Tri-State Generation and Transmission Association, Inc.

2023 Electric Resource Plan

Phase I

(Colorado Public Utilities Commission Proceeding No. 23A-____E)

December 1, 2023

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Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with 42 Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

Tri-State's Responsible Energy Plan (REP) issued in January of 2020 called for eliminating 100 percent of the carbon dioxide ("CO_2") emissions from Tri-State-owned coal generation in Colorado by 2030 and for 70 percent of the electricity used by its Members to come from clean sources by 2030. Tri-State has pursued an Electric Resource Plan (ERP) that aligns with its REP commitments.[1]

This is Tri-State's Phase I ERP. The plan complies with Colorado Public Utilities Commission (Commission) Rule 3605 and relevant paragraphs of Decision No. R22-0191 in Proceeding No. 20A-0528E issued March 28, 2022, approving the Unopposed Comprehensive Settlement Agreement (2020 ERP Settlement Agreement) filed with the Commission on January 18, 2022, concluding Phase I of Tri-State's 2020 ERP. Attachment A to this report identifies the components of this report and 2023 ERP Phase I filing that comply with Commission directives.

The 20-year[2] resource planning period (RPP) for the 2023 ERP is 2024-2043 and the resource acquisition period (RAP) is the six-year[3] period from 2026-2031. Although Tri-State evaluated "highly competitive"[4] bids for 2026 in Phase II of the 2020 ERP, given that no projects were ultimately procured, Tri-State included 2026 in the 2023 ERP RAP to assess whether additional near-term resources might be selected under updated modeling input assumptions. Tri-State selected an acquisition period of six years through 2031 to ensure that, as fossil resource retirements in Colorado occur through the end of the decade, sufficient resources would be in place to continue to meet resource adequacy and reliability requirements. The RAP also recognizes the extended lead-time for certain resource types.

Tri-State's preferred plan for its ERP is the IRA Scenario. The preferred plan is reliable, affordable, and responsible. The plan brings online 1,540 MW of new resources during the RAP, including:

- 700 MW of wind (200 MW of wind hybrids);
- 310 MW of storage (110 MW of standalone 100-hour iron air batteries; 100 MW of standalone 4-hour batteries; and 100 MW of 4-hr batteries with wind hybrids);
- 290 MW of combined-cycle natural gas in 2028 (with carbon capture and sequestration in 2031); and
- 240 MW of solar.

These resource additions are forecasted to result in the lowest present value revenue requirements (PVRR) over the planning period if Tri-State is awarded federal funding to support generation additions

[1] The REP also identifies that Tri-State is striving for 100 percent clean energy in Colorado by 2040. While Phase I of the 2023 ERP does not yet forecast achievement of that stretch goal, Tri-State will continue to strive to make progress toward this aim in Phase II of the 2023 ERP and in the 2027 ERP. Notably, 2040 remains well outside of the Resource Acquisition Period (RAP) for the 2023 ERP.
[2] Commission Rule 3602(k).
[3] Commission Rules 3602(n) and 3605(a)(IV)(A).
[4] 2020 ERP Settlement Agreement, Section 3.4.4.2.

and provide stranded asset relief under the U.S. Department of Agriculture's Empowering Rural America (New ERA) funding opportunity initiated by the Inflation Reduction Act of 2022 (IRA). The plan enables Tri-State to take full advantage of new direct pay of federal tax benefits for renewable and storage resources by increasing owned resources—while adding and maintaining PPA resources, which also helps to minimize renewable curtailment costs. The preferred plan also retires two coal-fired generation resources during the RAP, including:

- Craig Unit 3 (448 MW) on January 1, 2028; and
- Springerville Unit 3 (419 MW) on September 15, 2031.[5]

These significant shifts in Tri-State's generation portfolio over the coming years would result in an 89 percent greenhouse gas (GHG) emissions reduction related to Tri-State's wholesale sales of electricity in Colorado in 2030, over a 2005 baseline—more than any other scenario modeled in the 2023 ERP. The IRA Scenario results in the highest percentage of renewable generation capacity in 2030 (39 percent) while meeting all Level I and Level II reliability criteria, by maintaining sufficient dispatchable generation and bringing online new battery storage resources to ensure system performance during extreme weather events (EWEs).

Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data shows fourteen percent of the end-use customers served by Tri-State Members live below the federal poverty line, and up to half of the residential end-use customers suffer from some form of energy burden. The IRA has the potential to fundamentally alter the landscape for cooperative utilities. The IRA has "…tilt[ed] the balance in favor of cooperatives to develop their own renewables instead of utilizing purchase power agreements (PPAs). Thanks to the "direct-pay" provision in the law, cooperatives may now have a cost advantage depending on significant new grants from the U.S. Department of Agriculture (USDA) and the new ability to monetize tax credits that previously were available only to traditional developers with taxable income. These changes will have a big impact, as we saw when we compared renewables built by a representative cooperative versus an equivalent PPA…"[6]

Without new resource additions and assuming no change to previously announced generation retirement dates, with the exception of moving the Craig 3 retirement date to January 1, 2028, Tri-State would remain in a capacity-long position only through 2028, as identified in the 10-year loads and resources (L&R) shown in Table 1 below.[7] Under the IRA Scenario, Tri-State would remain capacity-long throughout the planning period[8], as shown in Figure 2 below.

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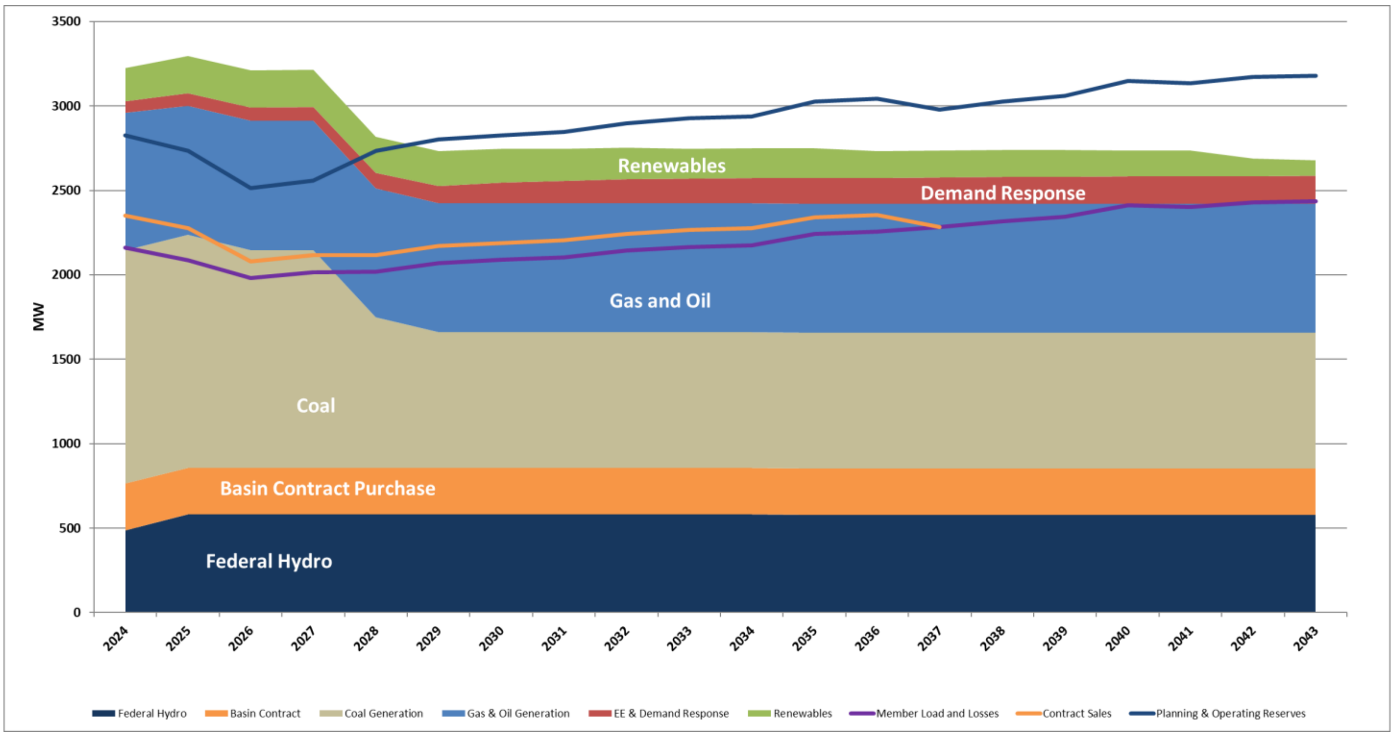
[5] Predicated on Tri-State receiving New ERA funding as requested and negotiation of contractual agreements impacted by the resource plan.
[6] https://www.mcr-group.com/wp-content/uploads/2023/06/Coops-IRA-White-Paper_v3.pdf
[7] In years where Tri-State files a Phase I ERP, the filing serves to comply with Commission Rule 3618(a) regarding ERP annual progress reports.
[8] The IRA scenario graph is reflective of all generic resources selected throughout the RPP but Tri-State will only be acquiring resources in the RAP (2026 to 2031).

Table 1: Load & Resources (L&R)[9]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3298	3212	3215	2818	2734	2746	2747	2753	2747
Total Obligations (MW)[10]	2826	2736	2516	2560	2733	2801	2827	2846	2897	2927
Excess (MW)	398	561	697	656	84	-68	-82	-99	-143	-180

Figure 1: Load & Resources (L&R)[11]



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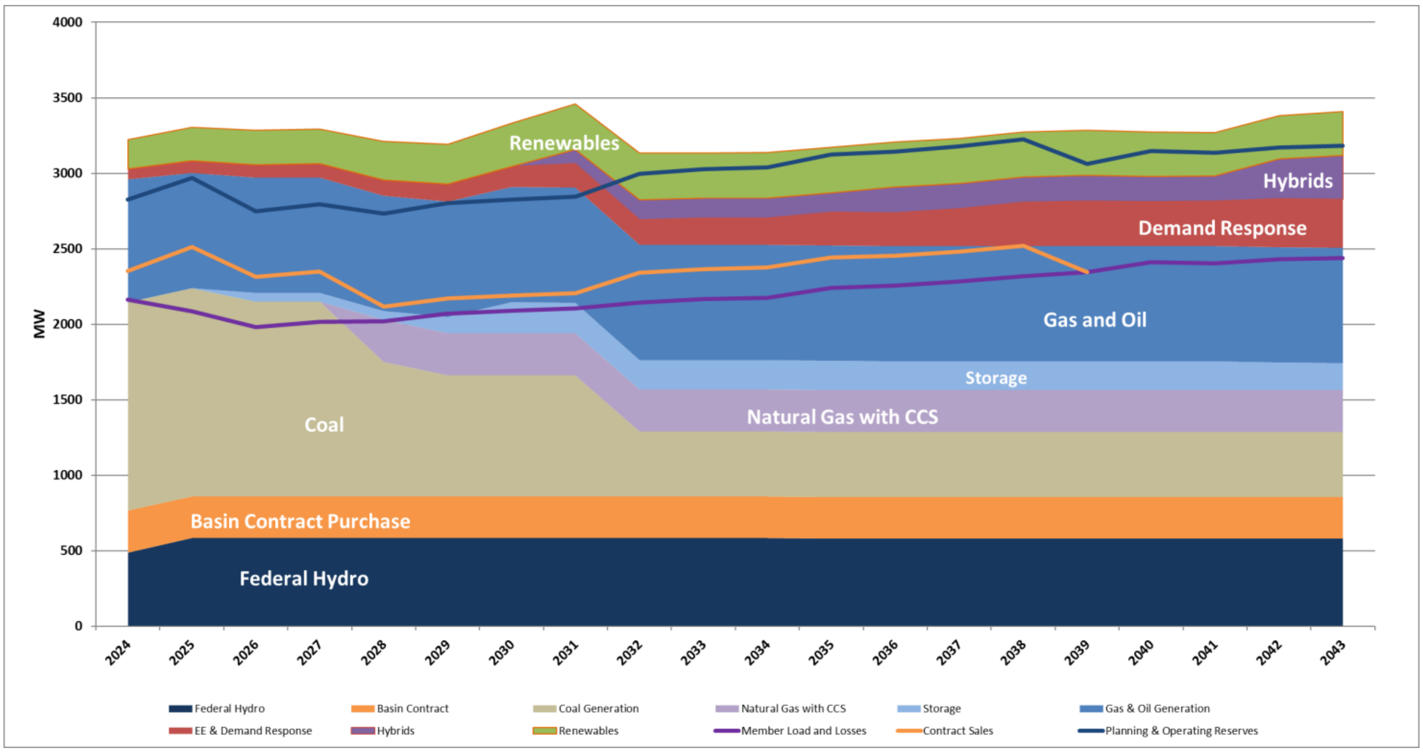
[9] No new resource additions from 2023 ERP modeling are included, reflects the current Tri-State system with known, contracted resource additions from previous procurements.
[10] Includes Member load (less energy efficiency and Partial Requirements, with Beneficial Electrification), losses, planning and operating reserves, and contract sales.
[11] No new resource additions from 2023 ERP modeling are included, reflects the current Tri-State system with known, contracted resource additions from previous procurements.

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

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3303	3286	3291	3210	3193	3332	3458	3134	3134
Total Obligations (MW)[12]	2826	2970	2750	2794	2733	2801	2827	2846	2997	3027
Excess (MW)	398	333	536	498	477	392	504	612	137	107

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



Modeling Inputs and Assumptions

Tri-State updated and modified all input assumptions for its 2023 ERP to reflect the best available information at the time modeling began in July 2023. Significant base modeling assumptions are identified and described in Attachment B and unique assumptions for each scenario are identified in Attachment B-3.

In addition to base modeling input assumptions reflective of the Tri-State system, best available information from reputable sources (such as national labs and technology vendors), and stakeholder

[12] Includes Member load (less energy efficiency and Partial Requirements, with Beneficial Electrification), losses, planning and operating reserves, and contract sales.

review and input, Tri-State also procured consultants to complete four studies that provide critical ERP inputs. The third-party completed studies are identified in Table 3 below.

Table 3: Third-Party Studies[13]

Third Party Study	Consultant	Description	Attachment
Effective Load Carrying Capability (ELCC) Study and PRM Analysis	Astrape	Determines reasonable capacity credits for wind, solar, and storage based on increasing resource penetration levels; and recommends updated planning reserve margin (PRM).	G-1
Benchmarking Study	Black & Veatch	Compares existing resources to generic resources in regard to cost and performance.	G-2
Beneficial Electrification Potential Study	Mesa Point Energy	Evaluates the achievable potential to convert non-electrical load to electrical load within Tri-State's Utility Member System territories while reducing carbon emissions.	G-3
Demand Side Management/Energy Efficiency Potential Study	Mesa Point Energy	Evaluates Demand Side Management achievable potential in relation to energy efficiency and demand response across Tri-State's Utility Member Systems' territories.	G-3
Evaluation of Tri-State G&T Preferred Plan (IRA Scenario) Reliability	Astrape	Evaluates reliability of preferred plan (IRA Scenario) in 2032	G-4

Tri-State also received input from ACES to analyze Tri-State's forward power curve forecasting and potential benefits of offering new products in an organized market, as well as related model set-up.

