hypothetical, but the software does align the random outages with the known long-term forced outage rate over the course of many draws.

3. **Load forecast error:** Each iteration simulated a potential deviation from the near-term load forecast. This represents a shift in load drivers, such as population changes or economic indicators, over the one-to-four-year horizon, which is too short for the utility to respond to. The system, as built, would need to cover these near-term divergences before new resources could be brought online in response. For this IRP, Table 24 summarizes the potential load forecast error outcomes.

| LFE | Probability |
|---|---|
| -4% | 7.26% |
| -2% | 24.10% |
| 0% | 37.28% |
| 2% | 24.10% |
| 4% | 7.26% |

**Table 24.** *Potential load forecast error outcomes*

4. **Dark calm events:** Based on observed historical events, the model simulated weather events with impacts on both load and weather-dependent generation. These events could last between one and five days, with a two-day event being the most common. Often, dark calm events occur with extreme weather events. In any year, the system would expect to experience a total of 248 hours of extreme weather conditions distributed across several events. As with thermal outages, specific years could experience higher or lower than average dark calm outages with the long-term average converging to the expected value over may iterations. Across all 504 iterations of our reliability modeling, the dark calm hours in a year varied from a low of 119 hours to a high of 458 hours. Specific details on the impact to wind, solar and load are described below.

    a. **Load:** Load is modeled to increase by 10% during the event, which is consistent with data seen in other regions during extreme weather events. This is primarily driven by increased heating load during winter storms while cooling load is expected to increase during heat dome events in the summer. This increase captures the load already embedded in the load forecast.

    b. **Building heating:** During extreme winter storms, some new load from heat pumps is expected to shift to much less efficient electrical resistance heating as temperatures drop below their operating ranges. This increase in load is captured individually and is quantified by the consultant who supplied the beneficial electrification forecast.

    c. **Solar:** During the winter months, solar generation during a dark calm averages 5% of its nameplate. These generators can experience a variety of issues including snow cover or icing, overcast skies or debris or dust buildup due to high winds. In the summer months, solar output during a dark calm event averages 10% because summer outages are often caused by extended overcast weather.

    d. **Wind:** During the winter months, wind generation during a dark calm averages 5% of its nameplate. This reduced production is primarily due to blade icing, but overspeed (wind too strong to safely operate turbines) also drives some outages. In the summer months, output during a dark calm event also averages 5%, as summer wind droughts, especially during heat dome events, are common.

## 7.7 Modeling tool

Platte River used the Plexos simulation and modeling tool for the 2024 IRP. Plexos is an economic dispatch and capacity expansion model developed by Energy Exemplar (www.energyexemplar.com).

# 08
# IRP study results

This chapter presents the modeling results for each portfolio, with comparisons of their most important metrics including cost, CO2 emission reductions and renewable energy penetration—metrics that align with Platte River's foundational pillars of financial sustainability and environmental responsibility. As noted previously, every portfolio considered in this IRP meets our reliability criteria (another foundational pillar).

## 8.1 Summary of five portfolios

Every portfolio assumed a common starting point of existing resources plus new, near-term resource additions from recently signed agreements and solicitations under development. These are considered "committed" resources and the IRP process considers them "given," just like existing resources. These near-term additions represent Platte River's best estimate of solicitation results. In the current environment, project timelines, pricing and size are uncertain and subject to change. Platte River remains flexible and will adjust future capacity acquisitions to compensate for changes to current acquisitions.

## 8.1.1 Load forecast with DER assumptions

Customer load and DER projections for all the portfolios are similar. Therefore, the various portfolios primarily represent different supply-side options. Load forecast and DER projections are discussed in detail in chapter 5. Figures 37 and 38 in Chapter 5 show annual peak and energy forecasts and DER impact through the planning period. Figures 55 and 56 illustrate annual peak and energy forecasts for quick reference.

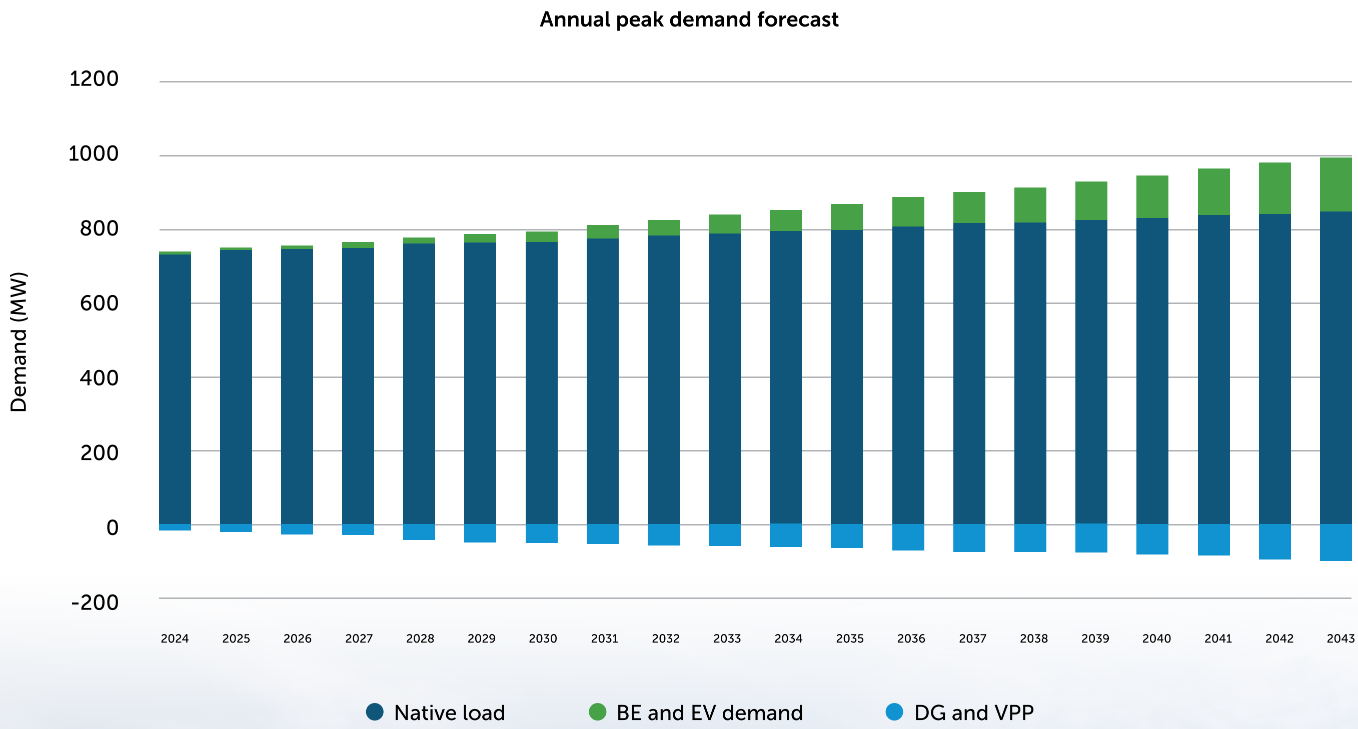



**Figure 55.** *Annual peak demand forecast*

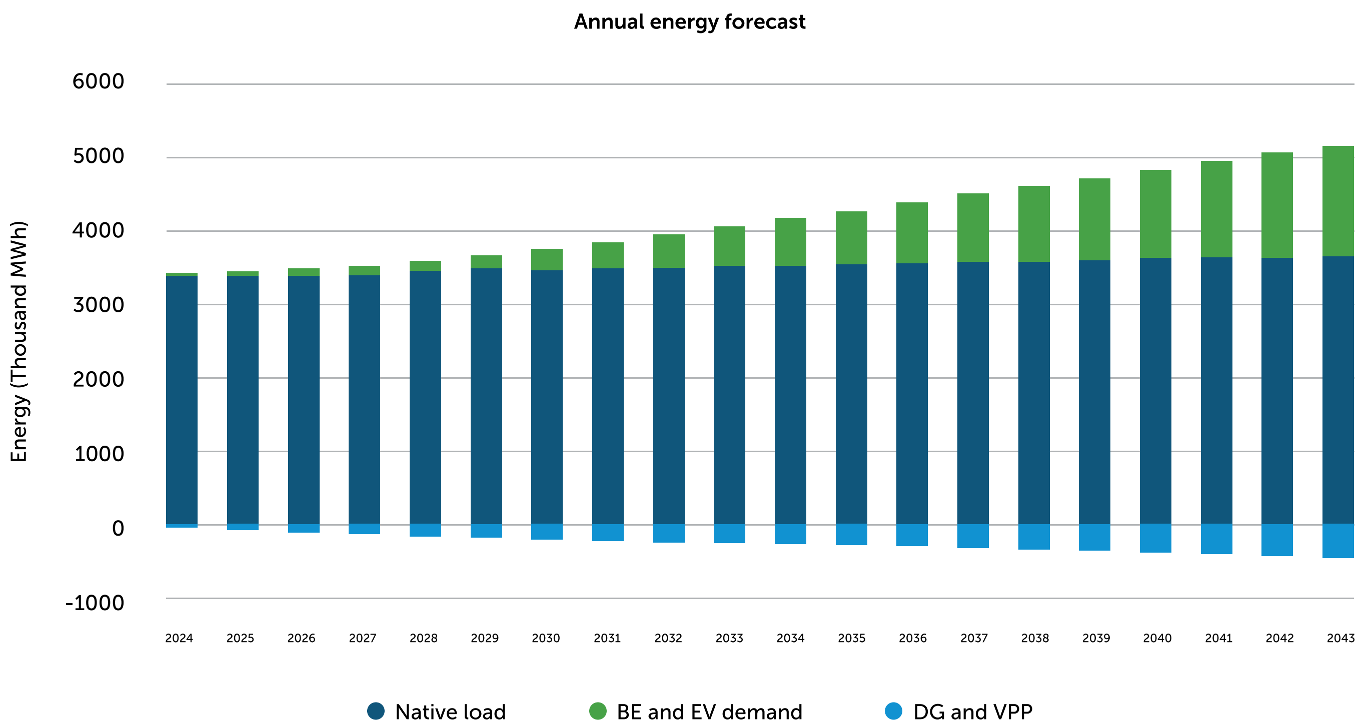



**Figure 56.** *Annual energy forecast*

Figures 55 and 56 illustrate that DERs are projected to grow much faster than the base load. Distributed generation, which is largely rooftop solar, reduces base peak load by 7% in 2030 and 10% by 2040. The growth of building beneficial electrification and EVs is even faster. Together, these add about 8% to the annual energy demand by 2030 and 34% by 2040.

Table 25 summarizes the utility-scale resources common to all portfolios before Platte River developed and optimized its expansion plans. As described in earlier sections, there are also DER resources embedded in every portfolio that are not subject to optimization during the modeling process.

| | Existing resources MWs | Near-term solicitation MWs | Total MWs |
|---|---|---|---|
| Wind | 231 | 250 | 481 |
| Solar | 52 | 300 | 352 |
| Battery energy storage systems | 1 | 50 | 51 |
| Long-duration storage | 0 | 10 | 10 |

**Table 25.** *Existing and committed resources*

Additionally, the following assumptions are common to all the portfolios:

- No new thermal generation is constructed after 2030 and all subsequent resource additions will be noncarbon-emitting resources.
- Long-duration energy storage technology is available from 2035 onwards.
- New thermal generation uses a fuel blend containing 50% green hydrogen from 2035 onwards.
- All thermal generation uses 100% green hydrogen fuel from 2040 onwards, eliminating CO2 emissions.

The portfolios developed in this IRP cover a broad range of potential pathways Platte River might consider as it decarbonizes its power supply portfolio. We are committed to completely retire coal generation by the end of 2029 so the expansion plans include aggressively adding renewable energy. Each portfolio adds 600-800 MW of new renewable energy capacity, although the mix between wind and solar may be different in each portfolio as the optimization seeks to minimize cost while meeting reliability metrics.

Platte River also models additional thermal units and storage to complement its renewable energy acquisitions and comply with reliability criteria. The main differences between the portfolios are the choices about adding thermal resources and storage.