Assessment of Existing Resources

Tri-State's assessment of existing resources is provided in Attachment C-3. Resources capable of self-supplying certain ancillary services are identified in Attachment B-4. Information on Tri-State's PPA and contract resources is provided in Attachment C-1. An analysis of the performance of Tri-State's existing resources was performed by the third-party consultant, provided as a Benchmarking Study (Attachment G-2).

Electric Energy and Demand Forecast

Attachments F and F-1 contain Tri-State's load forecast summary and graphical presentation of load forecast data, pursuant to Commission Electric Rule 3605(a)(IV)(B) and 3605(b).

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

Scenario Modeling and Analysis Summary

Tri-State modeled five scenarios for Phase I of the 2023 ERP: 1) the Business-as-Usual (BAU), 2) IRA, 3) Early Springerville 3 Retirement (ESPV3), 4) System Wide Emissions Reductions (SWER), and 5) Aggressive Colorado Emissions Reductions (ACER). Both the BAU and IRA Scenarios include modeling input assumptions that Tri-State believes to be the most accurate and reflective of its system operations and Members' needs. Scenarios 3, 4, and 5 were modeled at the request of stakeholders.

Additionally, two[14] sensitivity analyses were performed on each scenario's expansion plan to re-dispatch the plans under extreme weather event (EWE) and high gas (HG) price conditions. The EWE sensitivity modeling assumptions are provided in Attachment B-5 and results of the EWE sensitivity analyses are provided in this report. The assumptions and results for the HG sensitivity analysis are provided in Attachment E.

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

- Wyoming / Electrically West Nebraska (WYO/WNE*)* – includes Tri-State owned or contracted resources capable of interconnecting north of TOT 3 in Wyoming and Nebraska located in the western interconnection and Western Area Colorado Missouri (WACM) Balancing Authority (BA);[15] and Tri-State load identified as WACM BA Wyoming loads.
- Eastern Colorado (ECO) – includes Tri-State owned or contracted resources capable of connecting to transmission in Colorado south of TOT 3, east of TOT 5, and in the western interconnection and WACM BA; and Tri-State load identified as WACM BA east loads and Tri-State loads in Public Service Company of Colorado (PSCO) BA.
- Western Colorado (WCO) – includes Tri-State owned or contracted resources capable of connecting to transmission in Colorado north of TOT 2, west of TOT 5, and east of TOT 1 in WACM BA; and Tri-State load identified as WACM BA west load.
- New Mexico (NM) – includes Tri-State load and owned or contracted resources physically located in or pseudo-tied into Public Service of New Mexico (PNM) BA. PNM BA is located in New Mexico and a portion of southeast Colorado.

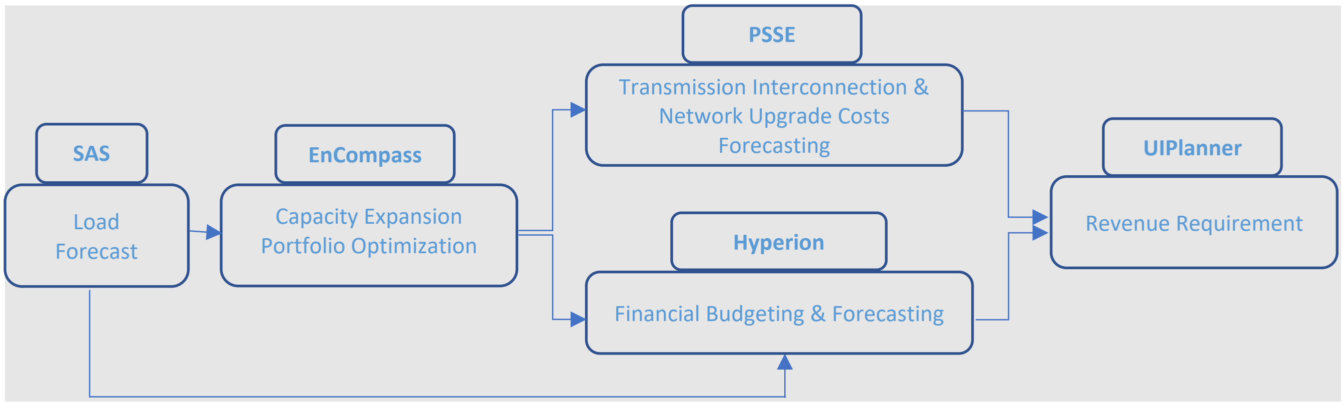
Additional detail on the Tri-State system reflected in the EnCompass model is available in Attachment B-6: Tri-State System Topology.

Figure 3 below identifies the software tools (SAS, EnCompass, PSSE, Hyperion, and UIPlanner) utilized by Tri-State for completing each component of the scenario analyses and the succession of data through each system.

[14] Tri-State contemplated performing a drought sensitivity analysis for one year of the BAU Scenario, however, at the time 2023 ERP modeling began the U.S. Bureau of Reclamation's latest five-year projection for the Colorado River system indicated 0 percent probability of minimum power pool through 2027, so Tri-State deferred drought analysis to a future ERP.

[15] TOTs represent a collection of transmission lines identified as a transfer path between regions.

Figure 3: Modeling Software Tools



Each scenario was evaluated in terms of its performance under reliability, financial, and environmental criteria, and state renewable policy compliance, as described below.

__Expansion Plan, Retirements, System Mix, and Capacity Factors__

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase I modeling, inputting the applicable modeling assumptions described in Attachment B[16] and reflecting the Tri-State system topology, provided as Attachment B-6.

__Environmental Analyses__

Based on the expansion plan and dispatch produced for each scenario, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon (SCoC) and social cost of methane (SCoM). SCoC values reflect the February 2021 Interagency Working Group (IWG) on Social Cost of Greenhouse Gases, Technical Support Document.[17]

For each scenario, Tri-State separately produced an Air Pollution Control Division (APCD) verification workbook (APCD Workbook) calculating forecasted carbon emissions reductions, provided in Attachment D.[18] Target-year emissions reductions percentages for each scenario, calculated from the APCD Workbooks, are provided in this report.

Tri-State used the most recent available EPA eGRID rates, year 2021, for forecasted market purchases and sales, the Basin Eastern Interconnection contract, and the Basin Electrically Western Interconnection contract. The carbon emission rate assumption for market purchases and sales is 1,159 pounds per MWh through 2029 per 2021 RMPA eGRID rate and 450 pounds per MWh (WECC), per APCD Workbook requirement, starting in 2030. The carbon emission rate assumption for Basin Western Interconnection contract is 2,596 pounds per MWh 2024 through 2025 per 2021 LRS eGRID rate, 1,159 pounds per MWh 2026 through 2029 per 2021 RMPA eGRID rate, and 450 pounds per MWh (WECC), per APCD Workbook

[16] *See* Attachments B, B-1, B-2, and B-3.
[17] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf
[18] 2020 ERP Settlement Agreement, Section 3.11.1.

requirement, starting in 2030. The carbon emission rate assumption for Basin Eastern Interconnection contract is 996 pounds per MWh through 2029, which is the 2021 MROW[19] eGRID rate and 525 pounds per MWh (SPP), per APCD Workbook requirement starting in 2030.

Financial Analyses

Tri-State and 39 of our 42 Members serve 170 census tracts that are identified as Disadvantaged Communities, and 161 census tracts are identified as Low Income.[20] Pursuant to Rule 3605(g)(III)(C)(iii), Tri-State provided a financial analysis of each scenario, including:

- Annual revenue requirements;
- Present value revenue requirement, with and without the social costs of carbon and methane; and
- Curtailment MWhs by intermittent resource type seasonally and year.[21]

Transmission Analyses

Each scenario was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades.

Reliability Analyses

Tri-State utilizes industry standard reliability metrics for its resource planning, referred to in the ERP as "Level I Reliability Metrics," and has also developed an additional set of reliability metrics for assessing the plan's performance under simulated EWE conditions, and refers to those standards as "Level II Reliability Metrics." All metrics are given equal weight as minimum requirement thresholds for any scenario to be supported as a reliable, preferred plan for Tri-State.

These metrics are critical for mitigating risks associated with:

- Not meeting resource adequacy obligations as a load-serving entity (LSE);
- Reliability impacts during a single EWE as well as the impact of EWEs on reliability over the course of the RAP;
- Uncertainty of performance of emerging technologies and contribution of increased intermittent resources at higher levels;
- Lost productivity and cost of deploying emergency response measures during an EWE; and
- Member reliability expectations for high reliability across the system and limited load shedding or reduced system reliability during an EWE, and over time.

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[19] Midwest Reliability Organization West

[20] Council on Environmental Quality Climate and Economic Justice Screening Tool (Explore the map - Climate & Economic Justice Screening Tool (geoplatform.gov), and USDA look-up map (Locations of Distressed and Disadvantaged Communities (arcgis.com).

[21] One of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order. In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic min and must take contracts (i.e., hydropower and Basin contracts)–in that order.

Level 1 reliability metric checks were performed on each scenario, including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%). The third-party study of PRM (Attachment G-1) was developed using a Strategic Energy Risk Valuation Model (SERVM)—a system-reliability planning and production cost model designed to analyze the capabilities of an electric system during a variety of conditions under thousands of different scenarios and is thus able to identify potential risks to system reliability across the entire year, not just at system peak. The model, therefore, provides insight into risks and costs during these periods as well as the expectation of being able to meet peak load under many, varying conditions. The results of the model help determine the amount of reserves an electric system requires to adequately maintain system reliability.
    - Target (min) is 22% transitioning to 30.5% in 2028 after the retirement of the Craig facility.
- *Loss of Load Hours (LoLH)*[22]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability).[23]
        - 2024-2033 – annually cannot exceed 2.4 hours.[24]
        - 2034-2043 – cannot exceed 24 hours over entire period.
- *Expected Unserved Energy (EUE)*[25]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.4 GWh annually.[26]

Level 2 reliability target checks were performed on each scenario's EWE sensitivity result, including:

- ≤ 12 loss of load hours during all EWEs in 2026-2031
- ≤ 3 loss of load hours per each year, 2026-2031
- EUE must be ≤ 20% of load in any hour[27]

[22] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2020 ERP Phase I.

[23] Splitting the LOLH target over the planning period reflects Tri-State's desire to have added assurance that intra-year reliability in the near-term is met by resources coming online during the RAP as the generation fleet makes significant transitions through this period. This approach also allows Tri-State to cautiously assess the impact of having an increasing percentage of intermittent resources in its fleet and the uncertain potential for more severe EWEs before applying similarly stringent LOLH metrics to the outer years of the planning period. There is more flexibility allowed in the out years as forecasting and technology uncertainty is greater during this period.

[24] The annual LOLH target of 2.4 hours is an equivalent representation of the 1 day in 10 years reliability standard.

[25] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.

[26] This metric is reflective of lower load forecasted based on both member exits and Partial Requirements and is aimed at limiting EUE to a reasonable level below the historical annual average, consistent with the 2020 ERP Phase II.

[27] This metric is an equivalent to the Level I annual EUE target, reflected as an hourly target to assess reliability during EWE stress periods. According to NREL, ~26 percent of estimated load in ERCOT was curtailed during Winter Storm Uri in 2021.

- Evaluation of market purchases vs remaining hourly available dispatchable capacity to ensure that EUE was not avoided through the use of market purchases as capacity.[28]

A detailed analysis of how additions of new intermittent capacity can serve load and maintain reliability is provided for each scenario.[29]

State Renewable Policy Compliance Analysis

Tri-State reviewed the results of each scenario and affirms that all scenarios meet or exceed the minimum applicable state renewable energy standard (RES) or renewable portfolio standard (RPS) requirements. RES/RPS standards are shown in the following table.

Table 4: Colorado RES and New Mexico RPS Requirements during RPP

	Colorado RES[30, 31]		New Mexico RPS[32]
	Co-ops	**Tri-State**	**Co-ops**
2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%

Comparative Analysis

The analysis Tri-State completed to compare and assess results across scenarios can be found in the Comparative Analysis section of this report.

Commission Electric Rule 3605(g)(III)(C) and (D)

The Commission must consider the following factors in issuing a Phase I decision:

The Phase I decision will set forth the information the utility shall provide in the ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

Tri-State proposes an outline for the ERP Implementation Report to be filed in Phase II of the 2023 ERP, provided as Attachment LKT-3.

Tri-State proposes to procure utility-owned resources and PPAs, in alignment with the resource mix modeled in the IRA Scenario, shown in the table below. This approach would result in approximately 500 MW of owned resources and 1040 MW of PPA resources.

[28] In evaluating historical events, Tri-State confirmed that there was no reliance on third party capacity during extreme weather events. If market purchases occurred an equal or greater amount of Tri-State capacity was unused.
[29] 2020 ERP Settlement Agreement, Section 3.11.14.
[30] § 40-2-124(1)(c)(I)(D) and (c)(V)(D), C.R.S.
[31] § 40-2-124(8)(b), C.R.S.
[32] N.M. Stat. Ann. § 62-15-34.

Table 5: Proposed MW of Utility-Owned and PPA Resources, by Technology, in IRA Scenario RAP

Technologies	**Own**	**PPA**
Solar		240
Wind		500
Wind Hybrid		200
4-hr Storage[33]	100	100
Iron Air Storage	110	
Natural Gas Combined Cycle (NGCC) with Carbon Capture and Sequestration (CCS) Conversion	290	
Total	**500**	**1040**

The Commission shall determine the cost of carbon dioxide emissions to assess the cost, benefit, and net present value of revenue requirements to be presented in the ERP Implementation Report.

Tri-State has utilized the most recent IWG on Social Cost of Greenhouse Gases, Technical Support Document for the SCoC at the time modeling began and suggests continuation of that practice is sufficient for reporting portfolio analysis results in Phase II of the 2023 ERP.

In consideration of the base case portfolio of resources and alternative portfolios proposed by the utility, the Commission shall define the base case portfolio and alternative portfolios for modeling in Phase II.

If New ERA funding is received as requested, Tri-State requests that the IRA Scenario be the base case portfolio in Phase II. Tri-State proposes to model one portfolio that reflects the IRA Scenario resource selections and five portfolios that identifies back-up bid selections for each technology cohort. Tri-State requests limiting stakeholder-requested portfolios to two, given the number of back-up bid portfolios that will be necessary.

The Commission may require the utility to provide information regarding alternative portfolios in addition to the base case portfolio and information regarding the cost, benefit, and net present value of revenue requirements of the alternative portfolios using different levels of costs for carbon dioxide.

Tri-State has provided cost, benefit, and PVRRs for five scenarios in Phase I, including a base case (Business as Usual Scenario), and would provide similar information for Phase II portfolios.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall establish the relevant factors other than the cost of carbon dioxide emissions for consideration of the approval of the utility's electric resource plan.

Factors that Tri-State has considered in evaluation of its preferred plan, the IRA Scenario, are identified in the Executive Summary and Comparative Analysis sections of this report. Factors include reliability, financial, and environmental considerations.

[33] Owned storage is standalone and PPA storage is tied to 200 MW of wind (wind hybrid).

The Phase I decision will establish the deadline for the utility to submit its ERP Implementation Report.

> Tri-State has proposed a Phase II timeline (Attachment LKT-2), which plans for the ERP Implementation Report to be filed 120 days after Bid Evaluation Complete (estimated to be January 2025). The proposed timeline for the ERP Implementation Report aims to ensure sufficient time for modeling preparation and completion, while recognizing RAP includes 2026.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in ongoing stakeholder engagement in advance of and during the Phase I resource planning process. Numerous stakeholder groups representing a diverse set of interests participated in more than a dozen meetings in 2023 in advance of Tri-State beginning Phase I modeling and several additional meetings during development of the Phase I filing. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform participants of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase I. These stakeholder meetings occurred between January and October 2023, covering the following topics:

1. January 17, 2023: Phase I Scope, Timeline, Generic Resources, Storage Valuation, ELCCs, Scenarios/Sensitivities, and Phase II RFP[34]
2. February 16, 2023: Beneficial Electrification (BE) Meeting #1[35]
3. February 23, 2023: Phase I Storage Valuation, ELCCs, DSM/DR/BE,[36] and Scenarios/Sensitivities[37]
4. March 10, 2023: Phase I Scenario and Sensitivity Planning #1[38]
5. March 14, 2023: Phase I Reliability and Extreme Weather Event (EWE) Sensitivities
6. March 22, 2023: BE Meeting #2[39]
7. March 24, 2023: Phase I Reliability and Extreme Weather Sensitivities
8. March 27, 2023: Phase I Scenario and Sensitivity Planning #2[40]
9. April 24, 2023: Phase I Battery Modeling and ELCC Study[41]
10. April 26, 2023: DSM Roundtable Meeting #1
11. May 4, 2023: Phase I Scenario and Sensitivity Planning #3 (GHG Reduction Modeling)[42]
12. May 17, 2023: Phase I Pre-Modeling Assumptions Feedback[43]

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[34] 2020 ERP Settlement Agreement, Sections 3.11.12., 3.11.13 and 3.11.15.
[35] 2020 ERP Settlement Agreement, Section 3.11.10.
[36] Per 2020 ERP Settlement Agreement, Sections 3.11.5, Tri-State held three meetings on DSM prior to December 31, 2022 which were identified in the 2020 ERP Phase II Implementation Report (April 27, June 14, and August 1, 2022). DSM modeling was also discussed during the February 23, 2023 stakeholder meeting.
[37] 2020 ERP Settlement Agreement, Sections 3.11.12, 3.11.13, and 3.11.14.
[38] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[39] 2020 ERP Settlement Agreement, Section 3.11.10.
[40] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[41] 2020 ERP Settlement Agreement, Section 3.11.13.
[42] 2020 ERP Settlement Agreement, Section 3.11.12.
[43] 2020 ERP Settlement Agreement, Section 3.11.12.

13. July 19, 2023: Phase I PRM, ELCC, and EWE Modeling[44]
14. August 14, 2023: Phase I Scenario and Sensitivity Planning #4[45]
15. September 27, 2023: Phase II Planning[46]
16. October 18, 2023: DSM Roundtable Meeting #2

Several other meetings, e-mail communications and updates to stakeholders also occurred in advance of and during Phase I modeling with the aim of ensuring communications on key ERP topics.[47] All 2023 ERP stakeholder meetings were identified on Tri-State's website[48] in advance of the meetings and were open for public participation.[49]

Tri-State maintains ongoing collaboration with interested stakeholders related to its ERP, federal funding pursuits, and organized market-related matters.

Scenario Results: Highlights

Key facets of the scenario modeling results, such as generic resource selection during the RAP, and unit retirements modeled and PVRRs over the RPP are summarized below. Detailed scenario results and comparisons across scenarios are in the sections that follow.

Generic Resource Selection in Scenario Modeling

Table 6 identifies the generic resource types selected across the scenarios modeled.

Table 6: Generic Resources Selected in Scenario Modeling During the RAP, by MW and Technology

Scenario	Gas	Storage[50]	Solar[51]	Wind	Wind Hybrid	Total
Scenario 1: BAU	290	250	140	0	300	**980**
Scenario 2: IRA	290	310	240	500	200	**1,540**
Scenario 3: ESPV3	290	350	140	0	300	**1,080**
Scenario 4: SWER	290	50	140	0	100	**580**
Scenario 5: ACER	290	100	140	0	200	**730**

Unit Retirement Selection in Scenario Modeling

Table 7 identifies the retirements dates modeled for resources during the RPP.

[44] 2020 ERP Settlement Agreement, Section 3.11.13.
[45] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[46] Decision No. C23-0437, at¶ 67.
[47] Of note, discussion of emissions rates occurred August 16, 2022, per 2020 ERP Settlement Agreement, Section 3.11.4, as identified in the 2020 ERP Phase II Implementation Report.
[48] https://tristate.coop/resource-planning
[49] 10 C.F.R. § 905.11(b)(4)
[50] Storage inclusive of standalone and hybrid batteries.
[51] Solar values are representative of selected generic resources during the RAP. Due to the cancellation of the Coyote Gulch after the start of modeling, 140 MW of solar replacement in 2026 will be pursued in Phase II and is reflected in this data.

Table 7: Retirements Modeled by Scenario

Scenario	Craig 3	SPV 3	LRS 2
Scenario 1: BAU	1/1/2028	1/1/2037	1/1/2043
Scenario 2: IRA	1/1/2028	9/15/2031	N/A
Scenario 3: ESPV3	1/1/2028	1/1/2031	N/A
Scenario 4: SWER	1/1/2028	1/1/2037	N/A
Scenario 5: ACER	1/1/2028	1/1/2037	1/1/2042

Scenario PVRRs

Table 8 identifies the PVRRs resulting from each scenario modeled, over the RPP.

Table 8: PVRR by Scenario

Scenario	PVRR ($, Millions)
Scenario 1: BAU	$17,507.40
Scenario 2: IRA	$16,352.00
Scenario 3: ESPV3	$17,304.20
Scenario 4: SWER	$17,343.90
Scenario 5: ACER	$17,208.20

Phase I Scenario Results and Analysis

Each section that follows presents data and analytical results from each scenario modeled, addressed in the following order:

- Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales/Purchases
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

1. Business As Usual (BAU) Scenario

The BAU Scenario and assumptions served as the base case scenario for Phase I.[52] Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 1 (BAU) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, DSM selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

[52] Commission Rule 3605(a)(IV)(M).

Table 9: Expansion Plan (Scenario 1 – BAU)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[53]	West Colorado	140	1	140
2028	NGCC with CCS[54]	West Colorado	290	1	290
2030	Wind/Battery Hybrid	East Colorado	100	2	200
	100 hr – Iron Air Battery	East Colorado	100	1	100
2031	Wind/Battery Hybrid	New Mexico	100	1	100
2032	Wind/Battery Hybrid	East Colorado	100	1	100
2033	Wind	East Colorado	100	1	100
2036	Wind/Battery Hybrid	East Colorado	100	1	100
2037	Wind/Battery Hybrid	New Mexico	100	1	100
2040	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100
2041	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100
2042	Wind/Battery Hybrid	East Colorado	100	2	200
	Wind/Battery Hybrid	Wyoming / W. Neb.	100	2	200
2043	Solar	New Mexico	100	1	100
	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[55]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[56]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 1 – BAU in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 1 – BAU in 2040.

The expansion plan also included the following Demand Response (DR) levels by region:[57]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[58]
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 1 – BAU starting in 2040.
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 1 – BAU starting in 2038.

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[53] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[54] NGCC installed in 2028 and CCS conversion startup anticipated in 2031.
[55] Commission Rule 3605(c)(I)(I).
[56] 2020 ERP Settlement Agreement at Section 3.11.6.
[57] Commission Rule 3605(c)(I)(I).
[58] 2020 ERP Settlement Agreement at Section 3.11.8.

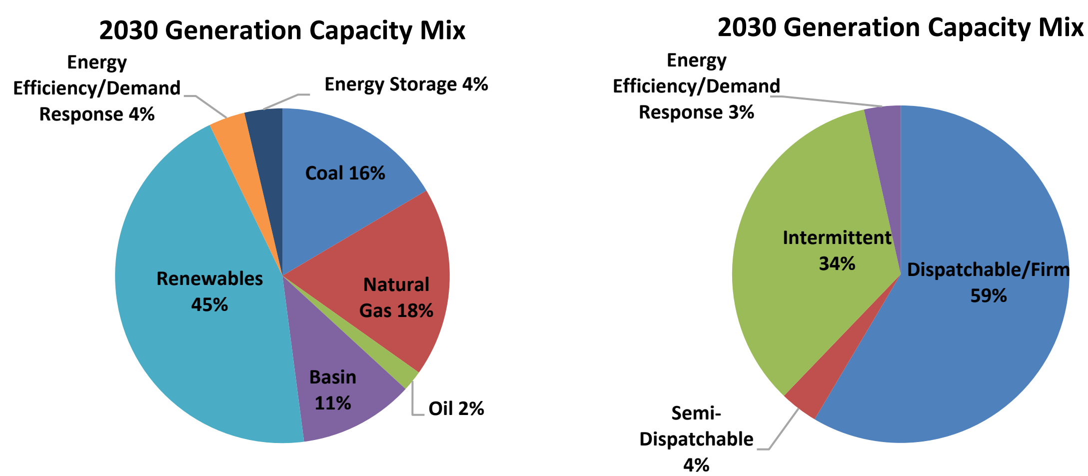
Unit retirements selected in the modeling are shown in the following table.[59]

Table 10: Modeled Retirements (Scenario 1 – BAU)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037
LRS 2 (TS portion)	241	Coal	1/1/2043[60]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 4: Projected Tri-State System Resource Mix 2030 (Scenario 1 – BAU)[61, 62, 63]



[59] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[60] This a modeling result based on input assumptions for Tri-State's portion of Laramie River Station (LRS) Unit 2; at the time of this report, Tri-State does not have the right to unilaterally retire any Missouri Basin Power Project (MBPP) resource (LRS 2 or LRS 3). Tri-State along with MBPP participants will continue to evaluate changing industry regulations, system and market conditions to inform operational decisions related to its joint owned coal units.
[61] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[62] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[63] System Energy Mix reflects sales to Members and non-Members.

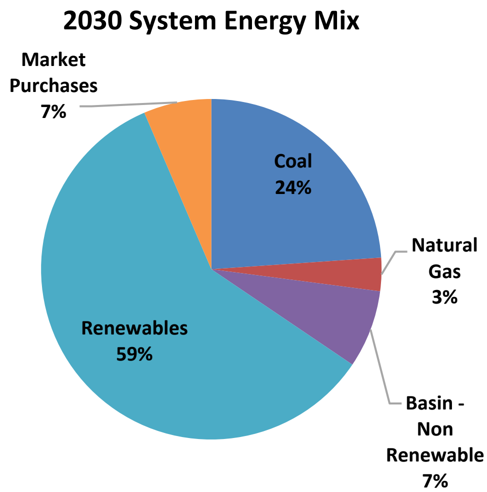


Table 11: Projected Annual Capacity Factors for Thermal Resources (Scenario 1 – BAU)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	18%	0%	0%	0%	0%	0%	0%
Craig 2	98%	15%	27%	12%	15%	0%	0%	0%
Craig 3	79%	13%	22%	18%	0%	0%	0%	0%
LRS 2	93%	89%	86%	78%	76%	74%	71%	70%
LRS 3	75%	63%	62%	55%	57%	48%	45%	51%
SPV 3	72%	67%	43%	42%	43%	36%	44%	42%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	26%	11%	0%	1%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	28%	28%	19%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 12: Forecasted Energy Sales and Purchases (Scenario 1 – BAU)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,534	1,506	3,095	2,877	3,344	2,774	3,286	3,911
Purchases (GWh)	344	946	523	884	610	717	926	742

Scenario 1 (BAU) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 13: Environmental Impact - System Wide (Scenario 1 – BAU)[64]

Year	CO_2 [65] (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,834,465	7,750	10,740	0.0383	704	6,777,851,478	32,082
2025	10,918,985	5,416	6,423	0.0243	515	4,098,496,075	20,000
2026[66]	8,555,344	5,071	5,977	0.0230	413	3,640,953,702	18,040
2027	8,004,261	4,747	5,558	0.0204	378	3,239,042,574	16,444
2028	7,398,021	4,273	4,742	0.0182	384	3,109,973,662	14,569
2029	6,751,561	3,964	4,414	0.0161	336	2,752,993,696	12,908
2030	5,884,898	4,044	4,477	0.0161	350	2,732,958,152	13,397
2031	5,745,992	4,070	4,513	0.0166	370	3,287,323,551	13,629
2032	5,310,741	3,880	4,343	0.0153	333	3,053,750,612	12,597
2033	5,652,647	4,035	4,490	0.0162	361	3,227,998,157	13,431
2034	5,698,340	4,065	4,532	0.0163	362	3,244,468,138	13,533
2035	5,458,062	3,970	4,464	0.0157	339	3,116,848,744	12,923
2036	5,083,006	3,833	4,367	0.0149	302	2,923,162,545	12,018
2037	4,083,249	3,443	4,075	0.0130	206	2,443,989,009	9,470
2038	4,101,311	3,456	4,095	0.0130	206	2,447,420,964	9,511
2039	4,167,871	3,501	4,158	0.0132	208	2,466,937,312	9,661
2040	4,173,730	3,512	4,178	0.0131	207	2,460,238,397	9,674
2041	4,163,504	3,509	4,183	0.0130	205	2,442,136,997	9,651
2042	4,205,424	3,542	4,241	0.0130	205	2,439,323,762	9,744
2043	2,858,155	2,789	3,381	0.0071	127	1,651,568,018	6,808
Total	**124,049,570**	**82,870**	**97,350**	**0.337**	**6,512**	**61,557,435,546**	**270,090**
Pounds/Gallons per MWh[67]	857	0.57	0.67	0.000002	0.04	213	2.056

[64] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.
[65] In all scenarios the 2021 eGRID emission rate for LRS is used for calculating emissions of the Basin Western Interconnection Contract in 2024 and 2025. This is a change from reporting in the 2020 ERP which used regional eGRID rates in those years. From 2026 to 2029 the 2021 RMPA eGRID is used for this contract which then transitions to the APCD assigned rate for WECC in 2030.
[66] Load reduced due to partial requirements contracts in 2026 forward.
[67] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 14: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 1 – BAU)

Year	Annual Social Cost of Carbon
2024	$1,390,597,459
2025	$995,687,914
2026	$810,659,426
2027	$787,912,259
2028	$755,247,562
2029	$714,655,955
2030	$645,736,709
2031	$653,860,869
2032	$626,587,101
2033	$691,336,216
2034	$722,286,260
2035	$716,850,786
2036	$691,597,305
2037	$575,435,014
2038	$598,539,612
2039	$629,766,814
2040	$652,840,646
2041	$670,965,445
2042	$705,605,295
2043	$494,486,160

Table 15: Social Cost of Methane Nominal Dollars – System Wide (Scenario 1 – BAU)

Year	Annual Social Cost of Methane
2024	$82,734,317
2025	$54,056,308
2026	$51,119,484
2027	$48,825,849
2028	$45,233,558
2029	$41,884,087
2030	$45,409,865
2031	$48,392,878
2032	$46,826,362
2033	$52,235,896
2034	$55,037,923
2035	$54,924,746
2036	$53,357,940
2037	$43,900,675
2038	$46,012,180
2039	$48,752,421
2040	$50,897,483
2041	$52,750,303
2042	$56,102,875
2043	$40,040,866

Table 16: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 1 – BAU)

Year	Target[68]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	68%
2030	80%	86%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 1 (BAU) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

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

Table 17: Total Financial (Scenario 1 – BAU)

$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	$17,507.4	$11,608.8	$800.2	$29,116.2	$29,916.4
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,806.8				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$598.2				

Table 18: Annual Financial (Nominal $) (Scenario 1 – BAU)

Year	Total Annual Revenue Requirement ($, Millions)
2024	$1,016
2025	$987
2026	$898
2027	$966
2028	$1,053
2029	$1,218
2030	$1,262
2031	$1,283
2032	$1,305
2033	$1,399
2034	$1,503
2035	$1,519
2036	$1,562
2037	$1,461
2038	$1,490
2039	$1,514
2040	$1,534
2041	$1,544
2042	$1,566
2043	$1,734

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 1 – BAU dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the investment tax credit (ITC) they do not have a production tax credit (PTC) penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 1 – BAU are $518,551.