Table 26 summarizes the resources added during the resource acquisition period, as well as the final buildout at the end of the planning horizon in 2043. Note the solar and wind energy additions closely converge by 2043, with only a 100 MW capacity spread between the highest and lowest additions. This is because all portfolios depend heavily on renewable energy, with thermal energy largely acting as a reliability backstop.

| | No new carbon | Minimal new carbon | Carbon-imposed cost | Optimal new carbon | Additional new carbon (lowest cost) |
|---|---|---|---|---|---|
| **2024-2029 incremental additions (MWs)** | | | | | |
| Wind | 300 | 300 | 400 | 400 | 300 |
| Solar | 450 | 500 | 350 | 300 | 300 |
| Four-hour storage | 2,850 | 1,050 | 275 | 175 | 100 |
| Long-duration storage | 10 | 10 | 10 | 10 | 10 |
| Dispatchable thermal | 0 | 80 | 160 | 200 | 240 |
| **Final 2043 Portfolio (MWs)** | | | | | |
| Wind | 885 | 885 | 985 | 885 | 985 |
| Solar | 600 | 600 | 550 | 600 | 450 |
| Four-hour storage | 2,850 | 1,100 | 400 | 275 | 175 |
| Long-duration storage | 10 | 160 | 10 | 160 | 110 |
| Dispatchable thermal | 0 | 80 | 160 | 200 | 280 |

**Table 26.** *Summary of five portfolios*

Additional detailed tables are provided in the following section for each portfolio, showing annual capacity additions by each category, further divided into new and existing resources.

## 8.2 Individual portfolio details

In this section we describe notable features of each portfolio and show the 20-year projections for each by year and by resource type.

### 8.2.1 No new carbon portfolio

This portfolio does not add any new thermal generation but continues to operate the existing natural gas CTs at Rawhide. To serve its future energy and reliability needs, Platte River adds an incremental 300 MW of wind and 450 MW of solar. To maintain reliability, the portfolio relies on four-hour battery storage with a total addition of 2,850 MW by 2029.

The substantial buildout of four-hour storage in the early years eliminates the need for additional storage during the planning period. Table 27 shows annual resource additions over the planning horizon for this portfolio.

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 431 | 431 | 354 | 354 | 354 | 280 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 81 | 78 | 75 | 72 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| Frame units (existing) | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 |
| Aeroderivative units (new) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 30 | 0 | 0 |
| Solar (new) | 0 | 150 | 300 | 300 | 450 | 450 | 450 | 450 | 500 | 500 | 500 | 500 | 500 | 550 | 600 | 700 | 550 | 450 | 550 | 600 |
| Wind | 231 | 231 | 231 | 231 | 231 | 231 | 231 | 291 | 291 | 291 | 285 | 285 | 285 | 285 | 285 | 285 | 225 | 225 | 225 | 0 |
| Wind (new) | 0 | 0 | 0 | 200 | 300 | 300 | 360 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 400 | 400 | 560 | 660 | 660 | 885 |
| Storage 4-hr | 2 | 2 | 27 | 52 | 1452 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2852 | 2850 | 2850 | 2850 | 2850 |
| Storage LT | 0 | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Solar DER | 46 | 62 | 83 | 105 | 126 | 141 | 155 | 169 | 180 | 190 | 200 | 210 | 223 | 236 | 251 | 266 | 282 | 299 | 318 | 337 |
| Storage DER | 3 | 6 | 10 | 17 | 24 | 32 | 39 | 47 | 54 | 63 | 70 | 76 | 82 | 86 | 90 | 94 | 101 | 108 | 115 | 123 |
| **Total** | **1234** | **1399** | **1520** | **1772** | **3457** | **4806** | **4607** | **4628** | **4698** | **4716** | **4827** | **4843** | **4861** | **4929** | **4997** | **5117** | **5088** | **5090** | **5186** | **5263** |

**Table 27.** *No new carbon portfolio annual resource additions (in MW)*

### 8.2.2 Minimal new carbon portfolio

This portfolio allows only 80 MW of new thermal generation. Due to this constraint, this portfolio requires a substantial amount of four-hour storage by 2030, as much as 1,050 MW. This portfolio also adds 300 MW of wind and 500 MW of solar by 2030. This is the most additional solar among all the portfolios, complementing the four-hour storage needed to cover daily peaks. After 2030, more wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 28 shows annual resource additions over the planning horizon for this portfolio.

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 431 | 431 | 354 | 354 | 354 | 280 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 81 | 78 | 75 | 72 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| Frame units (existing) | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 |
| Aeroderivative units (new) | 0 | 0 | 0 | 0 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Solar | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 30 | 0 | 0 |
| Solar (new) | 0 | 150 | 300 | 300 | 450 | 500 | 500 | 500 | 500 | 500 | 550 | 550 | 600 | 700 | 700 | 750 | 600 | 500 | 600 | 600 |
| Wind | 231 | 231 | 231 | 231 | 231 | 231 | 231 | 291 | 291 | 291 | 285 | 285 | 285 | 285 | 285 | 285 | 225 | 225 | 225 | 0 |
| Wind (new) | 0 | 0 | 0 | 200 | 300 | 300 | 360 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 400 | 560 | 660 | 660 | 885 |
| Storage 4-hr | 2 | 2 | 27 | 52 | 552 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1052 | 1050 | 1050 | 1075 | 1100 |
| Storage LT | 0 | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 60 | 60 | 60 | 110 | 110 | 110 |
| Solar DER | 46 | 62 | 83 | 105 | 126 | 141 | 155 | 169 | 180 | 190 | 200 | 210 | 223 | 236 | 251 | 266 | 282 | 299 | 318 | 337 |
| Storage DER | 3 | 6 | 10 | 17 | 24 | 32 | 39 | 47 | 54 | 63 | 70 | 76 | 82 | 86 | 90 | 94 | 101 | 108 | 115 | 123 |
| **Total** | **1234** | **1399** | **1520** | **1772** | **2637** | **3136** | **2937** | **2958** | **2978** | **2996** | **3057** | **3173** | **3241** | **3359** | **3427** | **3497** | **3468** | **3520** | **3641** | **3693** |

**Table 28.** *Minimal new carbon portfolio annual resource additions (in MW)*

### 8.2.3 Carbon-imposed cost portfolio

The carbon-imposed cost attempts to measure the economic and environmental cost of CO2 for society. Due to the increased cost for CO2 emissions, this portfolio limits the addition of new dispatchable thermal units to 160 MW and favors four-hour battery storage, with 275 MW of new capacity. As with other plans, wind and solar are the primary energy sources, with 400 MW of new wind and 350 MW of new solar by 2030. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 29 shows annual resource additions over the planning horizon for this portfolio.

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 431 | 431 | 354 | 354 | 354 | 280 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 81 | 78 | 75 | 72 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| Frame units (existing) | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 |
| Aeroderivative units (new) | 0 | 0 | 0 | 0 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 |
| Solar | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 30 | 0 | 0 |
| Solar (new) | 0 | 150 | 300 | 300 | 300 | 350 | 350 | 350 | 400 | 450 | 450 | 450 | 450 | 450 | 450 | 500 | 450 | 450 | 500 | 550 |
| Wind | 231 | 231 | 231 | 231 | 231 | 231 | 231 | 291 | 291 | 291 | 285 | 285 | 285 | 285 | 285 | 285 | 225 | 225 | 225 | 0 |
| Wind (new) | 0 | 0 | 0 | 200 | 400 | 400 | 460 | 400 | 400 | 400 | 400 | 500 | 500 | 500 | 600 | 600 | 660 | 760 | 760 | 985 |
| Storage 4-hr | 2 | 2 | 27 | 52 | 127 | 277 | 277 | 302 | 327 | 352 | 377 | 377 | 377 | 377 | 377 | 377 | 375 | 375 | 375 | 400 |
| Storage LT | 0 | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 60 | 60 | 60 | 60 | 60 | 110 | 160 | 160 | 160 |
| Solar DER | 46 | 62 | 83 | 105 | 126 | 141 | 155 | 169 | 180 | 190 | 200 | 210 | 223 | 236 | 251 | 266 | 282 | 299 | 318 | 337 |
| Storage DER | 3 | 6 | 10 | 17 | 24 | 32 | 39 | 47 | 54 | 63 | 70 | 76 | 82 | 86 | 90 | 94 | 101 | 108 | 115 | 123 |
| **Total** | **1234** | **1399** | **1520** | **1772** | **2242** | **2391** | **2192** | **2238** | **2333** | **2426** | **2462** | **2628** | **2646** | **2664** | **2782** | **2852** | **2873** | **3025** | **3071** | **3173** |

**Table 29.** *Carbon-imposed cost portfolio annual resource additions (in MW)*

### 8.2.4 Optimal new carbon portfolio

This portfolio adds 200 MW of new dispatchable thermal resources and 175 MW of new battery storage as it balances capacity support across both thermal and batteries. Like the carbon-imposed cost portfolio, this portfolio adds 400 MW of wind but slightly less solar, with 300 MW of new capacity by 2030. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 30 shows annual resource additions over the planning horizon for this portfolio.

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 431 | 431 | 354 | 354 | 354 | 280 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 81 | 78 | 75 | 72 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| Frame units (existing) | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 |
| Aeroderivative units (new) | 0 | 0 | 0 | 0 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| Solar | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 30 | 0 | 0 |
| Solar (new) | 0 | 150 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 400 | 450 | 450 | 450 | 550 | 600 |
| Wind | 231 | 231 | 231 | 231 | 231 | 231 | 231 | 291 | 291 | 291 | 285 | 285 | 285 | 285 | 285 | 285 | 225 | 225 | 225 | 0 |
| Wind (new) | 0 | 0 | 0 | 200 | 400 | 400 | 460 | 400 | 400 | 400 | 400 | 500 | 500 | 500 | 600 | 600 | 660 | 660 | 660 | 885 |
| Storage 4-hr | 2 | 2 | 27 | 52 | 102 | 177 | 177 | 202 | 227 | 252 | 252 | 252 | 252 | 252 | 252 | 252 | 250 | 250 | 250 | 275 |
| Storage LT | 0 | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 60 | 60 | 60 | 60 | 60 | 110 | 160 | 160 | 160 |
| Solar DER | 46 | 62 | 83 | 105 | 126 | 141 | 155 | 169 | 180 | 190 | 200 | 210 | 223 | 236 | 251 | 266 | 282 | 299 | 318 | 337 |
| Storage DER | 3 | 6 | 10 | 17 | 24 | 32 | 39 | 47 | 54 | 63 | 70 | 76 | 82 | 86 | 90 | 94 | 101 | 108 | 115 | 123 |
| **Total** | **1234** | **1399** | **1520** | **1772** | **2257** | **2281** | **2082** | **2128** | **2173** | **2216** | **2327** | **2493** | **2511** | **2529** | **2647** | **2717** | **2788** | **2840** | **2936** | **3038** |

**Table 30.** *Optimal new carbon portfolio annual resource additions (in MW)*

### 8.2.5 Additional new carbon portfolio

The primary objective of this portfolio is to minimize costs. To do so, this portfolio relies on 240 MW of new dispatchable thermal resources to provide firm capacity. Renewables still supply most of the energy, with 300 MW of new wind and 300 MW of new solar by 2030. To help manage the renewable energy, this portfolio adds 100 MW of storage. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 31 shows annual resource additions over the planning horizon for this portfolio.

|  | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal | 431 | 431 | 354 | 354 | 354 | 280 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 81 | 78 | 75 | 72 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 |
| Frame units (existing) | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 | 388 |
| Aeroderivative units (new) | 0 | 0 | 0 | 0 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 240 | 280 | 280 | 280 |
| Solar | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 30 | 0 | 0 |
| Solar (new) | 0 | 150 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 350 | 350 | 350 | 350 | 400 | 400 | 350 | 400 | 450 |
| Wind | 231 | 231 | 231 | 231 | 231 | 231 | 231 | 291 | 291 | 291 | 285 | 285 | 285 | 285 | 285 | 285 | 225 | 225 | 225 | 0 |
| Wind (new) | 0 | 0 | 0 | 200 | 300 | 300 | 360 | 300 | 300 | 300 | 500 | 500 | 500 | 600 | 600 | 600 | 660 | 760 | 760 | 985 |
| Storage 4-hr | 2 | 2 | 27 | 52 | 52 | 102 | 102 | 102 | 127 | 152 | 152 | 152 | 152 | 152 | 152 | 152 | 150 | 150 | 150 | 175 |
| Storage LT | 0 | 0 | 0 | 0 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 60 | 60 | 60 | 60 | 60 | 110 | 110 | 110 | 110 |
| Solar DER | 46 | 62 | 83 | 105 | 126 | 141 | 155 | 169 | 180 | 190 | 200 | 210 | 223 | 236 | 251 | 266 | 282 | 299 | 318 | 337 |
| Storage DER | 3 | 6 | 10 | 17 | 24 | 32 | 39 | 47 | 54 | 63 | 70 | 76 | 82 | 86 | 90 | 94 | 101 | 108 | 115 | 123 |
| **Total** | **1234** | **1399** | **1520** | **1772** | **2147** | **2146** | **1947** | **1968** | **2013** | **2056** | **2267** | **2383** | **2401** | **2519** | **2537** | **2607** | **2678** | **2770** | **2816** | **2918** |

**Table 31.** *Additional new carbon portfolio annual resource additions (in MW)*

# 8.3 Comparative analysis of portfolios

## 8.3.1 Portfolio costs

As part of "least-cost" resource planning and optimization, the Plexos model captured relevant incremental costs associated with building, acquiring and operating the power supply portfolios over the 20-year planning horizon. Platte River excluded other costs from the model, like depreciation of existing transmission and generation infrastructure, cost of DERs and administrative and general costs. While these additional costs are important, they are not relevant to the capacity expansion planning process. The cost comparison presented here is not a rate forecast because it does not capture the full revenue requirement needed to set rates. Figure 57 compares the annual cost of all five portfolios.