Table 19: Curtailed Intermittent Energy, Annual MWh (Scenario 1 – BAU)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,653	0	0	**5,653**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**13,923**	**0**	**0**	**13,923**

Table 20: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 1 – BAU)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	125	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**150**	**11,870**	**86**	**1,817**

The following table reflects PPA pricing, penalties, and taxes.

Table 21: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 1 – BAU)

	Wind ($)	Solar ($)
2024	0	0
2025	0	0
2026	0	$208,078
2027	0	$125,060
2028	0	$102,674
2029	0	$82,738

2030	0	0
2031	0	0
RAP Total	**$0**	**$518,550**

Scenario 1 (BAU) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the point of interconnection (POI), resulting from the scenario are shown in the table below.

Table 22: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 1 – BAU)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2030	100	Wind + Battery		$2.88	
2030	100	Battery	$1.40	$2.88	
2032	100	Wind + Battery		$2.88	
2033	100	Wind		$2.88	
2036	100	Wind + Battery		$10.20	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
Wyoming (WYO) Transmission Area					
2040	100	Wind + Battery		$12.00	$109.00
2041	100	Wind		$4.20	
2042	100	Wind + Battery		$4.20	
2042	100	Wind + Battery		$4.20	$34.00
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					
2031	100	Wind + Battery		$2.88	$238.50
2037	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 1 (BAU) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 23: Planning Reserve Margin, % Annual (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	49%	42%	52%	54%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 24: Loss of Load Probability, Hours (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 25: Expected Unserved Energy, Annual MWh (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 1 – BAU)

Section 3.11.14. of the 2020 ERP Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 1 – BAU, 150 MW of 4-hour hybrid storage, 100 MW of long-duration storage, and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP, and support integration of intermittent resources.

Scenario 1 (BAU) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 26 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all twelve EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the

Scenario 1 – BAU extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours in Scenario 1 – BAU.

Table 26: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 1 – BAU)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 27 represents any EUE identified by hour in the twelve EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 27: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 1 – BAU)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed EWE performance for Scenario 1 – BAU in the post-RAP period and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 1 – BAU)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 1 – BAU, market was used for 6.4 GWh in 118 hours during the January EWE events between 2026-2031. The market was used for 11.9 GWh in 80 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

2. Inflation Reduction Act of 2022 (IRA) Scenario

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

Scenario 2 (IRA) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 28: Expansion Plan (Scenario 2 – IRA)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	4hr – Battery	New Mexico	50	1	50
	100hr – Iron Air Battery	East Colorado	10	1	10
	Solar[69]	West Colorado	140	1	140
2028	Wind	Wyoming / W. Neb.	100	2	200
	NGCC with CCS[70]	West Colorado	290	1	290
2029	Solar	New Mexico	100	1	100
	4hr – Battery	East Colorado	50	1	50
	Wind	East Colorado	100	1	100
2030	Wind	East Colorado	100	1	100
	Wind	Wyoming / W. Neb.	100	1	100
	100hr – Iron Air Battery	East Colorado	100	1	100
2031	Wind/Battery	New Mexico	100	2	200
2032	Wind/Battery	New Mexico	100	1	100
2036	Wind/Battery	East Colorado	100	1	100
2042	Wind/Battery	East Colorado	100	3	300
	Wind	Wyoming / W. Neb.	100	1	100
2043	Wind/Battery	Wyoming / W. Neb.	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[71]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[72]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 2 – IRA in 2025.

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[69] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[70] NGCC installed in 2028 and CCS conversion startup anticipated 2031.
[71] Commission Rule 3605(c)(I)(I).
[72] 2020 ERP Settlement Agreement at Section 3.11.6.

- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 2 – IRA in 2025.

The expansion plan also included the following Demand Response (DR) levels by region:[73]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[74]
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 2 – IRA starting in 2035.
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 2 – IRA starting in 2038.

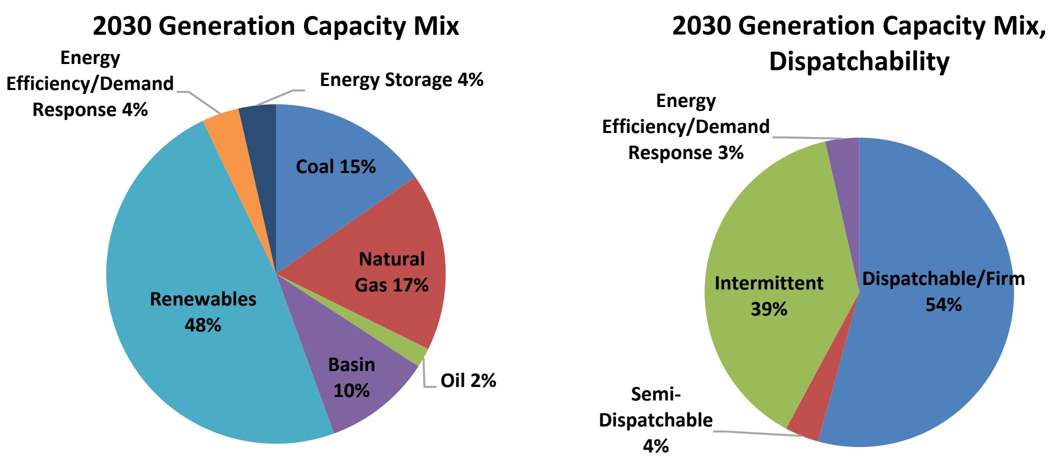
Unit retirements modeled are shown in the following table.[75]

Table 29: Modeled Retirements (Scenario 2 – IRA)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	9/15/2031

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 5: Projected Tri-State System Resource Mix 2030 (Scenario 2 – IRA)[76, 77, 78]



[73] Commission Rule 3605(c)(I)(I).
[74] 2020 ERP Settlement Agreement at Section 3.11.8.
[75] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[76] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[77] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[78] System Energy Mix reflects sales to Members and non-Members.

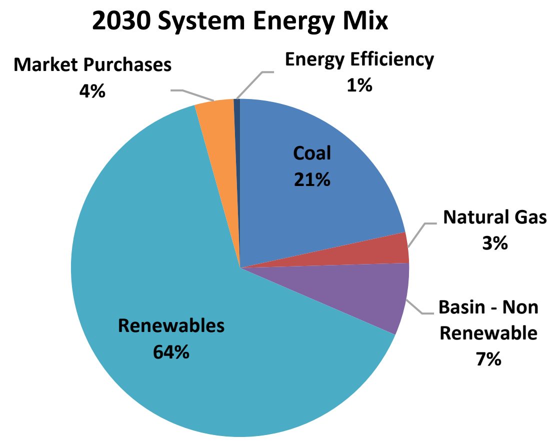


Table 30: Projected Annual Capacity Factors for Thermal Resources (Scenario 2 – IRA)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	18%	0%	0%	0%	0%	0%	0%
Craig 2	97%	16%	35%	25%	34%	0%	0%	0%
Craig 3	78%	12%	22%	17%	0%	0%	0%	0%
LRS 2	93%	89%	71%	71%	71%	68%	63%	64%
LRS 3	75%	64%	72%	60%	57%	55%	49%	50%
SPV 3	64%	66%	42%	42%	42%	36%	42%	37%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	0%	0%	0%	0%	0%	0%	0%
Shafer	26%	11%	1%	1%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	27%	25%	19%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 31: Forecasted Energy Sales and Purchases (Scenario 2 – IRA)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,304	1,499	3,067	2,873	3,957	3,883	4,259	5,014
Purchases (GWh)	283	952	515	813	422	422	542	512

Scenario 2 (IRA) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 32: Environmental Impact - System Wide (Scenario 2 – IRA)[79]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,451,106	7,595	10,593	0.0376	674	6,622,378,196	31,305
2025	10,888,923	5,401	6,381	0.0243	515	4,078,147,420	19,913
2026[80]	8,468,490	4,994	5,893	0.0225	408	3,590,666,662	17,862
2027	7,993,868	4,710	5,504	0.0204	380	3,249,891,892	16,483
2028	7,253,155	4,178	4,625	0.0178	381	3,076,352,800	14,438
2029	6,563,974	3,928	4,348	0.0163	333	2,735,998,999	12,813
2030	5,608,261	3,884	4,262	0.0155	337	2,634,907,653	12,808
2031	4,831,239	3,643	4,079	0.0145	299	2,871,821,954	11,464
2032	3,824,819	3,280	3,865	0.0122	194	2,334,603,678	8,895
2033	3,933,841	3,345	3,952	0.0125	199	2,379,546,703	9,139
2034	3,964,238	3,367	3,982	0.0126	200	2,385,882,853	9,211
2035	3,927,079	3,349	3,971	0.0123	197	2,356,788,752	9,117
2036	3,985,696	3,392	4,021	0.0125	199	2,381,021,036	9,258
2037	4,022,648	3,417	4,064	0.0125	200	2,384,355,478	9,343
2038	4,021,708	3,421	4,072	0.0125	199	2,375,788,747	9,338
2039	3,974,658	3,373	3,968	0.0128	203	2,414,033,911	9,235
2040	3,998,873	3,400	4,018	0.0127	201	2,401,751,376	9,291
2041	3,983,443	3,399	4,036	0.0124	198	2,364,432,696	9,251
2042	4,027,793	3,434	4,095	0.0124	198	2,363,931,030	9,354
2043	4,013,781	3,433	4,106	0.0122	195	2,338,232,936	9,322
Total	**114,737,592**	**78,943**	**93,836**	**0.318**	**5,707**	**57,340,534,771**	**247,837**
Pounds/Gallons per MWh[81]	792	0.55	0.65	0.000002	0.04	198	1.886

[79] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.
[80] Load reduced due to partial requirements contracts in 2026 forward.
[81] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

123055698.2

Table 33: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 2– IRA)

Year	Annual Social Cost of Carbon
2024	$1,356,930,446
2025	$992,946,534
2026	$802,429,547
2027	$786,889,198
2028	$740,458,538
2029	$694,799,728
2030	$615,381,995
2031	$549,767,216
2032	$451,270,783
2033	$481,120,934
2034	$502,482,209
2035	$515,774,643
2036	$542,296,523
2037	$566,894,764
2038	$586,922,384
2039	$600,572,264
2040	$625,490,158
2041	$641,947,763
2042	$675,801,518
2043	$694,419,551

Table 34: Social Cost of Methane Nominal Dollars – System Wide (Scenario 2 – IRA)

Year	Annual Social Cost of Methane
2024	$80,730,077
2025	$53,818,969
2026	$50,613,362
2027	$48,939,435
2028	$44,826,979
2029	$41,577,985
2030	$43,413,041
2031	$40,707,122
2032	$33,064,168
2033	$35,541,561
2034	$37,457,706
2035	$38,749,984
2036	$41,103,874
2037	$43,309,094
2038	$45,174,789
2039	$46,600,954
2040	$48,883,426
2041	$50,563,745
2042	$53,858,083
2043	$54,827,634

Table 35: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 2 – IRA)

Year	Target[82]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	67%
2030	80%	89%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 2 (IRA) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

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

Table 36: Total Financial (Scenario 2 – IRA)

$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	$16,352.0	$10,726.7	$733.1	$27,078.7	$27,811.8
Expansion Plan CapEx + IDC: Generation (Nominal $)	$2,093.9				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$555.5				

Table 37: Annual Financial (Nominal $) (Scenario 2 – IRA)

Year	Total Annual Revenue Requirement ($, Millions)
2024	$1,011
2025	$968
2026	$870
2027	$928
2028	$1,001
2029	$1,073
2030	$1,144
2031	$1,204
2032	$1,267
2033	$1,287
2034	$1,313
2035	$1,333
2036	$1,357
2037	$1,379
2038	$1,404
2039	$1,433
2040	$1,459
2041	$1,494
2042	$1,519
2043	$1,546

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

*Table 38: Total Financial Under **EWE** Sensitivity (Scenario 2 – IRA)*

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

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 2 – IRA dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 2 – IRA are $503,718.

Table 39: Curtailed Intermittent Energy, Annual MWh (Scenario 2– IRA)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	75	0	0	**75**
2027	0	0	0	0	**0**
2028	0	287	0	0	**287**
2029	0	583	0	1,197	**1,780**
2030	0	376	0	203	**579**
2031	0	632	154	3,633	**4,419**
RAP Total	**0**	**1,953**	**154**	**5,033**	**7,140**

Table 40: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 2 – IRA)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	0	75	0	0
2027	0	0	0	0
2028	7	280	0	0
2029	1	1,572	0	207
2030	0	579	0	0
2031	0	3,902	13	504
RAP Total	**8**	**6,408**	**13**	**711**

The following table reflects PPA pricing, penalties, and taxes.