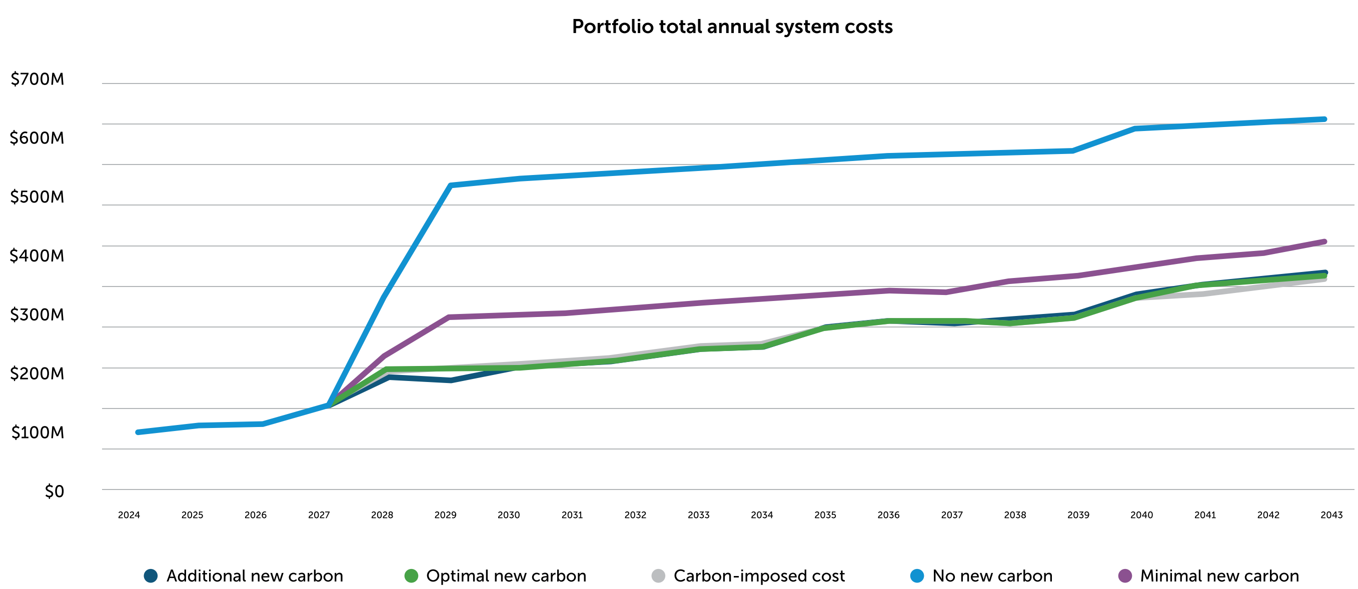



**Figure 57.** *Portfolio total annual system costs*

The no new carbon portfolio stands out as significantly more expensive, with the large buildout of four-hour storage starting in 2027. Annual costs exceed $500 million per year by 2028 and continue an upward trend. The minimal new carbon portfolio is also noticeably more expensive than others, again due to the large battery buildout, with annual costs exceeding $300 million by 2029. The remaining portfolios' costs are similar, with some annual deviations due to small changes in resource size and timing. Looking at the present value of the total portfolio cost in Table 32, costs for the carbon-imposed cost, optimal new carbon and additional new carbon portfolios are within 1%

of each other. But the minimal new carbon portfolio is about 20% more expensive than the three lower-cost portfolios (on a net present value basis), while the no new carbon portfolio is almost twice as expensive, costing an extra $2.6 billion over the planning horizon.

| 20-year net present value ($000) | |
|---|---|
| No new carbon | $5,344,991 |
| Minimal new carbon | $3,372,202 |
| Carbon-imposed cost | $2,779,024 |
| Optimal new carbon | $2,772,407 |
| Additional new carbon | $2,761,036 |

**Table 32.** *Portfolio net present value cost comparison*

As noted previously in this report, the portfolios rely on different technologies to supply differing services. Cost, energy and capacity breakouts in Table 33 highlight the complementary roles of renewable energy and thermal units in the optimal new carbon portfolio. In this case, when looking at the net present value of costs from 2030 through 2043, thermal units account for about 29% of the total cost while supplying almost 58% of the firm capacity and only about 7% of the energy. In contrast, noncarbon resources account for nearly 49% of the cost while contributing just over 91% of the energy but only about 23% of the firm capacity. The thermal resources are more cost-efficient at contributing capacity while noncarbon resources are more cost-efficient at contributing energy. A reliable and low-cost portfolio needs an optimal combination of both capacity and energy. While battery storage does not generate energy, it shifts the renewable production to omitted renewable production hours, thereby contributing to capacity needs and supporting renewable energy integration.

| | % of cost | % of generation | % of capacity |
|---|---|---|---|
| Thermal | 29.2% | 6.9% | 57.9% |
| Noncarbon | 48.8% | 91.5% | 23.1% |
| Battery storage | 15.1% | 0.0% | 19.0% |
| Purchases | 6.9% | 1.6% | 0.0% |
| **Total** | **100.0%** | **100.0%** | **100.0%** |

**Table 33.** *Optimal new carbon portfolio: cost, energy and capacity contribution breakout*

## 8.3.2 Portfolio CO2 emissions

Lowering CO2 emissions is a primary metric driving portfolio development and selection. While there are many ways to quantify a portfolio's emissions, this IRP uses the methodology developed in conjunction with Colorado's Clean Energy Plan (CEP)[29] rules.

Under this methodology, stack emissions from the portfolio are adjusted to reflect additional emissions associated with energy purchases while energy sales assign the associated CO2 to the counterparty buying energy. This netting prevents companies from avoiding emissions by outsourcing generation to an outside counterparty and helps Colorado measure total CO2 emissions due to electricity production and consumption within the state. This methodology also avoids penalizing companies for supplying energy to other utilities. This methodology is a good match for a future market where energy is entirely sold into and purchased from the market without regard to how individual companies balance load and generation. Figure 58 shows annual percent reduction of CO2 emissions for each portfolio relative to Platte River's 2005 baseline emissions.

[29] In 2022, Platte River filed a voluntary CEP with the state of Colorado, laying out a plan to reduce its greenhouse gas emissions by at least 80% by 2030 (compared to a 2005 base line).

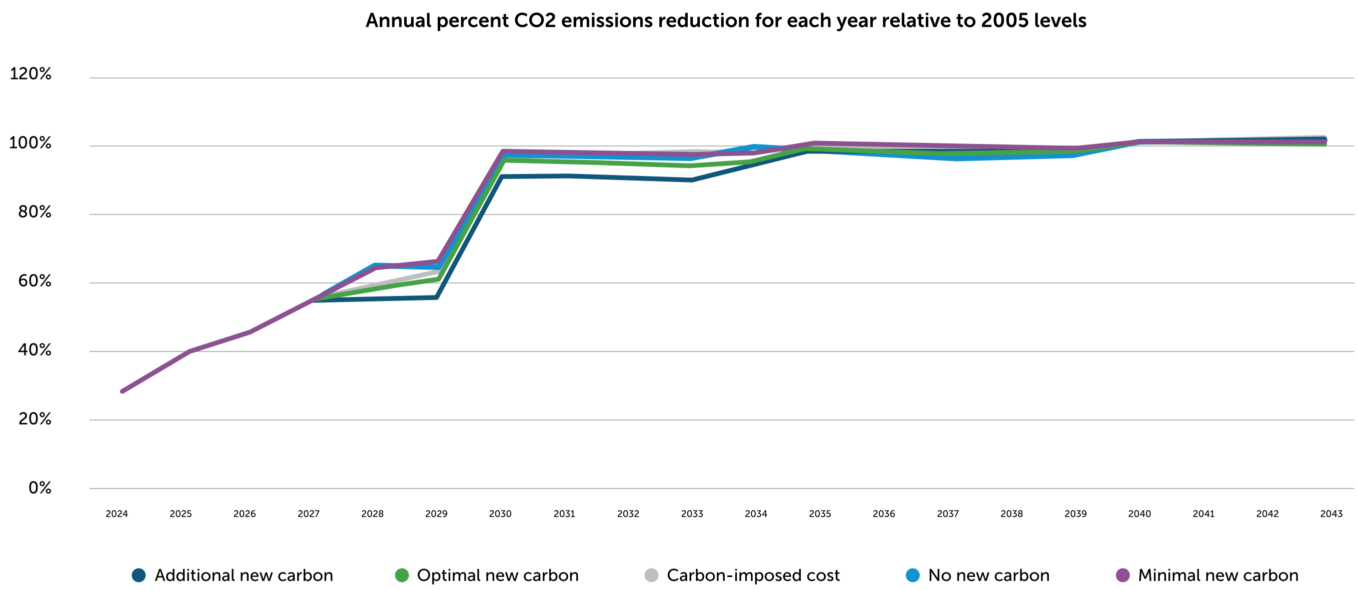



**Figure 58.** *Annual percent CO2 emissions reduction for each year relative to 2005 levels*

Starting in 2025, Platte River makes substantial progress to reduce CO2 emissions due to the renewable energy additions and phased coal retirements. By 2027, we expect all five portfolios to achieve a 55% CO2 reduction. By 2030, the additional new carbon portfolio achieves a 91% reduction, while the remaining portfolios have reductions greater than 95%. After 2035, when the remaining thermal units should begin partially burning green hydrogen, the average carbon reduction for all five portfolios is 99%. This rises to 100% when we assume that all thermal units will transition to 100% hydrogen fuels in 2040, eliminating CO2 emissions.

All portfolios comply with:

- The framework in SB23-198 requiring Platte River to model at least one plan that can demonstrate 46% CO2 reduction (from 2005 levels) by 2027 and one plan that reduces carbon further than its filed CEP; and
- Platte River's voluntary CEP showing its plan to achieve at least 80% CO2 reduction (from 2005 levels) by 2030.

In addition to CO2 emissions reductions, emissions from other pollutants, including volatile organic compounds, carbon monoxide and nitrogen oxides, will also decrease with the coal plant retirements. We assume the new dispatchable generation will use the best available control technologies to maintain compliance with state laws and minimize environmental impact on water resources and air quality.

## 8.4 Recommendation

### 8.4.1 Optimal new carbon portfolio

Planning is a dynamic process, and the IRP is snapshot in time. The 2024 IRP presents a possible future based on the best information available in the summer of 2023. The five portfolios presented in this chapter cover a wide range of future paths. All five portfolios provide reliable electricity supplies during the planning horizon under our assumed set of conditions and variables. But our assumed conditions will probably change. In fact, they will almost certainly change in the long run because we are living amid rapid transition. While all five portfolios provide hypothetical options to meet load requirements and reduce carbon emissions, we must select one that:

- Presents a path towards meeting our RDP and state goals.
- Meets Platte River's three pillars of reliability, financial sustainability and environmental responsibility.
- Presents a path where the actions taken in early years will not unnecessarily limit future options or intensify risks.

The following section highlights the key merits of each portfolio and provides a recommendation.

The **no new carbon portfolio** does not add any new CO2 emitting sources, but it is the most expensive due to heavy reliance on four-hour storage batteries. It builds 2,850 MW of new batteries, almost three times our expected peak demand in 2030. Consequently, it costs about twice as much as some other portfolios. As a not-for-profit entity, Platte River must pass these higher costs to the owner communities, causing significant rate shock.

The no new carbon portfolio does not offer the least CO2-emitting path, as it relies heavily on existing dispatchable generation to complement renewable generation. This portfolio fails the financial sustainability test and is not as effective in reducing CO2 emissions post-2030 as other portfolios. Due to heavy reliance on four-hour battery storage, this portfolio may be unreliable in a dark calm event that spans more days than we have modeled. This portfolio does not present a plausible future path.

The **minimal new carbon portfolio** builds 80 MW of new thermal generation and 1,050 MW of new storage batteries, almost 50% more than

the expected peak demand in 2030. This portfolio emits the least $CO_2$ but is more than 20% more costly than the optimal new carbon portfolio. Just like the no new carbon portfolio, due to heavy reliance on four-hour storage batteries, this portfolio may be unreliable in a dark calm that spans multiple days. Because it does not meet Platte River's requirements for reliability or financial sustainability, this portfolio does not present a workable future path.

The **carbon-imposed cost portfolio** builds 160 MW of new thermal generation and presents a workable path. While this portfolio is reliable for the historically experienced weather uncertainties, it may not be reliable if weather events continue to become more extreme as they have in the recent past.

The **optimal new carbon portfolio** builds 200 MW of new efficient thermal generation and presents a viable path. This portfolio presents a balance between the additional new carbon and carbon-imposed cost portfolios in both cost and the amount of new thermal generation. This portfolio better supports reliability if weather events continue to become more extreme, as they have in the recent past. This is our recommended portfolio.

The **additional new carbon portfolio** builds 240 MW of new efficient and flexible thermal generation. It is the lowest-cost portfolio but emits more $CO_2$ than some other portfolios that also meet reliability and financial sustainability pillars. This portfolio presents a workable future path.

The carbon-imposed cost, optimal new carbon and additional new carbon portfolios are potentially workable options. There are important differences among the three. After careful consideration, Platte River recommends the optimal new carbon portfolio because it optimally balances the organization's three foundational pillars, offers more flexible and lower-risk early decisions, has the robustness to withstand changes in assumptions and helps advance the 100% noncarbon energy goal of the RDP.

The recommended portfolio is a possible path for the future and not a firm plan. Platte River will further refine this path during implementation, incorporating market conditions, technology evolution, availability, and cost and timing of new resources. This plan will evolve as needed to align with our board's direction and our owner communities' wishes. Staff will continue to refine this portfolio with new data, assumptions, and market conditions. With these refinements and improvements, Platte River will continue to advance toward a 100% noncarbon supply mix while maintaining its three pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services.

## 8.5 Risk assessment and sensitivity analysis

Platte River developed all five portfolios using several assumptions, assessments and forecasts about commodity prices, customer load growth, costs of renewables, DER adoption rates, market evolution, technology evolution, and other inputs. But these inputs are unlikely to occur exactly as assumed, requiring us to adapt. In this section, we outline the risks our plan faces, summarize our sensitivity analyses and provide options to adjust the plans for key risks. As time passes and newer information is available, we will modify our plans.

### 8.5.1 IRP risks and barriers

As Platte River moves forward with this IRP implementation, we must consider two types of risks. First, there are execution risks that complicate portfolio implementation. These risks tend to be very specific to the composition of the portfolio, driven by large, complex external factors (such as global supply chains) and are difficult to hedge because they are unique and difficult to forecast. We discuss these risks in detail below.

#### 8.5.1.1 Execution risks

- **Cost escalation** – As discussed in section 3.4.3, renewable costs continue to escalate dramatically. Platte River uses the latest market data to develop plans, but costs continue to rise, and new generation may be more expensive than anticipated. Renewable energy seems to carry the highest exposure due to both high market demand and complex, immature supply chains. Thermal generation has seen moderate escalation and other resource additions could be impacted by trade policies. Platte River must be prepared to adjust to the best portfolio mix to reflect evolving cost considerations.

- **Siting complications** – Individual projects have unique siting challenges. Platte River must address community concerns about the impact of a project itself or its transmission connections. Local regulation can also shift rapidly and require project modifications that often add costs. Projects may also encounter unexpected geological, hydrological or environmental conditions.

- **Technology evolution** – Our proposed portfolios assume a specific timeline of technology readiness. This forecast is based on our best estimates, but technology development is beyond Platte River's control. If specific storage technologies fail to mature or hydrogen is not available at the required volumes, the portfolio would need to be reoptimized to accommodate this new reality. More specifically, we assumed long-duration energy storage and green hydrogen will be available and economically viable for commercial deployment in 2035 to help continue to decarbonize Platte River's resource mix . If these technologies are not available at the projected dates or are available sooner, our decarbonization schedule will change accordingly.

- **DER adoption rates** – Platte River is proactively working with its owner communities to forecast and incentivize customer-sited resources. Like other technology forecasts, the exact trajectory of deployment of many new and emerging technologies is uncertain. Rooftop solar, electric vehicles, beneficial building electrification and battery storage systems

all impact both the energy mix and flexibility of the system. If there are unforeseen breakthroughs or complications, Platte River will need to adjust its resource mix in response.

### 8.5.1.2 Operational risks

There are operational risks that can occur in each plan once they are executed. It is easier to understand and quantify these operational risks with specific model runs. Their impact on portfolio viability is still significant and uncertain, but it is easier to evaluate the quantifiable tradeoffs.

- **Fuel and market price risk** – Portfolios are developed using the best estimates of future fuel and energy market prices. Past volatility suggests the potential for future volatility. Sensitivity runs modeling gas and power prices help establish each portfolio's susceptibility to this input and the consequences of future deviations from the expected value.

- **Regulatory risk on carbon accounting and emissions** – There continues to be a range of opinions on how carbon emissions will be regulated. The presence or absence of a carbon tax can impact the economics of a portfolio. Again, a sensitivity analysis can help quantify the financial impacts of a carbon tax.

- **Market evolution** – The implementation of a western energy market will impact different resources in different ways. Transmission congestion may erode the economics of remotely sited resources, while a robust energy market may impact price levels and volatility. If multiple utilities add renewable resources and transmission constraints emerge in moving power out of our region, there is a risk that excess renewable generation will depress market prices. This risk is more difficult to quantify than other operational risks, but Platte River continues to explore the potential range of impacts as the market develops.

The risks described above can impact a portfolio in different ways. One way to analyze their impacts is to conduct sensitivity analyses, where we change a driver or variable and measure the resulting impact on the portfolio. Section 8.5.2 discusses these analyses.

Because these risks and assumptions can change simultaneously, the combined effect can be large and drive us to change the portfolio mix. In section 8.5.3, we assess the combined risk of renewable cost increases and market price changes and review potential portfolio modifications to reduce this risk.

## 8.5.2 Sensitivity analyses

To understand the robustness of the modeled portfolios, the IRP process tests the portfolios under assumptions different from the base assumptions. In a sensitivity analysis, a single assumption or input is changed (gas prices, for example) and the portfolio is re-evaluated. Portfolios with stronger responses to the new assumption or input show greater risk. This analysis provides a deeper understanding of the tradeoff between cost and risk. For this IRP, Platte River performed sensitivity analyses on two main inputs: natural gas prices and renewable energy prices.

### 8.5.2.1 Natural gas prices

Natural gas prices can impact a portfolio in two ways. First, the price of this fuel directly influences regional market prices, which impacts the volume and cost or revenue of imports and exports to and from the Platte River system. Second, the portfolios continue to consume modest amounts of natural gas in the future, so changes in price directly impact the economics of the thermal generation. In this analysis, gas prices were tested at both higher and lower levels than the base assumption used in the portfolio development. Siemens, the supplier of the base gas price forecast, also supplied the high and low gas price trajectories, seen in Figure 39 earlier in this document, as well as associated market prices for each sensitivity.

### 8.5.2.2 High gas prices

Under this sensitivity, gas prices are 20% higher on average from 2030 to 2040. On a net present value basis, the portfolios' costs change very little, indicating the relatively small role of gas in future portfolios. On the low side, there is a 0.3% savings for the minimal new carbon portfolio while the additional new carbon portfolio has a cost increase of 1.4%. In general, higher gas prices increase the system operating cost due to higher fuel expenditures, but these increases are partially offset by higher sale revenues from higher market prices. Portfolios with more gas generation will see a net increase in cost, while portfolios with more must-sell renewable energy will benefit from the attractive market prices and see a slight savings.

### 8.5.2.3 Low gas prices

For this sensitivity, gas prices remain relatively flat starting in 2026. While the base case and high-price sensitivity show average escalation rates of 4.45% and 5.71% respectively through 2043, the low-price curve has a net gain of 0.2% by 2043, with a small decline during the 2030s. As expected, the results are the opposite of the high gas price sensitivity. Since this sensitivity sees a larger change to gas prices, with an average decrease of 54% relative to the base assumption, the change in net present value is more noticeable than in the high gas price sensitivity. The additional new carbon portfolio sees a cost savings of 5.1% and the optimal new carbon portfolio sees a savings of 3.6%. The minimal new carbon and no new carbon portfolios see modest savings of 0.6% and 0.8%, respectively.

### 8.5.2.4 Renewable energy prices

As discussed in section 3.4.3, renewable energy projects have seen significant cost increases in recent years.

In addition to the cost drivers of the projects themselves (including supply chain issues and competition for renewable resources), a second source of uncertainty around the cost of new renewable energy comes from Platte River's expected market participation. There is some possibility that the market will fail to launch as planned, or will launch with a different mix of participants, which would leave some projects exposed to higher transmission costs than might otherwise be expected in a market. Assuming the market does move forward as planned, there is still substantial uncertainty around the additional costs of transmission congestion, both under the existing portfolio and as regional portfolios evolve with more renewable energy concentrated at the optimal sites. Without a market, or with a market that is more congested than expected, the delivered cost of our renewable energy would rise.

For these reasons, Platte River ran a sensitivity analysis on renewable energy prices. We evaluated price increases for new wind and solar projects under each portfolio. Table 34 compares the base assumption to the higher price sensitivity for selected years. We did not test prices for energy storage and thermal generation because Platte River has not seen similar price volatility in those markets and their transmission congestion risk is much lower.

| Wind cost (including transmission costs) | | | Solar cost | |
|---|---|---|---|---|
| | Base | High sensitivity | Base | High sensitivity |
| 2030 | 32.85 $/MWh | 40.99 $/MWh | 30.01 $/MWh | 40.37 $/MWh |
| 2035 | 34.82 $/MWh | 43.75 $/MWh | 31.22 $/MWh | 41.99 $/MWh |
| 2040 | 36.87 $/MWh | 46.67 $/MWh | 32.43 $/MWh | 43.62 $/MWh |

**Table 34.** *Renewable PPA prices*

Because each portfolio adds a similar amount of renewable energy, the results across the portfolios are reasonably close. On a net present value basis, the smallest change is a $181 million increase for the additional new carbon portfolio, while the largest increase is $198 million for the carbon-imposed cost portfolio. The optimal new carbon portfolio has a cost increase of $190 million, which is about a 7% increase if renewable energy prices reach the level projected in the sensitivity.