Table 41: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 2 – IRA)

	Wind ($)	Solar ($)
2024	0	0
2025	0	0
2026	0	$2,816
2027	0	$0
2028	0	$9,596
2029	0	$122,947
2030	0	$29,692
2031	$8,765	$329,902
RAP Total	**$8,765**	**$494,953**

Scenario 2 (IRA) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 42: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 2 – IRA)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2026	10	Battery	$1.40	$2.88	
2029	50	Battery	$1.40	$2.88	
2029	100	Wind		$2.88	
2030	100	Wind		$2.88	
2030	100	Battery	$1.40	$2.88	
2036	100	Wind + Battery		$2.88	
2042	100	Wind		$10.20	
2042	100	Wind		$2.88	
2042	100	Wind		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
Wyoming (WYO) Transmission Area					
2028	100	Wind		$12.00	$109.00
2028	100	Wind		$4.20	
2030	100	Wind		$4.20	
2042	100	Wind		$4.20	$26.00
2043	100	Wind + Battery		$4.50	
New Mexico (NM) Transmission Area)					
2026	50	Battery		$2.88	
2029	100	Solar		$1.68	
2031	100	Wind + Battery		$2.88	$238.50

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2031	100	Wind + Battery		$2.88	
2032	100	Wind + Battery		$2.88	

Scenario 2 (IRA) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 43: Planning Reserve Margin, % Annual (Scenario2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	49%	47%	54%	50%	55%	60%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 44: Loss of Load Probability, Hours (Scenario 2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
0	1	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 45: Expected Unserved Energy, Annual MWh (Scenario 2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
0	1	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 2 – IRA)

Section 3.11.14. of the 2020 ERP Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 2 – IRA, 200 MW of short duration storage, 110 MW of long duration storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 2 (IRA) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 46: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 2– IRA)Table 46 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all twelve EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 46: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 2– IRA)

Event (Season/Year)	Date	Hour
All Event Periods	N/A	N/A

Table 47 represents any EUE identified by hour in the twelve EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 47: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 2 – IRA)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All Event Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 2 –IRA)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 2 – IRA, the market was used for 5.5 GWh in 97 hours during the January EWE events between 2026-2031. The market was used for 11.5 GWh in 79 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics.

Market purchases during these limited hours were confirmed to not lean on the market for capacity.

3. Early Springerville 3 Retirement Scenario (ESPV3)

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

Scenario 3 (ESPV3) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 48: Expansion Plan (Scenario 3 – ESPV3)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[83]	West Colorado	140	1	140
2028	4hr – Battery	West Colorado	50	1	50
	NGCC with CCS[84]	West Colorado	290	1	290
2030	Wind/Battery	East Colorado	100	1	100
2031	4hr – Battery	West Colorado	50	1	50
	Wind/Battery	New Mexico	100	2	200
	100hr – Iron Air Battery	East Colorado	100	1	100
2036	Wind	East Colorado	100	1	100
2037	Wind	East Colorado	100	2	200
2039	Wind/Battery	Wyoming / W. Neb.	100	1	100
2040	Wind/Battery	Wyoming / W. Neb.	100	1	100
2041	Wind	Wyoming / W. Neb.	100	2	200
2042	Wind/Battery	East Colorado	100	3	300
2043	Solar	New Mexico	100	1	100
	Wind/Battery	Wyoming / W. Neb	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[85]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[86]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 3 – ESPV3 in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 3 – ESPV3 in 2040.

[83] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[84] NGCC installed in 2028 and CCS conversion startup anticipated in 2031.
[85] Commission Rule 3605(c)(I)(I).
[86] 2020 ERP Settlement Agreement at Section 3.11.6.

The expansion plan also included the following Demand Response (DR) levels by region:[87]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[88]
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 3 – ESPV3 starting in 2031.
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 3 – ESPV3 starting in 2031

Unit retirements selected in the modeling are shown in the following table.[89]

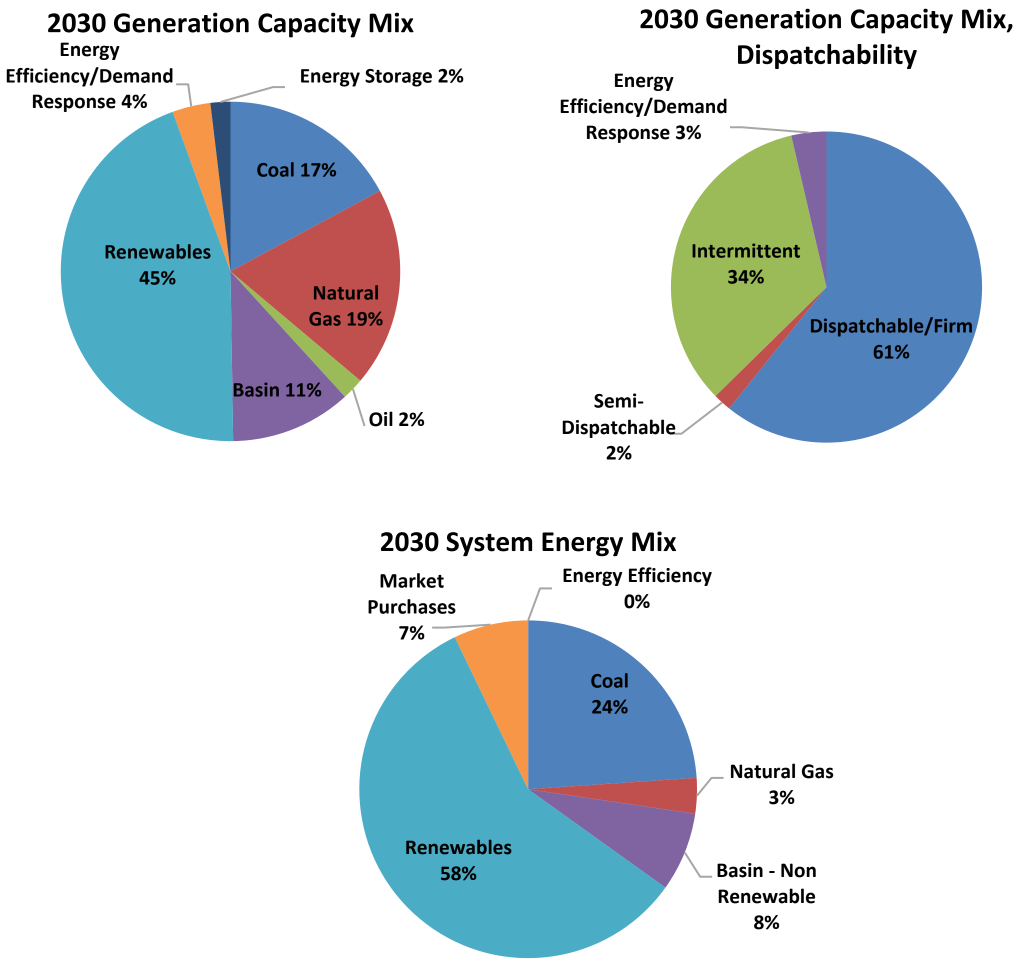
Table 49: Modeled Retirements (Scenario 3 –ESPV3)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2031

Resulting system capacity and energy mix, based on the modeling are shown below.

[87] Commission Rule 3605(c)(I)(I).
[88] 2020 ERP Settlement Agreement at Section 3.11.8.
[89] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (“Yampa Project Owners”).

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



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[90] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.

[91] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.

[92] System Energy Mix reflects sales to Members and non-Members.

Table 50: Projected Annual Capacity Factors for Thermal Resources (Scenario 3 – ESPV3)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	16%	0%	0%	0%	0%	0%	0%
Craig 2	98%	9%	34%	23%	20%	0%	0%	0%
Craig 3	79%	14%	22%	16%	0%	0%	0%	0%
LRS 2	93%	89%	71%	71%	71%	69%	63%	64%
LRS 3	75%	64%	70%	60%	58%	51%	48%	54%
SPV 3	72%	67%	43%	42%	43%	37%	44%	0%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	24%	11%	1%	0%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	29%	28%	20%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 51: Forecasted Energy Sales and Purchases (Scenario 3 – ESPV3)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,505	1,506	3,044	2,850	3,312	2,712	3,018	3,098
Purchases (GWh)	355	946	545	852	623	722	1,004	1,167

Scenario 3 (ESPV3) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 52: Environmental Impact - System Wide (Scenario 3 – ESPV3)[93]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,839,102	7,764	10,741	0.0383	704	6,772,194,117	32,129
2025	10,919,154	5,447	6,450	0.0245	513	4,099,792,207	19,995
2026[94]	8,469,494	4,985	5,874	0.0224	409	3,579,117,374	17,834
2027	7,999,822	4,707	5,493	0.0203	381	3,238,736,958	16,456
2028	7,332,465	4,209	4,671	0.0177	380	3,069,522,031	14,392
2029	6,711,585	3,942	4,388	0.0160	333	2,727,887,902	12,834
2030	5,808,252	3,998	4,428	0.0157	345	2,680,280,773	13,221

[93] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[94] Load reduced due to partial requirements contracts in 2026 forward.

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2031	3,936,370	3,337	3,931	0.0126	201	2,399,903,106	9,134
2032	3,835,588	3,290	3,891	0.0121	193	2,324,000,130	8,911
2033	3,950,512	3,360	3,986	0.0124	198	2,369,472,111	9,166
2034	3,982,627	3,382	4,019	0.0125	199	2,377,578,327	9,240
2035	3,951,406	3,370	4,016	0.0122	196	2,345,304,444	9,165
2036	4,026,737	3,423	4,077	0.0125	199	2,380,608,886	9,347
2037	4,060,785	3,435	4,078	0.0128	203	2,416,104,215	9,428
2038	4,051,989	3,435	4,086	0.0126	201	2,399,586,707	9,406
2039	4,098,100	3,460	4,108	0.0129	204	2,432,494,784	9,515
2040	4,094,950	3,467	4,124	0.0128	203	2,419,226,942	9,510
2041	4,088,441	3,459	4,110	0.0128	203	2,420,432,239	9,492
2042	4,131,169	3,499	4,190	0.0127	201	2,399,136,160	9,588
2043	4,099,795	3,483	4,170	0.0125	199	2,380,264,589	9,520
Total	**115,388,344**	**79,453**	**94,833**	**0.318**	**5,667**	**57,231,644,003**	**248,282**
Pounds/Gallons per MWh[95]	797	0.55	0.65	0.000002	0.04	198	1.890

Table 53: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 3 – ESVP3)

Year	Annual Social Cost of Carbon
2024	$1,391,004,648
2025	$995,703,293
2026	$802,524,764
2027	$787,475,263
2028	$748,555,145
2029	$710,424,496
2030	$637,326,494
2031	$447,936,321
2032	$452,541,393
2033	$483,159,901
2034	$504,813,123
2035	$518,969,660
2036	$547,880,617
2037	$572,269,158
2038	$591,341,514
2039	$619,224,271
2040	$640,518,145
2041	$658,868,730
2042	$693,146,438
2043	$709,300,764

[95] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 54: Social Cost of Methane Nominal Dollars – System Wide (Scenario 3 – ESPV3)

Year	Annual Social Cost of Methane
2024	$82,855,374
2025	$54,041,930
2026	$50,535,594
2027	$48,861,264
2028	$44,684,056
2029	$41,645,072
2030	$44,814,668
2031	$32,432,806
2032	$33,124,403
2033	$35,647,372
2034	$37,577,397
2035	$38,954,135
2036	$41,497,117
2037	$43,705,831
2038	$45,503,307
2039	$48,013,151
2040	$50,034,448
2041	$51,880,457
2042	$55,205,912
2043	$55,991,156

Table 55: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 3 – ESPV3)

Year	Target[96]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	67%
2030	80%	85%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 3 (ESPV3) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[96] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Table 56: Total Financial (Scenario 3 – ESPV3)

$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	$17,304.2	$10,789.6	$734.8	$28,093.8	$28,828.6
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,983.6				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$590.6				

Table 57: Annual Financial (Nominal $) (Scenario 3 – ESPV3)

Year	Total Annual Revenue Requirement ($, Millions)
2024	$1,016
2025	$988
2026	$904
2027	$962
2028	$1,060
2029	$1,178
2030	$1,441
2031	$1,335
2032	$1,345
2033	$1,361
2034	$1,382
2035	$1,404
2036	$1,428
2037	$1,450
2038	$1,474
2039	$1,495
2040	$1,514
2041	$1,529
2042	$1,546
2043	$1,562

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 3 – ESPV3 dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 3 – ESPV3 are $520,955.

Table 58: Curtailed Intermittent Energy, Annual MWh (Scenario 3 – ESPV3)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,640	0	0	**5,640**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	44	0	**44**
RAP Total	**0**	**13,910**	**44**	**0**	**13,954**

Table 59: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 3 – ESPV3)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	112	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	44	0	0
RAP Total	**137**	**11,914**	**86**	**1,817**

The following table reflects PPA pricing, penalties, and taxes.

Table 60: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 3 – ESPV3)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$208,309
2027	$0	$124,914
2028	$0	$102,651
2029	$0	$82,570

2030	$0	$0
2031	$2,511	$0
RAP Total	**$2,511**	**$518,444**

Scenario 3 (ESPV3) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 61: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 3 – ESPV3)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2031	100	Battery	$1.40	$2.88	
2036	100	Wind		$10.20	
2037	100	Wind		$2.88	
2037	100	Wind		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
2028	50	Battery	$1.40	$2.88	
2031	50	Battery	$1.40	$2.88	
Wyoming (WYO) Transmission Area					
2039	100	Wind + Battery		$12.00	$109.00
2040	100	Wind + Battery		$4.20	
2041	100	Wind		$4.20	
2041	100	Wind		$4.20	$26.00
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					
2031	100	Wind + Battery		$2.88	$238.50
2031	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 3 (ESPV3) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 62: Planning Reserve Margin, % Annual (Scenario 3 –ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	52%	44%	47%	48%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 63: Loss of Load Probability, Hours (Scenario 3 – ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 64: Expected Unserved Energy, Annual MWh (Scenario 3 – ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 3 – ESPV3)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 3 – ESPV3, 250 MW of 4-hr storage, 100 MW of long-duration storage, and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 3 (ESPV3) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 65 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 65: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 3 – ESPV3)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 66 represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 66: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 3 – ESPV3)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 3 – ESPV3)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 3—ESPV3, the market was used for 7.4 GWh in 131 hours during the January EWE events between 2026-2031. The market was used for 14.3 GWh in 85 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

4. System-wide Emissions Reduction Scenario (SWER)

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

Scenario 4 (SWER) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 67: Expansion Plan (Scenario 4 – SWER)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[97]	West Colorado	140	1	140
2029	NGCC with CCS[98]	West Colorado	290	1	290
2030	Wind/Battery	East Colorado	100	1	100
2033	Wind	New Mexico	100	1	100
	Wind/Battery	New Mexico	100	1	100
2034	Wind/Battery	East Colorado	100	1	100
2036	Wind/Battery	East Colorado	100	1	100
2037	Wind/Battery	New Mexico	100	1	100
2038	Wind/Battery	East Colorado	100	1	100
2040	Wind/Battery	Wyoming / W. Neb.	100	1	100
2041	Wind	Wyoming / W. Neb.	100	2	200
2042	Wind	East Colorado	100	1	100
	Wind/Battery	East Colorado	100	2	200
2043	Solar – Build Transfer	West Colorado	100	3	300
	Solar	New Mexico	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[99]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[100]

[97] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[98] NGCC installed in 2029 and CCS conversion startup anticipated in 2031.
[99] Commission Rule 3605(c)(I)(I).
[100] 2020 ERP Settlement Agreement at Section 3.11.6.