The last two columns of Table 35 illustrate how the relative difference among portfolio costs changes from the base case to the sensitivity case. These intra portfolio cost comparisons are shown relative to the lowest cost portfolio referred to as the additional new carbon portfolio (labeled as "ANC" in the table below). For the base case runs, the cost of the no new carbon portfolio is 93.6% higher relative to the additional new carbon portfolio, while the sensitivity case is 88.0% higher. There is very little change in the relative cost differences for the remaining portfolios.

| | Base and sensitivity comparison | | | Intra portfolio cost comparison | |
|---|---|---|---|---|---|
| Portfolio | Base case | Sensitivity: high RE | % change | Base case: % diff vs. ANC | Sensitivity: % diff vs. ANC |
| No new carbon | $5,344,991 | 5,531,559 | 3.5% | 93.6% | 88.0% |
| Minimal new carbon | $3,372,202 | 3,559,856 | 5.6% | 22.1% | 21.0% |
| Carbon-imposed cost | $2,779,024 | 2,976,911 | 7.1% | 0.7% | 1.2% |
| Optimal new carbon | $2,772,407 | 2,962,228 | 6.8% | 0.4% | 0.7% |
| Additional new carbon | $2,761,036 | 2,941,920 | 6.6% | 0.0% | 0.0% |

**Table 35.** *Renewable PPA prices*

## 8.5.2.5 Sensitivity analysis summary

While uncertainty about some model inputs is unavoidable, quantifying the impacts of those uncertainties can help manage the risks associated with them. Table 36 compares the net present value costs across the base case assumptions and the sensitivities described above.

| Net present values | Base | High gas and power | Low gas and power | High renewable energy prices |
|---|---|---|---|---|
| No new carbon | $5,344,991 | $5,343,332 | $5,304,721 | $5,531,559 |
| Minimal new carbon | $3,372,202 | $3,363,500 | $3,352,897 | $3,559,856 |
| Carbon-imposed cost | $2,779,024 | $2,783,634 | $2,724,507 | $2,976,911 |
| Optimal new carbon | $2,772,407 | $2,794,671 | $2,672,710 | $2,962,228 |
| Additional new carbon | $2,761,036 | $2,800,210 | $2,620,375 | $2,941,920 |

**Table 36.** *Net present value cost comparison with gas prices and renewable prices*

At a high level, the no new carbon portfolio and the minimal new carbon portfolio are uncompetitive in every case. Table 37 converts the net present value costs into rankings for the base case and each sensitivity, with the result that the no new carbon portfolio is last under every assumption tested and the minimal new carbon portfolio is fourth under every assumption tested.

| Net present value rankings | Base | High gas and power | Low gas and power | High renewable energy prices | Average |
|---|---|---|---|---|---|
| No new carbon | 5 | 5 | 5 | 5 | 5.0 |
| Minimal new carbon | 4 | 4 | 4 | 4 | 4.0 |
| Carbon-imposed cost | 3 | 1 | 3 | 3 | 2.5 |
| Optimal new carbon | 2 | 2 | 2 | 2 | 2.0 |
| Additional new carbon | 1 | 3 | 1 | 1 | 1.5 |

**Table 37.** *Portfolio ranking with sensitivity analysis*

The top three portfolios are more competitive, and their relative value depends on the future trajectory of prices and the impacts of CO2 emissions. The optimal new carbon portfolio proves to be robust, with a second-place ranking in every run. This portfolio is, on average, only 0.9% more expensive than the best portfolio in any given sensitivity (including the base case). While some portfolios may perform better in a specific set of circumstances, the optimal new carbon portfolio performs well across the range of outcomes and proves to be a cost-effective and robust solution.

## 8.5.3 Excess renewable and market participation risk

With a substantial increase in intermittent renewable resources, Platte River faces an increasing risk from the mismatch in timing between customer demand and when renewable generation is available. Some of the mismatch can be managed with energy storage, but it would be impractical to balance the entire renewable energy portfolio using current battery storage technology. When there is insufficient renewable energy, Platte River can purchase energy from the market, withdraw stored energy, or rely on thermal generation to fill the gap. When there is too much energy, Platte River will store the excess (after meeting its load) and must sell any additional renewable energy into the market or curtail the resource.

Starting in 2030, Platte River anticipates having about 10% to 35% surplus energy on an annual basis. Of that excess, about 75% is expected to be sold, while the remainder will be curtailed due to limited energy demand and constrained transmission systems.

Because renewable energy contracts are structured as take-or-pay, Platte River must pay the full price of the PPA whether we take delivery of the energy or not. In this context, Platte River will sell excess renewable energy into the market if the market price is greater than $0 but will incur a loss if the market price is below the PPA price. Therefore, the economic value of the surplus renewable energy depends on the cost of the PPA relative to the market price of the energy at the time of the excess energy.

Given that the entire region is adding wind and solar resources, we anticipate market prices to be lowest when we have surplus renewable energy. Figure 59 illustrates the average expected monthly power prices in 2031 and monthly excess renewable energy as a percentage of the total monthly energy required by Platte River customers.

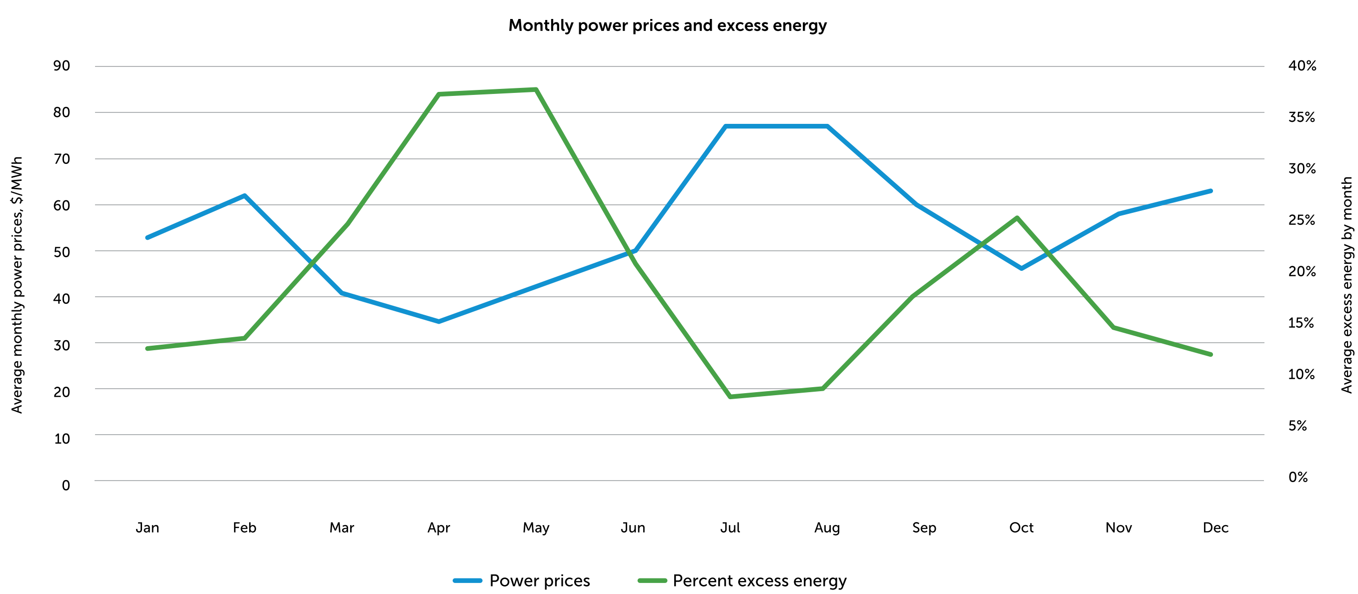



**Figure 59.** *Monthly power prices and excess energy*

The blue line shows average monthly prices, while the green line shows excess energy as a percent. The average prices are lowest in April and May, when the excess energy is above 35% of Platte River's needs. Excess energy is relatively low in higher-priced months of summer and winter.

To better understand the supply-demand balance and assess energy risk, Platte River staff analyzed expected hourly operations during the year 2031 using 24 historical hourly weather patterns for the recommended portfolio, which called for adding 400 MW of new wind by 2030. The diversity of weather data allows a broader quantification of the risk across multiple weather years, rather than relying on a single representative year.

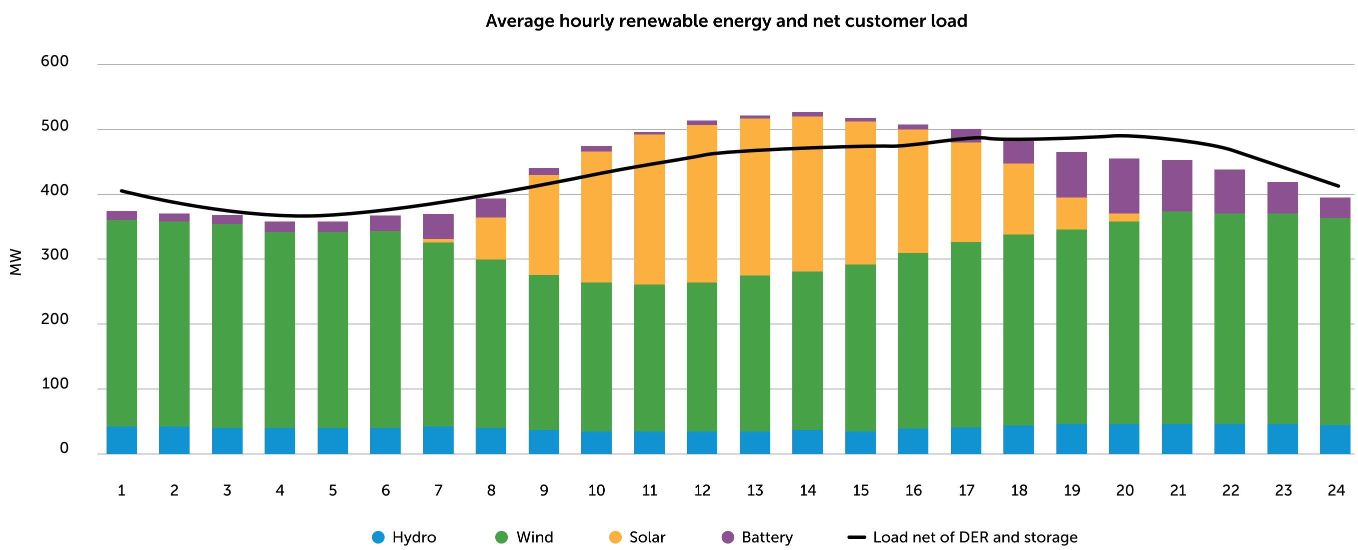



**Figure 60.** *Average hourly renewable energy and net customer load*

Figure 60 summarizes the average excess megawatts by hour of day and month of the year. During the day, we have excess energy in midday when solar output is high. However, during the morning and evening hours, when the load is ramping up, the Platte River system needs dispatchable capacity and market access.

Balancing this excess renewable energy with the need for sufficient energy during high demand is one of the primary tasks of this IRP. Platte River developed the recommended portfolio with 400 MW of new wind, with the wind power purchase price around $32/MWh, and market prices in the 2030s around $50/MWh, making excess energy revenue positive. However, if market prices continue to drop with the addition of renewable resources in the region and demand for renewable energy continuing to rise, the cost of renewable energy will increase. In this scenario, the risk is not only the limited value from excess renewable energy but also market price volatility.

Platte River will need to consider these risks before fully implementing the recommended plan. This exposure to factors outside Platte River's control makes managing the portfolio's risk a critical part of the execution phase. Platte River will continue to monitor commodity prices (like gas), market power price forecasts, and the cost of renewable energy to refine and rebalance the plan as necessary to meet our financial sustainability pillar. If necessary, we can adjust the renewable mix or storage capacity to mitigate risk if it is cost-effective.

# 09

# Action plan

Platte River will continue to work toward the RDP goal over the next five years. Platte River plans to retire coal generation, add more renewable generation, add energy storage, add a VPP, join a full organized energy market and add efficient dispatchable thermal generation to complement renewable intermittency.
We expect to carry out the following specific activities.