The expansion plan also included the following Demand Response (DR) levels by region:[101]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[102]
- 39 MW of Wyoming low level Demand Response was selected in the expansion plan of Scenario 4 – SWER starting in 2030.
- 117 MW New Mexico moderate level Demand Response was selected in the expansion plan of Scenario 4 – SWER starting in 2039.

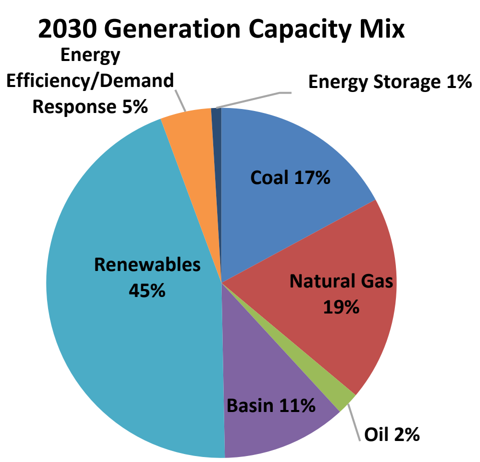
Unit retirements selected in the modeling are shown in the following table.[103]

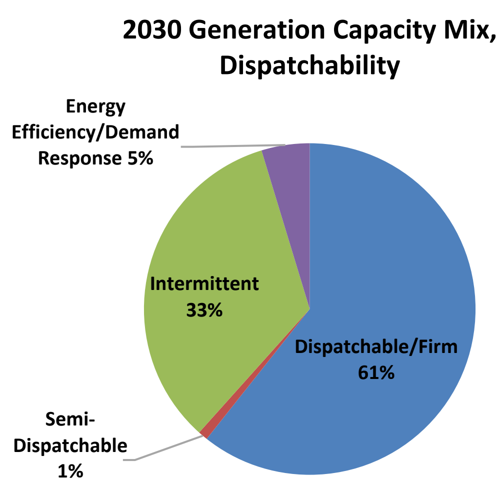
Table 68: Modeled Retirements (Scenario 4 – SWER)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 7: Projected Tri-State System Resource Mix 2030 (Scenario 4- SWER)[104, 105, 106]





[101] Commission Rule 3605(c)(I)(I).
[102] 2020 ERP Settlement Agreement at Section 3.11.8.
[103] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[104] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[105] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[106] System Energy Mix reflects sales to Members and non-Members.

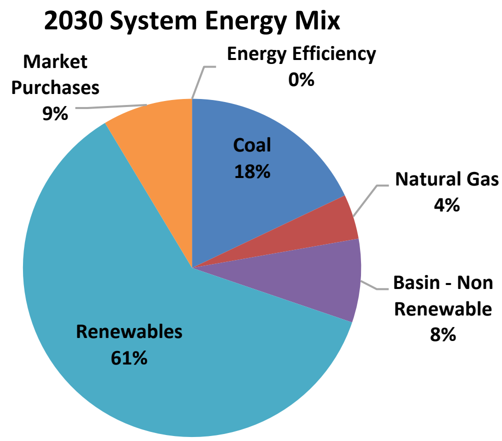


Table 69: Projected Annual Capacity Factors for Thermal Resources (Scenario 4 - SWER)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	17%	0%	0%	0%	0%	0%	0%
Craig 2	98%	16%	26%	13%	36%	0%	0%	0%
Craig 3	79%	13%	25%	19%	0%	0%	0%	0%
LRS 2	93%	89%	71%	72%	71%	67%	41%	16%
LRS 3	75%	64%	69%	57%	58%	50%	30%	13%
SPV 3	72%	67%	43%	42%	45%	36%	37%	36%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	27%	11%	0%	1%	1%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	0%	29%	24%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 70: Forecasted Energy Sales and Purchases (Scenario 4 – SWER)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,561	1,496	3,063	2,872	2,902	2,615	2,245	1,687
Purchases (GWh)	346	941	550	912	748	658	1,154	1,265

Scenario 4 (SWER) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 71: Environmental Impact - System Wide (Scenario 4 - SWER)[107]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,863,704	7,761	10,763	0.0383	705	6,793,247,708	32,133
2025	10,919,812	5,420	6,407	0.0244	516	4,098,699,996	19,995
2026[108]	8,477,517	5,026	5,962	0.0225	404	3,583,422,154	17,903
2027	7,972,529	4,721	5,542	0.0202	374	3,210,051,302	16,365
2028	7,358,120	4,302	4,787	0.0182	377	2,927,811,446	14,845
2029	6,573,723	3,872	4,303	0.0156	327	2,680,149,760	12,556
2030	4,514,050	3,295	3,646	0.0108	262	1,990,503,327	10,296
2031	3,157,659	2,666	2,918	0.0062	212	1,818,549,023	7,869
2032	3,203,866	2,736	3,048	0.0067	205	1,845,960,399	7,905
2033	3,208,225	2,703	2,972	0.0063	213	1,829,638,245	7,985
2034	3,226,798	2,710	2,973	0.0064	215	1,851,008,307	8,024
2035	3,254,631	2,763	3,078	0.0069	208	1,876,225,341	8,012
2036	3,315,308	2,850	3,219	0.0077	200	1,929,252,664	8,076
2037	3,614,749	3,177	3,763	0.0110	179	2,178,755,684	8,428
2038	3,622,455	3,180	3,760	0.0111	181	2,189,879,374	8,448
2039	3,611,385	3,180	3,770	0.0110	178	2,169,009,462	8,423
2040	3,596,535	3,182	3,782	0.0108	176	2,145,151,059	8,397
2041	3,613,093	3,188	3,781	0.0109	178	2,160,677,499	8,433
2042	3,585,634	3,191	3,825	0.0104	171	2,091,352,778	8,369
2043	3,610,874	3,196	3,807	0.0107	175	2,135,484,251	8,432
Total	**106,300,669**	**73,119**	**86,106**	**0.266**	**5,456**	**51,504,829,781**	**230,898**
Pounds/Gallons per MWh[109]	734	0.50	0.59	0.000002	0.04	178	1.757

[107] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.
[108] Load reduced due to partial requirements contracts in 2026 forward.
[109] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 72: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 4 – SWER)

Year	Annual Social Cost of Carbon
2024	$1,393,165,248
2025	$995,763,266
2026	$803,284,931
2027	$784,788,638
2028	$751,174,190
2029	$695,831,712
2030	$495,316,652
2031	$359,323,495
2032	$378,007,746
2033	$392,375,842
2034	$409,008,952
2035	$427,456,666
2036	$451,083,112
2037	$509,411,285
2038	$528,656,041
2039	$545,681,555
2040	$562,557,798
2041	$582,264,404
2042	$601,614,118
2043	$624,713,086

Table 73: Social Cost of Methane Nominal Dollars – System Wide (Scenario 4 - SWER)

Year	Annual Social Cost of Methane
2024	$82,867,370
2025	$54,042,415
2026	$50,729,638
2027	$48,591,361
2028	$46,092,106
2029	$40,743,674
2030	$34,900,045
2031	$27,942,182
2032	$29,384,966
2033	$31,054,907
2034	$32,634,103
2035	$34,054,127
2036	$35,858,109
2037	$39,068,247
2038	$40,865,813
2039	$42,504,595
2040	$44,182,882
2041	$46,091,559
2042	$48,190,439
2043	$49,596,337

Table 74: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 4 - SWER)

Year	Target[110]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	68%
2030	80%	82%

Table 75: System-wide GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 4 - SWER)

Year	Target[111]	Forecast
2027	20.9%	44%
2028	33.2%	44%
2029	45.4%	51%
2030	57.7%	61%
2031	70%	73%

See Appendix D for detailed GHG emissions calculations for the scenario.

[110] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.
[111] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Scenario 4 (SWER) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

Table 76: Total Financial (Scenario 4 - SWER)

$, Millions	**Scenario PVRR** (2023 WACC 4.12%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Scenario PVRR inclusive of SCoC NPV**	**Scenario PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,343.9	$9,899.2	$679.1	$27,243.1	$27,922.2
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,694.1				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$546.3				

Table 77: Annual Financial (Nominal $) (Scenario 4 - SWER)

Year	**Total Annual Revenue Requirement ($, Millions)**
2024	$1,016
2025	$978
2026	$894
2027	$957
2028	$1,003
2029	$1,092
2030	$1,232
2031	$1,270
2032	$1,434
2033	$1,459
2034	$1,497
2035	$1,512
2036	$1,534
2037	$1,421
2038	$1,445
2039	$1,497
2040	$1,518
2041	$1,536
2042	$1,557
2043	$1,730

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 4 – SWER dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 4 – SWER are $531,366.

Table 78: Curtailed Intermittent Energy, Annual MWh (Scenario 4 - SWER)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,854	0	0	**5,854**
2027	0	3,378	0	0	**3,378**
2028	0	2,821	0	0	**2,821**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**14,246**	**0**	**0**	**14,246**

Table 79: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 4 - SWER)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	258	4,515	20	1,061
2027	0	3,057	45	276
2028	114	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**372**	**11,970**	**87**	**1,817**

The following table reflects PPA pricing, penalties, and taxes.

Table 80: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 4 - SWER)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$216,270
2027	$0	$126,321
2028	$0	$106,117
2029	$0	$82,658
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$531,366**

Scenario 4 (SWER) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 81: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 4 - SWER)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2034	100	Wind + Battery		$2.88	
2036	100	Wind + Battery		$2.88	
2038	100	Wind + Battery		$2.88	
2042	100	Wind		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2029	290	Gas	$1.50	$4.20	
2043	100	Solar		$2.88	
2043	100	Solar		$2.88	
2043	100	Solar		$1.68	
Wyoming (WYO) Transmission Area					
2040	100	Wind + Battery		$12.00	$109.00
2041	100	Wind		$4.20	
2041	100	Wind		$4.20	
New Mexico (NM) Transmission Area)					
2033	100	Wind		$2.88	$238.50

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind + Battery		$2.88	
2037	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 4 (SWER) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 82: Planning Reserve Margin, % Annual (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	35%	42%	46%	45%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 83: Loss of Load Probability, Hours (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 84: Expected Unserved Energy, Annual MWh (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 4 - SWER)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 4 – SWER, 50 MW of short duration storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

123055698.2

Scenario 4 (SWER) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 85 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 85: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 4 – SWER)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 86 represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 86: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 4 – SWER)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 4 – SWER)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 4 – SWER, the market was used for 7.3 GWh in 133 hours during the January EWE events between 2026-2031. The market was used for 17 GWh in 99 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

5. Aggressive Colorado Emissions Reductions Scenario (ACER)

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

Scenario 5 (ACER) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 87: Expansion Plan (Scenario 5 - ACER)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[112]	West Colorado	140	1	140
2029	Wind/Battery	East Colorado	100	1	100
2030	NGCC with CCS[113]	West Colorado	290	1	290
2031	Wind/Battery	Wyoming / W. Neb.	100	1	100
2033	Wind	East Colorado	100	2	200
2035	Wind/Battery	East Colorado	100	1	100
2037	Wind/Battery	East Colorado	100	1	100
	Wind/Battery	New Mexico	100	2	200
2040	Wind/Battery	Wyoming / W. Neb.	100	2	200
	Solar – Build Transfer	West Colorado	100	2	200
2042	Wind/Battery	East Colorado	100	4	400
	Wind/Battery	Wyoming / W. Neb.	100	3	300
2043	Wind/Battery	Wyoming / W. Neb.	100	1	100
	Solar	New Mexico	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[114]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[115]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 5 – ACER in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 5 – ACER in 2040.

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112 This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
113 NGCC installed in 2030 and CCS conversion startup anticipated in 2031.
114 Commission Rule 3605(c)(I)(I).
115 2020 ERP Settlement Agreement at Section 3.11.6.

The expansion plan also included the following Demand Response (DR) levels by region:[116]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[117]
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 5 - ACER in 2038
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 5 – ACER starting in 2042.

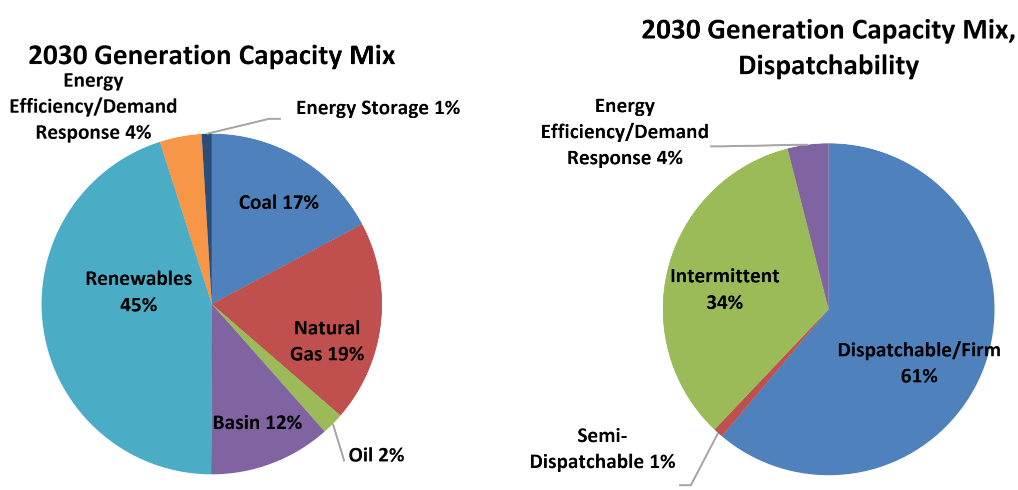
Unit retirements selected in the modeling are shown in the following table.[118]

Table 88: Modeled Retirements (Scenario 5 - ACER)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037
LRS 2 (TS portion)	241	Coal	1/1/2042

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 8: Projected Tri-State System Resource Mix 2030 (Scenario 5 - ACER)[119, 120, 121]



[116] Commission Rule 3605(c)(I)(I).
[117] 2020 ERP Settlement Agreement at Section 3.11.8.
[118] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[119] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[120] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[121] System Energy Mix reflects sales to Members and non-Members.

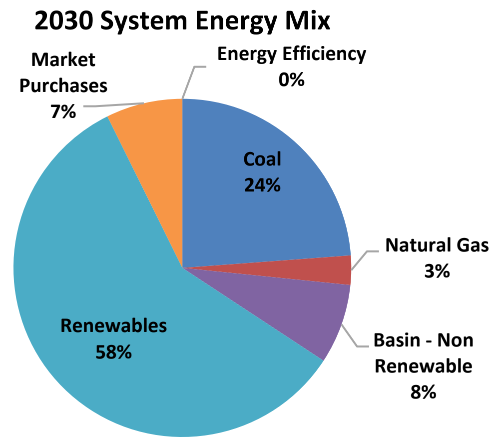


Table 89: Projected Annual Capacity Factors for Thermal Resources (Scenario 5 - ACER)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	16%	0%	0%	0%	0%	0%	0%
Craig 2	98%	9%	17%	4%	9%	0%	0%	0%
Craig 3	79%	14%	15%	11%	0%	0%	0%	0%
LRS 2	93%	89%	86%	78%	75%	71%	69%	69%
LRS 3	75%	64%	55%	48%	43%	40%	40%	45%
SPV 3	72%	67%	43%	42%	42%	36%	44%	43%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	24%	11%	1%	1%	1%	1%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	0%	0%	16%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 90: Forecasted Energy Sales and Purchases (Scenario 5 – ACER)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,508	1,506	2,719	2,521	2,453	2,347	2,911	3,587
Purchases (GWh)	352	946	641	985	803	854	1,020	776

Scenario 5 (ACER) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 91: Environmental Impact - System Wide (Scenario 5 - ACER)[122]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,841,198	7,764	10,744	0.0383	704	6,774,266,318	32,133
2025	10,919,154	5,447	6,450	0.0245	513	4,099,792,207	19,995
2026[123]	8,046,894	4,781	5,543	0.0211	393	3,336,852,935	16,657
2027	7,524,321	4,471	5,149	0.0187	359	2,957,263,352	15,143
2028	6,758,931	4,045	4,479	0.0164	340	2,603,401,641	13,418
2029	6,279,584	3,827	4,253	0.0150	303	2,351,374,862	12,230
2030	5,720,642	3,969	4,393	0.0154	340	2,617,482,127	13,065
2031	5,621,064	3,993	4,418	0.0159	364	3,205,678,404	13,331
2032	5,229,420	3,827	4,281	0.0147	330	2,990,089,809	12,392
2033	5,542,856	3,963	4,395	0.0157	357	3,162,785,437	13,164
2034	5,600,099	3,999	4,444	0.0158	359	3,185,362,689	13,291
2035	5,341,998	3,895	4,362	0.0153	335	3,057,746,388	12,644
2036	4,976,911	3,771	4,291	0.0144	297	2,858,196,567	11,765
2037	3,872,884	3,313	3,900	0.0123	197	2,353,044,102	8,984
2038	3,889,235	3,328	3,924	0.0123	197	2,350,104,263	9,021
2039	3,958,518	3,372	3,983	0.0125	199	2,378,852,575	9,176
2040	3,928,034	3,352	3,944	0.0125	200	2,381,909,167	9,114
2041	3,954,875	3,371	3,977	0.0125	199	2,380,272,599	9,172
2042	2,550,838	2,573	3,064	0.0065	119	1,575,749,975	6,087
2043	2,537,465	2,577	3,059	0.0065	118	1,562,045,832	6,084
Total	**118,094,923**	**79,640**	**93,054**	**0.316**	**6,224**	**58,182,271,249**	**256,864**
Pounds/Gallons per MWh[124]	816	0.55	0.64	0.000002	0.04	201	1.955

[122] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.
[123] Load reduced due to partial requirements contracts in 2026 forward.
[124] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 92: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 5 - ACER)

Year	Annual Social Cost of Carbon
2024	$1,391,188,757
2025	$995,703,293
2026	$762,481,386
2027	$740,668,558
2028	$690,004,358
2029	$664,696,921
2030	$627,713,272
2031	$639,644,830
2032	$616,992,472
2033	$677,908,422
2034	$709,833,808
2035	$701,607,194
2036	$677,161,912
2037	$545,789,145
2038	$567,589,551
2039	$598,133,480
2040	$614,409,701
2041	$637,343,954
2042	$427,991,342
2043	$439,003,933

Table 93: Social Cost of Methane Nominal Dollars – System Wide (Scenario 5 - ACER)

Year	Annual Social Cost of Methane
2024	$82,865,100
2025	$54,041,930
2026	$47,200,356
2027	$44,961,643
2028	$41,658,773
2029	$39,685,014
2030	$44,283,639
2031	$47,333,383
2032	$46,063,578
2033	$51,195,405
2034	$54,050,793
2035	$53,741,866
2036	$52,234,099
2037	$41,644,283
2038	$43,640,015
2039	$46,305,451
2040	$47,955,236
2041	$50,131,697
2042	$35,047,588
2043	$35,786,521

Table 94: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 5 - ACER)

Year	Target[125]	Forecast
2025	47%	47%
2026	60%	66%
2027	67.8%	73%
2028	74.2%	76%
2029	80.6%	82%
2030	87.1%	88%
2031	90%	91%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 5 (ACER) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[125] Modified targets per stakeholder-requested scenario assumptions identified in Attachment B-3, but still meets GHG reduction targets in 2020 ERP Settlement Agreement Sections 3.3.4. and 3.3.5.

Table 95: Total Financial (Scenario 5 - ACER)

$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	$17,208.2	$11,026.8	$758.1	$28,235.0	$28,993.1
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,635.9				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$623.0				

Table 96: Annual Financial (Nominal $) (Scenario 5 - ACER)

Year	Total Annual Revenue Requirement ($, Millions)
2024	$1,016
2025	$978
2026	$898
2027	$960
2028	$1,007
2029	$1,075
2030	$1,212
2031	$1,232
2032	$1,400
2033	$1,415
2034	$1,452
2035	$1,474
2036	$1,506
2037	$1,447
2038	$1,470
2039	$1,501
2040	$1,523
2041	$1,537
2042	$1,554
2043	$1,730

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 5 - ACER dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 5 – ACER are $544,004.

Table 97: Curtailed Intermittent Energy, Annual MWh (Scenario 5 - ACER)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,613	0	0	**5,613**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,955	0	0	**2,955**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**14,645**	**0**	**0**	**14,645**

Table 98: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 5 - ACER)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	85	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,767	18	170
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**110**	**12,514**	**98**	**1,923**

The following table reflects PPA pricing, penalties, and taxes.

Table 99: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 5 - ACER)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$207,282
2027	$0	$125,001
2028	$0	$102,660

2029	$0	$109,061
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$544,004**

Scenario 5 (ACER) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 100: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 5 - ACER)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind + Battery		$2.88	
2033	100	Wind		$2.88	
2033	100	Wind		$2.88	
2035	100	Wind + Battery		$2.88	
2037	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2030	290	Gas	$1.50	$4.20	
2040	100	Solar		$2.88	
2040	100	Solar		$2.88	
Wyoming (WYO) Transmission Area					
2031	100	Wind + Battery		$12.00	$109.00
2040	100	Wind + Battery		$4.20	
2040	100	Wind + Battery		$4.20	
2042	100	Wind + Battery		$4.20	$34.00
2042	100	Wind + Battery		$4.20	
2042	100	Wind + Battery		$4.20	
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					
2037	100	Wind + Battery		$2.88	$238.50
2037	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 5 (ACER) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 101: Planning Reserve Margin, % Annual (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	35%	31%	44%	47%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 102: Loss of Load Probability, Hours (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
1	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 103: Expected Unserved Energy, Annual MWh (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
2	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 5 - ACER)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 5 – ACER, 100 MW of 4-hr storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 5 (ACER) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 104 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 104: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 5 - ACER)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 105 represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 105: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 5 - ACER)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and, Level II metrics were not met in the latter part of the RAP for Scenario 5 – ACER. Scenario 5 – ACER did not meet Level 2 reliability metric thresholds:

- Six hours of LOLH in 2037 (which is beyond the three hours per year threshold); and
- Two hours of capacity lean on the market (which is beyond the zero-tolerance threshold), in the following hours and capacity amounts:
  - July 12, 2042 HE2, 40 MW; and
  - July 13, 2043 HE2, 29 MW.

Analysis of Market Purchases and Available Capacity (Scenario 5 – ACER)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 5 – ACER, the market was used for 6.4 GWh in 115 hours during the January EWE events between 2026-2031. The market was used for 12.5 GWh in 78 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase I scenarios is provided below.

Environmental Analysis

The following tables identify each scenario's system-wide forecasted CO_2 and CH_4 emissions in 2025 and 2030.

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

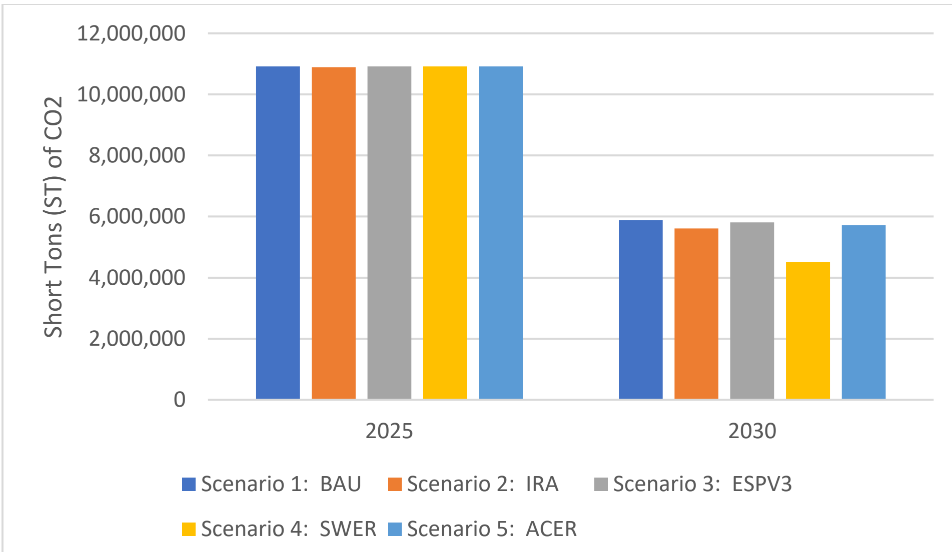
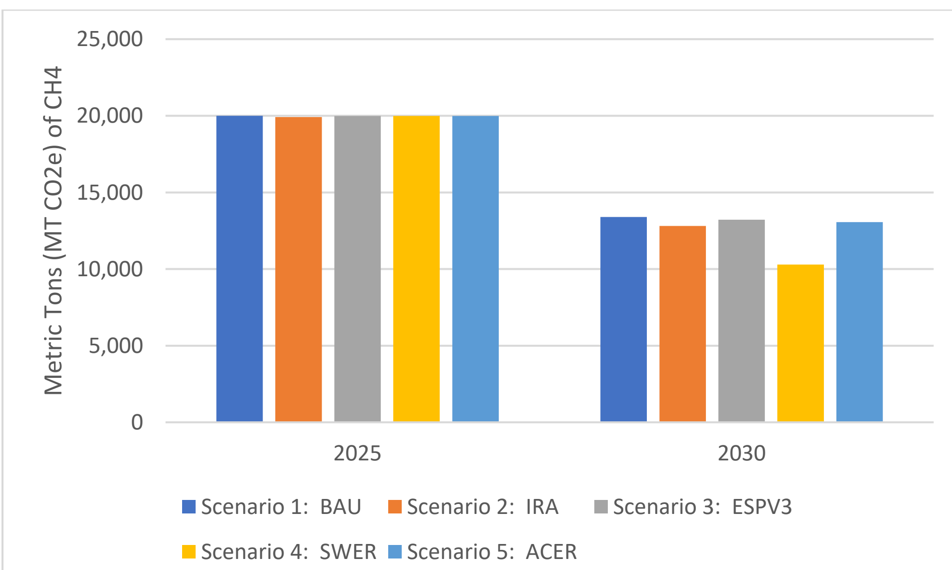


Figure 10: Comparison of Forecasted CH_4 Emissions in 2025 and 2030, by Scenario



The following table identifies each scenario's forecasted achievements toward Colorado GHG reduction targets. As shown in Figure 9 and Table 106, all scenarios achieve a consistent level of CO_2 and GHG reductions in 2025. The trend of similar GHG reductions across all scenarios holds for 2026 and 2027 as well, with the exception of Scenario 5 (ACER) achieving slightly higher reductions earlier—a result of the underlying modeling input constraint requiring minimum emissions achievements for each year of the RAP (see Attachment B-3 of the ERP Report (LKT-1). Those underlying constraints on emissions for Scenario 5 (ACER) result in significant reductions in the capacity factors for Craig 2 and LRS 3 starting in 2026 and result in the new gas plant not being utilized until 2030. Market sales are also reduced during the RAP under Scenario 5 (ACER). Notably, Scenario 2 (IRA), achieves the highest GHG reduction by 2030, 89%, as compared to the other scenarios as show in Table 106 and Figure 11.

Additional discussion of Tri-State's consideration of the environmental results of the scenario analyses can be found in the Executive Summary; and in the Financial Analysis section below, which scenario identifies PVRRs with SCoC and SCoM.