## 9.1 2024-2028: Execution phase

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| **Renewable energy acquisition** | Contract for new 107 MW solar from the 2022 solar RFP | 2024 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>• Technology evolution<br>Operational risks (section 7.5.1.2)<br>• Market evolution |
| | Contract for new 250 MW wind from the 2023 wind RFP | 2024 | |
| | Begin commercial operation of 150 MW Black Hollow Solar project | 2025 | |
| | Begin commercial operation of a 130 MW solar project | 2027 | |
| **Dispatchable capacity (reliability)** | Contract to add up to 20 MW of distributed energy storage from 2021 solar and storage RFP | 2024 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>• Technology evolution<br>• DER adoption rates<br>Operational risks (section 7.5.1.2)<br>• Fuel and market price risk<br>• Regulatory risk on carbon accounting and emissions<br>• Market evolution |
| | Issue RFP for four-hour battery energy storage system | 2024 | |
| | Review results from all-dispatchable-resource RFP | 2024 | |
| | Begin adding up to 200 MW of dispatchable thermal generation resources. Major activities include:<br>• Apply for air and land use permits<br>• Identify actions related to ordering some long lead time equipment, especially related to power transmission<br>• Develop initial project design and enlist engineering, procurement and construction contractor | 2024 | |

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| **Dispatchable capacity (reliability)** | Issue RFP for systems and services to support development of a VPP that can provide dispatchable capacity for Platte River and the owner communities | 2024 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>• Technology evolution<br>• DER adoption rates<br>Operational risks (section 7.5.1.2)<br>• Fuel and market price risk<br>• Regulatory risk on carbon accounting and emissions<br>• Market evolution |
| | Issue RFP for dispatchable thermal resource development if the 2024 all dispatchable resource RFP does not result in an acceptable project | 2025 | |
| | With our owner's engineer and contractor, complete plant design for new resource and balance of plant services | 2025 | |
| | Complete battery energy storage system agreements | 2025 | |
| | Issue RFP for additional energy storage system | 2025 | |
| | Plan VPP systems design and architecture | 2025 | |
| | Start work on a demonstration project for long-duration energy storage system | 2025 | |
| | Build VPP systems, system integrations and develop key functionality | 2026 | |
| | Begin commercial operation of up to 25 MW of distributed energy storage from 2021 solar RFP | 2026 | |
| | Launch VPP with 7 MW dispatchable capacity | 2027 | |

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| **Customer programs** | Plan and develop VPP customer programs | 2025 | Execution risks (section 7.5.1.1)<br>• Technology evolution<br>• DER adoption rates<br>Operational risks (section 7.5.1.2)<br>• Market evolution<br>VPP system integration<br>Third-party DER device aggregators |
| | Launch VPP customer programs | 2026 | |
| **Community engagement** | Continue public education campaign to engage communities, customers in the energy transition | 2024-2028 | |
| | Support renewable energy project acquisitions and engage communities through groundbreaking events, ribbon-cutting ceremonies | 2025-2028 | |
| **Transmission** | Complete construction and energize the 230-kV interconnection switching station (Severance substation) to interconnect new renewable resources | 2025 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>Operational risks (section 7.5.1.2)<br>• Market evolution |
| **Markets** | Begin training staff to prepare for SPP RTO West market entry | 2024 | Operational risks (section 7.5.1.2)<br>• Market evolution<br>System integration<br>Market tariff and resource adequacy |
| | Screen and select market interface software | 2024 | |
| | Begin testing operations in SPP RTO West | 2025 | |
| | Join SPP RTO West market operations on April 1 | 2026 | |

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| Other enabling activities | Finalize and file a just transition plan with the state of Colorado for workers affected by Rawhide Unit 1's closure | 2024 | Interest rates |
| | Working alongside other owners, retire Craig Unit 1 (of which Platte River owns a 77 MW share) | 2025 | |
| | Initiate 2028 IRP process | 2026 | |
| | Issue bonds to fund capital investments | 2025-2026 | |
| | Continue 2028 IRP process including:<br>• Receive studies from external consultants<br>• Execute community engagement activities to educate public, collect stakeholder feedback<br>• Conduct modeling and analyze portfolios<br>• Compile draft report | 2027 | |

## 9.1 2024-2028: Execution phase

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| **Renewable energy acquisition** | Begin commercial operation of new wind generation | 2028 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>• Technology evolution<br>Operational risks (section 7.5.1.2)<br>• Market evolution |
| **Dispatchable capacity (reliability)** | Testing, commissioning, and operation of new dispatchable thermal resource | 2028 | Execution risks (section 7.5.1.1)<br>• Cost escalation<br>• Siting complications<br>• Technology evolution<br>• DER adoption rates<br>Operational risks (section 7.5.1.2)<br>• Fuel and market price risk<br>• Regulatory risk on carbon accounting and emissions<br>• Market evolution |
| | Begin commercial operation of energy storage systems (for which RFP was issued in 2025) | 2028 | |
| | Grow VPP dispatchable capacity to 15 MW and develop market dispatch capabilities | 2029 | |
| | Grow VPP dispatchable capacity to 24 MW and develop distribution dispatch capabilities | 2029 | |
| | Develop a mobile app to help customers and distribution utilities connect with Platte River's system | 2028-2030 | |
| **Community engagement** | Support mobile app deployment with communications and community activations | 2028-2030 | |
| | Continue public education campaign to engage communities, customers in the energy transition | 2028-2030 | |

| Resource plan component | Anticipated actions | Approximate timing | Key risks that may impact actions |
|---|---|---|---|
| Other enabling activities | Implement the Just Transition Plan | 2024-2030 | |
| | Working alongside other owners, retire Craig Unit 2 (of which Platte River owns a 74 MW share) | 2028 | |
| | Seek approval from Platte River Board for 2028 IRP; file with WAPA | 2028 | |
| | Retire Rawhide Unit 1 by December 31 | 2029 | |

# 10 Appendices

# **Appendix A:** IRP checklist for WAPA

| Document section | Requirement | Included in this IRP | Section number |
|---|---|---|---|
| **IRP design, IRP study results**<br><br>**Power markets**<br><br>**Energy efficiency**<br><br>**DER integration, flexible DERs and the virtual power plant**<br><br>**IRP portfolios** | Does the IRP evaluate the full range of alternatives for new energy resources, including:<br><br>• new generating capacity?<br>• power purchases?<br>• energy conservation and efficiency?<br>• cogeneration and district heating/cooling applications?<br>• renewable energy resources? | ✓ | 6.3.3, 6.3.4, 6.3.5, 6.3.6, 6.3.7<br>7.1, 7.4, 8.2, 8.3<br>4.1.5, 6.3.4, 6.3.5,<br>5.3.2<br><br>5.3.1<br>7.4, 8.2, 8.3 |
| **Planning for a reliable future power supply** | Does the IRP provide adequate and reliable service to the customer's electric consumers? | ✓ | 7.3 |
| **IRP design, IRP study results** | Does the IRP take into account the necessary features for system operation? | ✓ | 4.2.1, 7.3, 8.5 |
| **DER integration, flexible DERs and the virtual power plant** | Does the IRP take into account the ability to verify energy savings achieved through energy efficiency? | ✓ | 5.3 |
| **DER integration, flexible DERs and the virtual power plant** | Does the IRP take into account the projected durability of such savings measured over time? | ✓ | 5.3 |
| **Load forecast methodology and data** | Does the IRP treat demand and supply resources on a consistent and integrated basis? | ✓ | 5.3, 5.4.1, 5.4.2 |
| **Planning for a reliable future power supply** | Does the IRP consider electrical energy resource needs? | ✓ | 7.3 |
| **Energy and capacity planning, DER integration, flexible DERs and the virtual power plant, supply side generation resources, IRP portfolios** | Does the IRP identify and compare resource options? | ✓ | 4.1.2, 5.3, 6.3, 7.4, 7.5 |

| Document section | Requirement | Included in this IRP | Section number |
|---|---|---|---|
| **Comparative analysis of portfolios, portfolio recommendation, risk assessment and sensitivity analysis** | Does the IRP clearly demonstrate that decisions were based on a reasonable analysis of the options? | ✓ | 8.3, 8.4, 8.5 |
| **Action plan** | Does the IRP include an action plan describing specific actions the customer will take to implement the IRP? | ✓ | 9 |
| **Action plan** | Does the IRP list the time period that the action plan covers? | ✓ | 9 |
| **Action plan** | Does the IRP include an action plan summary consisting of:<br>• Actions the customer expects to take in accomplishing the goals identified in the IRP?<br>• Milestones to evaluate accomplishment of those actions during implementation?<br>• Estimated energy and capacity benefits for each action planned? | ✓ | 9 |
| **Portfolio CO2 emissions** | Does the IRP, to the extent practicable, minimize adverse environmental effects of new resource acquisitions and document these efforts? | ✓ | 8.3.2 with additional text from environmental |
| **Portfolio CO2 emissions** | Does the IRP include a qualitative analysis of environmental effects in a summary format? | ✓ | 8.3.2 |
| **Stakeholder engagement process** | Does the IRP provide ample opportunity for full public participation in preparing and developing the IRP? | ✓ | 3.7 |

| Document section | Requirement | Included in this IRP | Section number |
|---|---|---|---|
| **Stakeholder engagement process** | Does the IRP include a brief description of public involvement activities? | ✓ | 3.7 |
| **Board resolution to approve the 2024 IRP** | Does the IRP document that each MBA member approved the IRP, confirming that all requirements have been met? | ✓ | Appendix C |
| **Board resolution to approve the 2024 IRP** | Does the IRP contain the signature of each MBA member's responsible official, or document passage of an approval resolution by the appropriate governing body? | ✓ | Appendix C |
| **Electricity demand** | Does the IRP contain a statement that the customer conducted load forecasting, including specific data? | ✓ | 5.1-5.4 |
| **Planning for a reliable future power supply, portfolio CO2 emissions, DER integration, flexible DERs and the virtual power plant, IRP portfolios** | Does the IRP contain a brief description of measurement strategies for identified options to determine whether the IRP's objectives are being met? | ✓ | 7.3.2.2, 8.3.2, 5.3 |
| **Planning for a reliable future power supply, portfolio CO2 emissions, DER integration, flexible DERs and the virtual power plant, IRP portfolios** | Does the IRP identify a baseline from which the customer will measure the benefits of IRP implementation? | ✓ | 7.3.2.2, 8.3, 5.3 |
| | Does the IRP specify the responsibilities and participation levels of individual members of the MBA and the MBA? | N/A | |

# **Appendix B:** 2024 Just Transition Plan

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

# 2024 JUST TRANSITION PLAN

# BACKGROUND

Platte River Power Authority (Platte River) is a not-for-profit, community-owned public power generation and transmission utility that provides safe, reliable, environmentally responsible and financially sustainable energy and services to the communities of Estes Park, Fort Collins, Longmont and Loveland, Colorado, for delivery to their distribution utility customers. Platte River owns and operates Rawhide Energy Station (Rawhide), located roughly ten miles north of Wellington, Colorado. Rawhide consists of one 280 megawatt (MW) capacity coal fired boiler (Unit 1) and five natural gas-fired combustion turbines with a combined 388 MW capacity (Units A, B, C, D and F) that support peak power demand. Additionally, Rawhide also has 52 MW of solar and a 2 MW-hour battery storage system.

Platte River, like other Colorado utilities, is transforming how it generates and delivers energy. In 2018, Platte River's board of directors (the board) approved the Resource Diversification Policy (RDP), which directed Platte River to proactively work toward achieving a 100% noncarbon energy mix by 2030 while maintaining Platte River's three foundational pillars of providing reliable, environmentally responsible and financially sustainable electricity and services. A significant milestone on the journey to 100% noncarbon energy is its commitment to retire Unit 1 by the end of 2029. This commitment is reflected in its current Integrated Resource Plan (2024 IRP) and in its Clean Energy Plan, which was submitted to the state of Colorado in 2022. This commitment is also included in Resolution 08-24 which formally announces Unit 1's accelerated retirement as part of the 2024 IRP. With Platte River's commitment to retiring Unit 1, the utility will submit this document – Platte River's Just Transition Plan – to the Colorado Office of Just Transition within 30 days of Platte River's board of directors approving Resolution 08-24 and the 2024 IRP.

Platte River is not just transforming its energy mix. Embracing the future will require Platte River to change and adapt as an organization. Platte River entered the Southwest Power Pool (SPP) Western Energy Imbalance Service market in 2023 and will enter SPP's Regional Transmission Organization –West (RTO–West) in April 2026, which is one of the key advancements identified to further the RDP. To support entering RTO–West, Platte River is initiating a strategic workforce analysis to identify the necessary changes to its people, processes, and technologies.

Platte River's board passed Resolution 08-2020 (Workforce Resolution) in 2020, when Platte River announced Unit 1's retirement. The Workforce Resolution planned six principles that Platte River is committed to follow when implementing its transition plan. These principles are:

- Transparency
- Workforce Planning
- Workforce Opportunities
- Workforce Training
- Retention Strategies
- Transition Support

Platte River, through its Workforce Resolution and Just Transition Plan, will continue to demonstrate its unwavering commitment to support and retain employees who wish to remain with the organization through Unit 1's retirement and its transition to a clean energy future.

# PLATTE RIVER AT A GLANCE

Platte River Power Authority is a not-for-profit, community-owned public power utility that generates and delivers safe, reliable, environmentally responsible and financially sustainable energy and services to Estes Park, Fort Collins, Longmont and Loveland, Colorado, for delivery to their utility customers.

| Headquarters | 2023 peak demand of owner communities |
|---|---|
| Fort Collins, Colorado | 680 MW |
| **General manager/CEO** | **2023 deliveries of energy** |
| Jason Frisbie | 4,506,208 MWh |
| **Began operations** | **2023 deliveries of energy to owner communities** |
| 1973 | 3,161,533 MWh |
| **Staff** | **Transmission system** |
| 268 | Platte River has equipment in 27 substations, 263 miles of wholly owned and operated high-voltage lines, and 522 miles of high-voltage lines jointly owned with other utilities. |

# PLATTE RIVER POWER AUTHORITY'S 2024 JUST TRANSITION PLAN

As required by House Bill 19-1314 and to further its commitment to Unit 1's retirement and the 100% noncarbon goal of its RDP, Platte River submits this Just Transition Plan to the Colorado Office of Just Transition. Platte River views this Just Transition Plan as a living document and anticipates that it will revise both the Just Transition Plan and its IRP as Unit 1's Dec. 31, 2029 retirement date nears. Platte River's Just Transition Plan follows the six principles of its Workforce Resolution and supports its ongoing commitment to retain employees through the energy transition and to avoid involuntary separations (layoffs) due to Unit 1's retirement.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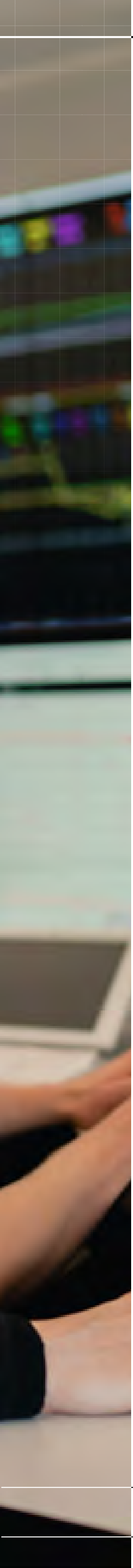
09
22



# PRINCIPLE 1: TRANSPARENCY

Platte River management will make every effort to communicate impacts proactively and transparently to employees as decisions are made, including the timelines of planned events.

To implement this principle, Platte River consistently updates both Rawhide and Headquarters staff on the transition plan, including at plant and business meetings and through updates to Platte River's board. Platte River also discusses the upcoming transition, including its commitment to retain employees after Unit 1's retirement, with external candidates as part of the interview and hiring process. Platte River offers RTO–West training to the whole organization and will provide the results of its upcoming gap analysis to internal stakeholders so that each department can evaluate the changes to people, processes, and technology that will be needed in 2026 and beyond. Platte River also plans to provide this Just Transition Plan and the 2024 IRP to all employees through multiple channels and opportunities for employee to submit questions, concerns, and feedback on Platte River's transition.

Platte River's Just Transition Plan is led by a cross-functional team including representatives from power generation, operations, human resources, communications, and legal affairs and is sponsored by Platte River's Chief Operating Officer – Generation, Transmission and Markets. This cross-functional team currently plans additional outreach and communication to staff on workforce planning and workforce transition to accompany the Just Transition Plan and 2024 IRP. The cross-functional team is guided by the RDP, the Workforce Resolution and Platte River's Strategic Plan as it deploys Platte River's strategic workforce planning tools to further those goals and establish ongoing dialogue on how to best meet them in a just and transparent way.

# PRINCIPLE 2: WORKFORCE PLANNING

Platte River management will continue to evaluate and identify workforce needs and to communicate its needs to staff.

To implement this principle, Platte River's leadership, partnering with its human resources department, is currently using strategic planning, data modeling, and other workforce planning tools to anticipate Platte River's future workforce needs. While this modeling is an imperfect science, Platte River is committed to using the best tools and data available, and to continually updating its models as Unit 1's retirement nears and Platte River's future needs become clearer.

It is important to note that Platte River is growing as an organization, even as Unit 1 retires. It will need additional staff in many functional areas to meet the RDP and the Strategic Plan, including in power marketing, power delivery, compliance, information technology, and substation maintenance. Platte River has determined how future vacancies will provide opportunities to transition Rawhide employees to other positions in the organization.

Platte River's internal modeling also shows that its workforce transition will largely be driven by natural attrition and retirement, not through layoffs. Many current Platte River employees have more than 25 years of service. Historically, Platte River attrition has been low amongst its longest-tenured employees, a trend that it anticipates may change as more staff members reach retirement age. Platte River, like other employers, has experienced increased attrition and volatility amongst its newer employees, a trend that it anticipates will not change between now and 2029.

Figure 1 and Figure 2 show the general trends that Platte River has modeled and observed in attrition by years of service, both for the organization as a whole and for Rawhide.

**Figure 1: Platte River Attrition by Years of Service**

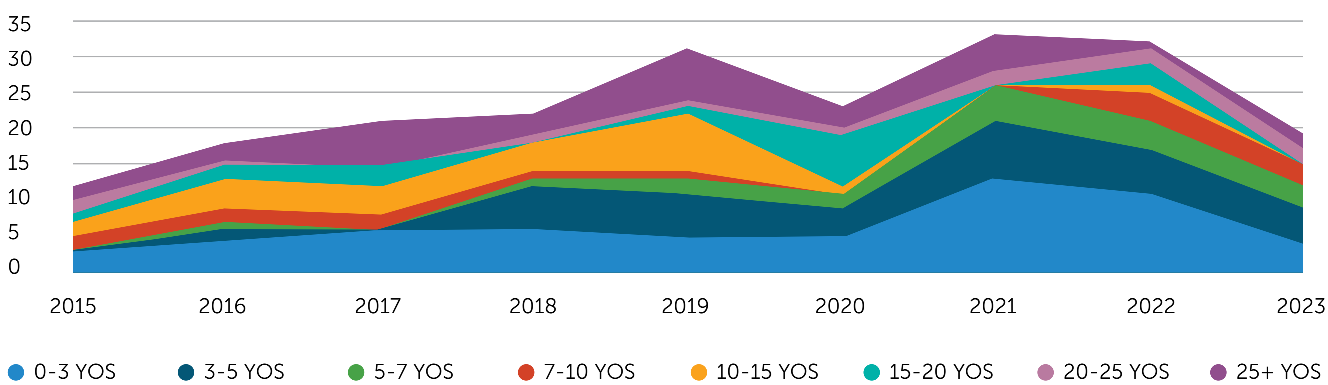


**Figure 2: Rawhide Attrition by Years of Service**

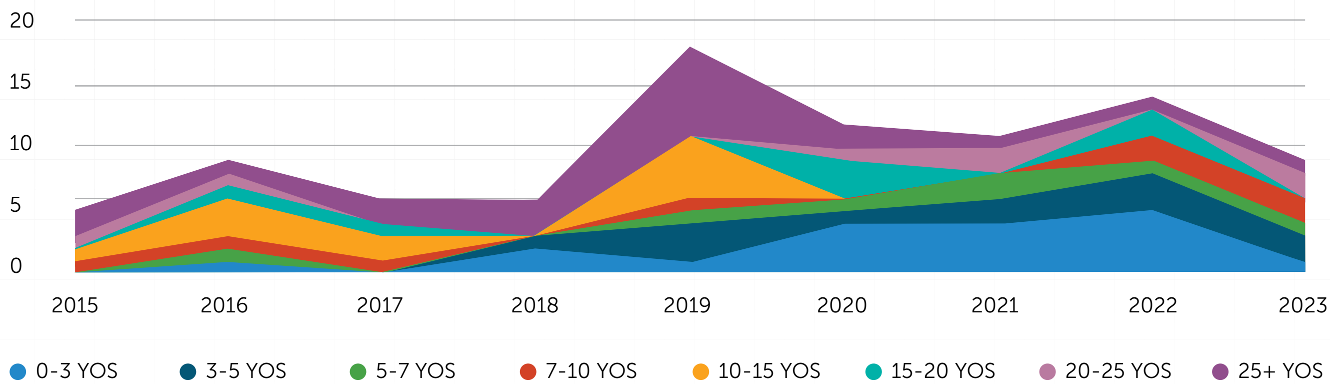
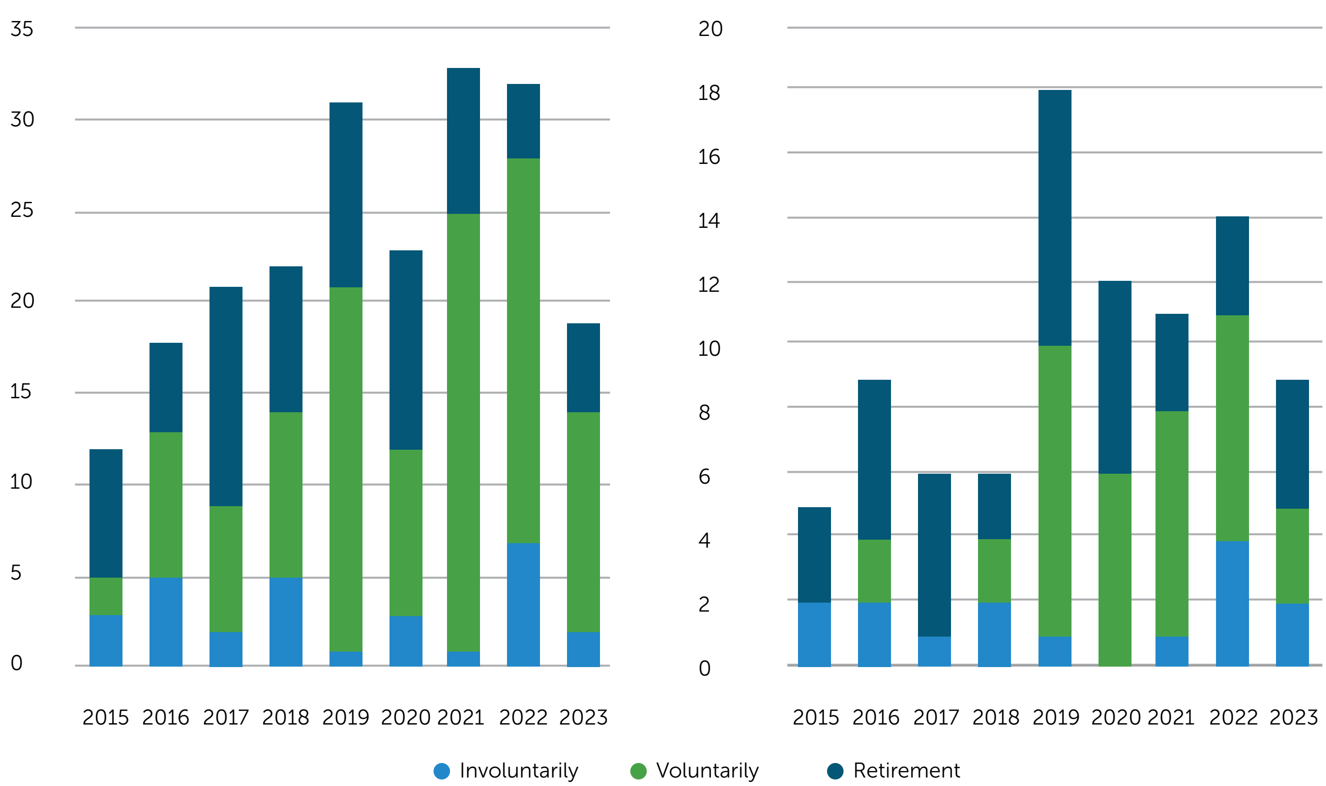



Figure 3 and Figure 4 show the historical reasons for attrition, both for Platte River as a whole and specifically for Rawhide. Retirement drives greater attrition at Rawhide than at Platte River as a whole, another trend that it anticipates will be stable through 2029. Platte River's projections for natural attrition show that it will be understaffed at Rawhide in the latter part of the decade (for example, from 2027 to 2029).

**Figure 3: Platte River Attrition by Reason**

**Figure 4: Rawhide Attrition by Reason**



Platte River projects that it will need to transition approximately 25-30 Rawhide employees at Unit 1's retirement if it backfills vacancies that arise due to retirements or other natural attrition. See Table 1. But Platte River may also fill in for natural attrition with contract labor as Unit 1's retirement date nears. Platte River will be able to better estimate the exact number of employees to transition in future years, as it clarifies the number of employees needed to support the remaining generation at Rawhide and its other departments.

**Table 1. Projected headcount and the number of employees to transition to Rawhide**

| Department | Current headcount As of Jan. 1, 2024 | Target headcount At retirement Dec. 2029 | Target headcount Post 2030 | Employees to transition |
|---|---|---|---|---|
| Plant operations | 31 | 22 | 10-15 | 7-12 |
| Mechanical maintenance | 14 | 8 | 6 | 2 |
| Instrumentation and electrical | 12 | 12 | 4 | 8 |
| Fuel handling / facilities | 12 | 5 | 4 | 1 |
| Engineering | 10 | 7 | 2 | 5 |
| Lab | 2 | 2 | 2 | 0 |
| CAD | 1 | 1 | 0 | 1 |

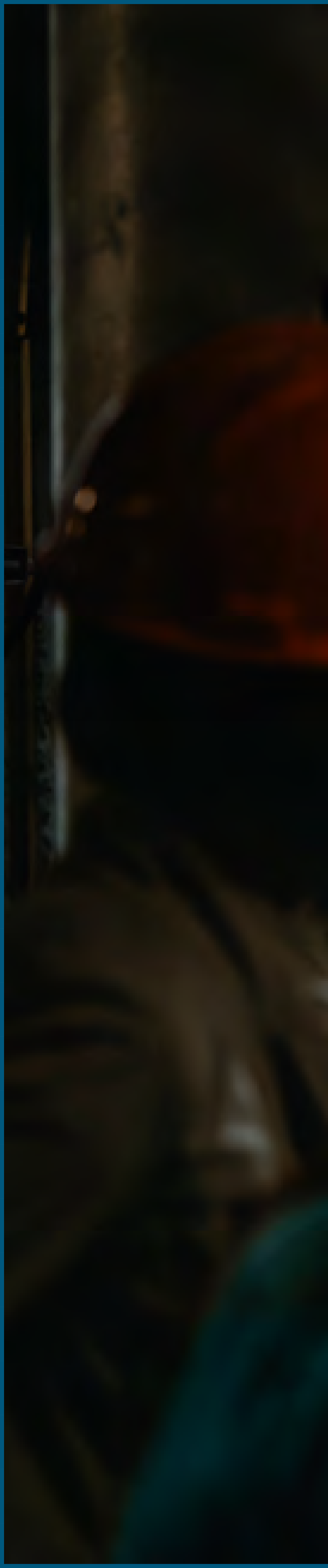
**Current headcount**
This is the number of employees at Rawhide to support Unit 1 as of May 2022. It does not include contract workers, which are managed by the vendors who employ them.

**Target headcount (at retirement)**
This is the estimated number of employees needed to safely operate Rawhide Unit 1 and the existing combustion turbines.

**Target headcount (post-2030)**
This represents the number of employees that it estimates are needed to run the existing gas combustion turbines at Rawhide after Unit 1 retires. These estimates may be updated in future filings.

**Employees to transition**
This number represents employees whose existing jobs may be eliminated due to Unit 1's retirement. Therefore, this is the number of employees to retrain, transfer within other business areas, or otherwise transition as part of the Just Transition Plan.

Platte River is committed to finding opportunities for each of these employees to remain with the organization, if desired. Platte River intends to honor its promise that no employees will be laid off or involuntarily separated solely due to Unit 1's retirement and the energy transition. How Platte River intends to meet this commitment is discussed further in the principles below.




DANGER

# PRINCIPLE 3: WORKFORCE OPPORTUNITIES

Platte River management will prioritize internal staff for workforce opportunities where Rawhide employees have relevant qualifications and experience.

To implement this principle, Platte River is identifying growth opportunities and projected work for existing employees to transition at Rawhide and at Headquarters. The main areas where Platte River sees these opportunities are:

- Power markets and marketing desks (both transmission and generation)
- Compliance
- Information Technology
- Facilities
- Substations

Each of these areas is anticipated to grow between now and 2029 due to the energy transition and Platte River's entry into RTO–West. Platte River encourages high-performing employees to reach out to their supervisors (either as part of a scheduled performance discussion or at other times) to discuss potential transition plans and opportunities. Platte River advertises all vacancies to internal employees and seeks to prioritize internal applicants for many of its open positions.

Platte River plans additional formal efforts in the upcoming years to highlight potential growth opportunities within the organization and support employee advancement and retention. These efforts include an internal "career fair" (expected in 2026) to showcase potential opportunities within the organization and to further the dialogue between departments that may lose staff and departments that need additional employees. Platte River also plans a "shadowing" program between Rawhide and headquarters so that Rawhide employees may learn more about headquarters positions that may be available, and the knowledge, skills, or abilities needed for those roles.

No later than year end 2028, Platte River plans to start formal interviews with employees to have more in-depth discussions about their goals and determine how they may align with future roles. These formal interviews will also help Platte River determine what training, education, or other support might be needed to successfully transition employees into future growth roles.

# PRINCIPLE 4: WORKFORCE TRAINING

Platte River management will provide workforce training for Rawhide employees when appropriate to allow them to successfully transition into new roles.

To implement this principle, Platte River will use the career fair, shadowing, and interview programs described above to engage with employees on how Platte River can best help employees meet their career goals.  Platte River intends to capture and analyze information learned through annual employee evaluation processes and other discussions to identify employment trends and skill gaps and to formalize training programs that are specific to the identified skill needs post-2029.

Platte River understands that training and education may be a large component of the workforce transition, particularly for employees contemplating career changes. Platte River currently has a tuition reimbursement program for employees who want to increase skills. This program is already in use with a current Rawhide employee taking courses in information technology. Platte River anticipates this program will grow significantly as it identifies skill gaps and helps employees chart career paths. Platte River is working with its staff to increase transferable skills (like computer literacy) in its current workforce. Platte River will also explore partnerships with local educational institutions in northern Colorado and southern Wyoming.These partnerships may include formal training programs tailored to the Rawhide transition or a continuation of the current tuition reimbursement program, depending on employee and Platte River needs.

# PRINCIPLE 5: RETENTION STRATEGIES

Platte River management will evaluate, design, and implement employee retention strategies to ensure Rawhide Unit 1 continues to provide safe, reliable and financially responsible energy to its owner communities until its closure date.

Platte River is committed to implementing this principle for transitioning Rawhide employees. But employee retention is not just a concern as part of the energy transition or the Just Transition Plan. Platte River seeks to be a leading employer to drive retention for all employees, at both Rawhide and headquarters, and has made many recent changes to its compensation and total employee rewards programs to support employee retention. These changes include industry-leading total rewards and compensation packages, such as:

- Platte River family leave program (providing 12 weeks fully paid family leave),
- Platte River's compensation philosophy is inclusive of a compensation study which uses a market-leading pay above the 50th percentile in 2024,
- Platte River's employee-focused benefits program, and
- Hybrid and remote work available for certain roles.

Platte River is exploring other options for retention at Rawhide up to transition, including retention bonus programs and incentives for advance retirement planning in the years leading up to Unit 1's closure. Platte River will work with its employees to evaluate and carefully implement these strategies in a way that supports the goals of continued operational excellence at Rawhide, an orderly and well planned closure, and employee transition to new roles.

# PRINCIPLE 6: TRANSITION SUPPORT

For those employees whose paths lead away from Platte River, Platte River management will seek to ease their transitions with placement support and incentives, where appropriate.

When discussing this principle, it is important to reiterate that current projections show few, if any, non-voluntary transitions due to the retirement of Rawhide Unit 1. As discussed in the first five principles, above, Platte River is committed to retaining its workforce and anticipates finding roles for Rawhide employees who want to transition to new roles after 2029. Platte River does not anticipate layoffs or other mass transitions. Platte River's Just Transition Plan supports an individualized and career-focused approach for each employee affected by Unit 1's closure.

Should any non-voluntary transitions be needed in the future due to Unit 1's retirement, Platte River is committed to supporting those employees as it supports those who transition voluntarily. Efforts will be deployed through career path discussions and ongoing training and education opportunities like those provided to employees transitioning to internal Platte River roles. Platte River also provides an employee assistance program, which is available to current employees contemplating career changes and transitions. This program may include counseling support as well as legal or financial advice to assist employees in making life changes.

# CONCLUSION

Platte River is committed to a just transition and to retaining its staff and culture of operational excellence. This document will be updated as its workforce plans evolve. Platte River will remain committed to the principles outlined by its board and management to demonstrate their unwavering support to the Platte River employees that safely and reliably operate Unit 1, its highest-performing and most cost-effective resource. Platte River looks forward to working with its staff, management, and the Office of Just Transition to responsibly move toward its energy future.

# **Appendix C:** Board resolution for 2024 IRP approval

## RESOLUTION NO. 07-24

<u>Background</u>

A. Platte River Power Authority (Platte River) was formed to provide electric generation and transmission services to its owner communities.

B. Platte River is obligated by contract to serve the owner communities' wholesale electrical capacity and energy needs through 2060.

C. Platte River and its owner communities collaborate to conduct supply-side and demand-side planning.

D. Platte River uses integrated resource planning to support its development of a resource portfolio consistent with its three foundational pillars of reliability, environmental responsibility and financial sustainability.

E. In 2018, the board of directors (board) adopted the Resource Diversification Policy, which directs Platte River's general manager/CEO to proactively work toward the goal of reaching a 100% non-carbon resource mix by 2030, while maintaining Platte River's three pillars of providing reliable, environmentally responsible and financially sustainable electricity and services.

F. By law and to remain eligible for federal hydropower allocations, Platte River must submit a formal integrated resource plan (IRP) to the Western Area Power Administration every five years. Given the challenges of quickly advancing the board's Resource Diversification Policy goals, compounded by rapid evolution of utility technology, the board encouraged staff to accelerate its formal IRP development process. Platte River staff completed and submitted its most recent IRP in 2020, and shared with the board an informal update to the IRP inputs and assumptions in 2022.

G. Platte River staff, collaborating with industry experts, has worked over the past 18 months to develop the 2024 IRP with updated studies, assumptions, technology advancements, and modeling inputs. Platte River supported community engagement through numerous in-person and virtual meetings, cataloguing and responding to stakeholder questions, and a dedicated internet microsite. Staff shared background information for the 2024 IRP with the board in April 2024 and presented a full draft of the 2024 IRP at the May 2024 board meeting.

**RESOLUTION NO. 07-24**

H. The 2024 IRP reflects existing and potential future resources based on current information, technology and system capabilities and recognizes these and other factors will continue to evolve.

I. Staff recommends selection of the 2024 IRP's optimal new carbon portfolio to establish a new baseline for planning, budgetary and ratemaking purposes.

J. The optimal carbon portfolio in the 2024 IRP provides a path for Platte River to reduce its carbon emissions by more than 90% from 2005 levels while maintaining reliability and financial sustainability, and is therefore consistent with the Resource Diversification Policy and surpasses Colorado legislative goals for greenhouse gas reductions.

K. Staff expects to prepare an updated IRP by 2028, while continuing to communicate transparently and foster public engagement in Platte River's long-term resource planning activities.

L. The board intends that when it approves the Just Transition Plan (Resolution 08-24) for the closure of Rawhide Unit 1, the Just Transition Plan will become part of the 2024 IRP.

<u>Resolution</u>

The board of directors of Platte River Power Authority therefore resolves that:

1. The 2024 IRP, as contained in the July 2024 meeting packet, is approved, and
2. Staff's recommendation to select the optimal new carbon portfolio as Platte River's new baseline for planning, budgetary and ratemaking purposes is accepted, and
3. When the board approves Platte River's Just Transition Plan for Rawhide Unit 1, the Just Transition Plan becomes part of the 2024 IRP.

AS WITNESS, I have signed my name as Secretary and have affixed the corporate seal of the Platte River Power Authority this 25 day of July 2024.

PLATTE RIVER POWER AUTHORITY CORPORATE SEAL COLORADO

Angela Walsh
Secretary

Adopted: July 25, 2024
Vote: 6-0

Platte River
Power Authority

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