Table 106: Comparison of Scenario Achievements Toward Colorado GHG Reduction Targets

	2025	2026	2027	2030
Scenario 1: BAU	47%	60%	68%	86%
Scenario 2: IRA	47%	60%	67%	89%
Scenario 3: ESPV3	47%	60%	67%	85%
Scenario 4: SWER	47%	60%	68%	82%
Scenario 5: ACER	47%	66%	73%	88%

Figure 11: Comparison of Scenario Achievements Toward Colorado GHG Reduction Targets

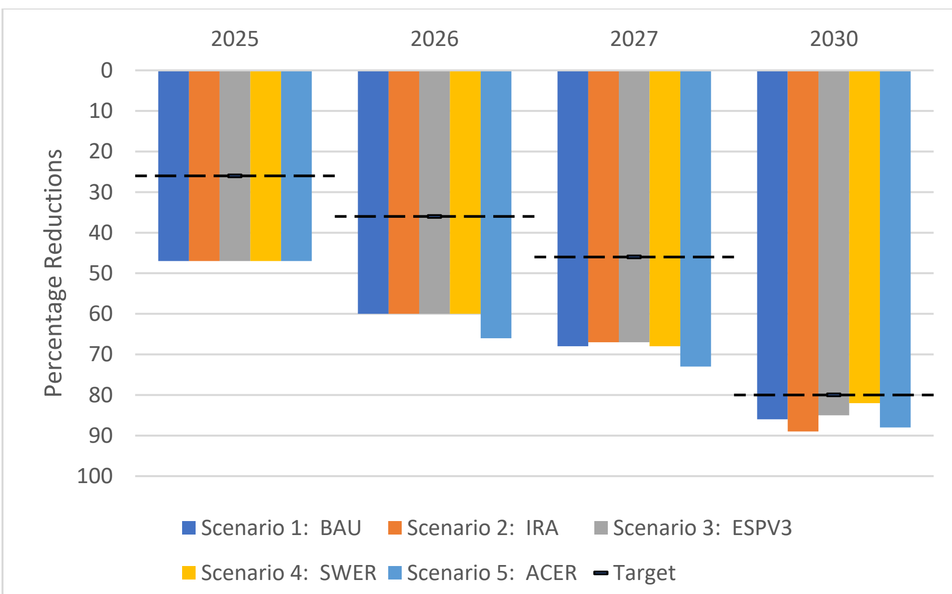


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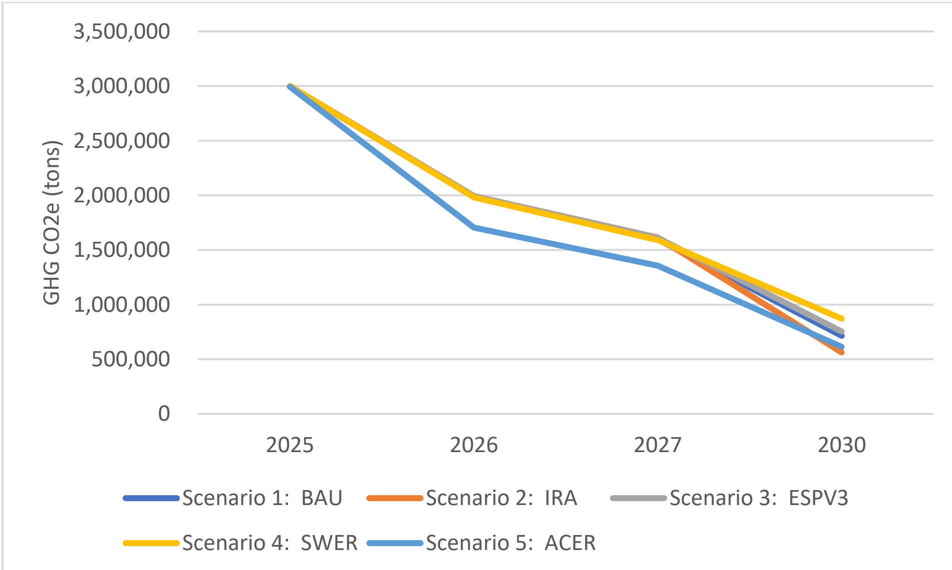
Figure 12: Comparison of Colorado CO2e



As shown in Figure 13 below, there is little deviation in the annual SCoC across the scenarios modeled, until after 2030. Scenario 1 (BAU) and Scenario 5 (ACER) have fairly similar SCoC levels in the early 2030s as Colorado greenhouse gas reduction levels are similar (roughly a 2 percent difference) in 2030; and from 2024 to 2033 the primary differences between the two scenarios being the timing of new resource additions. Neither Scenario 1 (BAU) or Scenario 5 (ACER) retires SPV 3 in the first ten years of the RPP. Scenario 2 (IRA) achieves a lower SCoC due to more renewable resources being added during the RAP, as well as the early retirement of SPV3. Scenario 3 (ESPV3) also results in lower levels of SCoC due to retirement of SPV 3 during the RAP. Scenario 4 (SWER) sets minimum system-wide emission reductions as underlying modeling input constraints, which result in the lowest SCoC levels across the scenarios. Similar trends across the scenarios are seen in Figure 14 below, for SCoM.

Figure 13: Comparison of SCoC

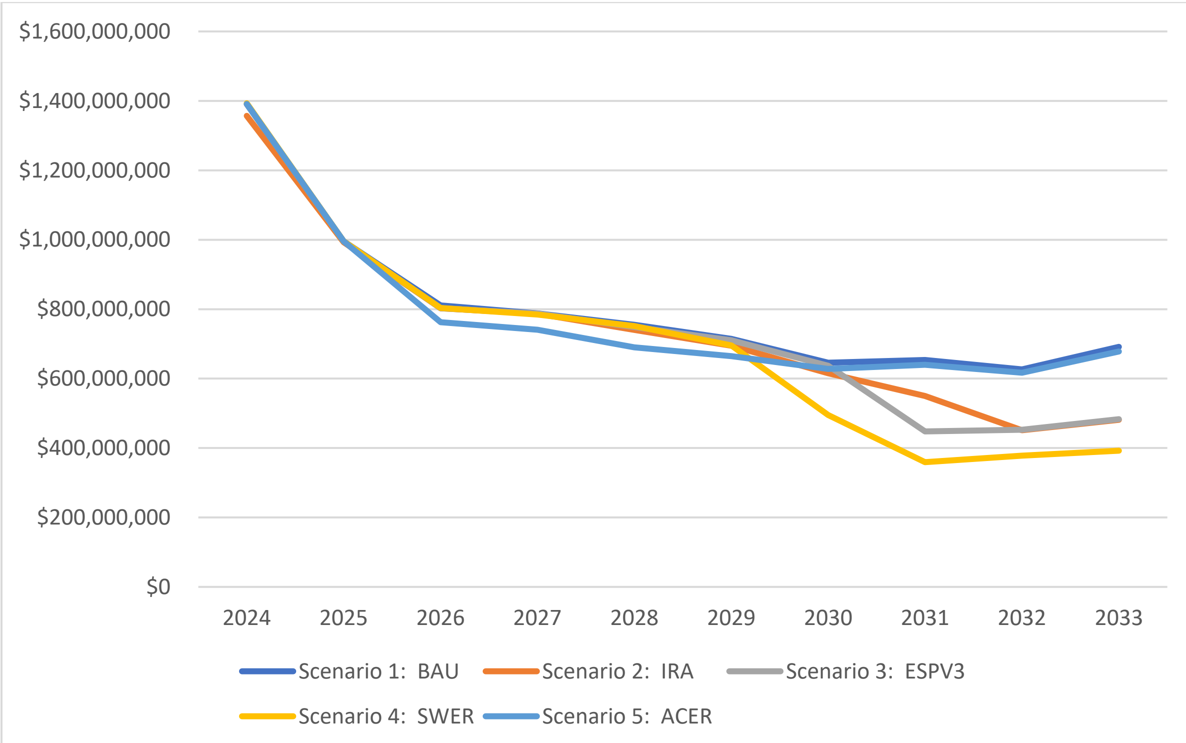
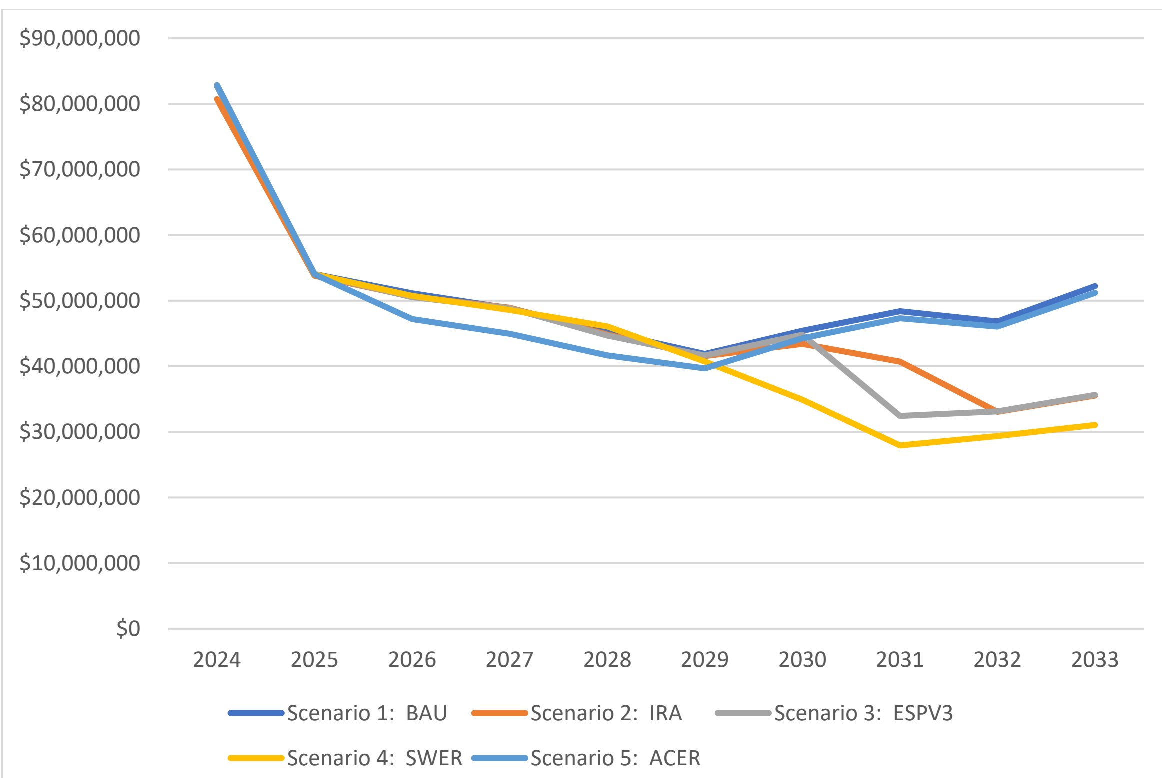


Figure 14: Comparison of SCoM



Financial Analysis

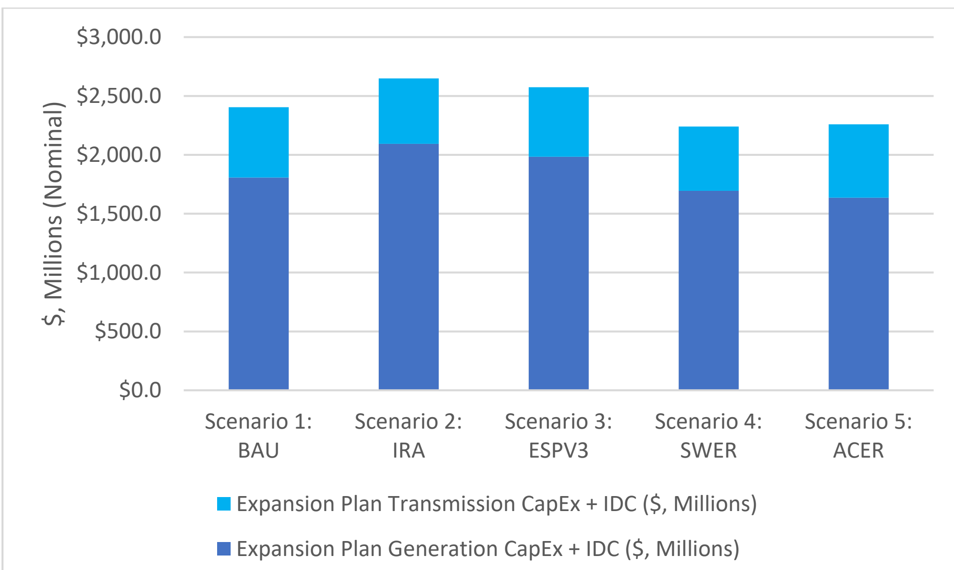
The following table compares total financial results for each scenario, both with and without the SCoC and SCoM. Scenario 2 (IRA) is the lowest cost plan on a PVRR basis. Scenario 2 (IRA) also has the lowest PVRR when SCoC and SCoM are included. Scenario 2 (IRA) exceeds Colorado GHG reduction target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

Table 107: Comparison of PVRR

	PVRR ($, Millions)	PVRR w/SCoC and SCoM ($, Millions)
Scenario 1: BAU	$17,507.4	$29,916.4
Scenario 2: IRA	$16,352.0	$27,811.8
Scenario 3: ESPV3	$17,304.2	$28,828.6
Scenario 4: SWER	$17,343.9	$27,922.2
Scenario 5: ACER	$17,208.2	$28,993.1

Figure 15 below compares capital expenditures for resource additions and transmission interconnection and upgrades by scenario over the RPP. While the Scenario 2 (IRA) results in comparatively higher CapEx, the overall financial impact of the scenario is the lowest due to New ERA funding being pursued by Tri-State for the benefit of its Members.

Figure 15: Comparison of Generation and Transmission CapEx (Nominal $)



As shown in Table 108 below, all scenarios selected a 290 MW gas plant during the RAP (in 2028, 2029, or 2030), with conversion to CCS in 2031, and selected some amount of wind hybrids. All scenarios include 140 MW of solar to replace the Coyote Gulch PPA that was terminated in 2023. Scenario 1 (BAU) and Scenario 3 (ESPV3) have similar levels of MWs and resource additions during the RAP. Scenario 4 (SWER) and Scenario 5 (ACER) have similar levels of MWs and resource additions. Scenario 2 (IRA) selects 1,400 MW of resources during the RAP, in addition to the 140 MW of replacement solar, more than double the total resource additions in Scenario 4 (SWER) and Scenario 5 (ACER) and significantly higher than the total resource additions in Scenario 1 (BAU) and Scenario 3 (ESPV3). The increase in resource selection during the RAP in Scenario 2 (IRA) is due to potential federal funding being available only through the RAP period. The funding would allow Scenario 2 (IRA) to bring on more resources during the RAP while improving affordability, maintaining reliability, and making strides toward evolving environmental requirements.

Table 108: Comparison of MW Additions by Scenario, by Technology over the RAP

	Scenario 1 – BAU	Scenario 2 – IRA	Scenario 3 – ESPV3	Scenario 4 – SWER	Scenario 5 – ACER
Wind	0	500	0	0	0
Solar	140	240	140	140	140
Standalone Storage	100	210	200	0	0
Gas	290	290	290	290	290
Wind Hybrid	300	200	300	100	200
Wind Hybrid – Battery Storage Component	150	100	150	50	100
RAP Total	**980**	**1,540**	**1,080**	**580**	**730**

Note: Wind Hybrid components share interconnect.

Table 109 below identifies the percentage of generation capacity that is intermittent or dispatchable/firm, and the percent of system energy that is renewable for each scenario in 2030. Scenario 2 (IRA) yields the highest percentage of renewables in terms of system energy mix in 2030, while maintaining a reasonable mix of intermittent and dispatchable/firm capacity at 39 percent and 54 percent, respectively.

Table 109: Comparison of Renewables, Intermittent and Dispatchable Resources in the 2030 Mix, by Scenario

	2030 Generation Capacity Mix, % Intermittent	2030 Generation Capacity Mix, % Dispatchable/Firm	2030 System Energy Mix, % Renewables
Scenario 1: BAU	34%	59%	59%
Scenario 2: IRA	39%	54%	64%
Scenario 3: ESPV3	34%	61%	58%
Scenario 4: SWER	33%	61%	61%
Scenario 5: ACER	34%	61%	58%

Note: Capacity from energy efficiency / demand response and semi-dispatchable resources are not reflected in either the intermittent or dispatchable/firm, therefore the sum of the capacity mix percentages does not total 100%.

Curtailments

The following tables identify the annual PPA curtailment costs (pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type.

Table 110: Comparison of Wind PPA Curtailment Costs by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
2024	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0
2026	$0	$0	$0	$0	$0
2027	$0	$0	$0	$0	$0
2028	$0	$0	$0	$0	$0
2029	$0	$0	$0	$0	$0
2030	$0	$0	$0	$0	$0
2031	$0	$8,765	$2,511	$0	$0
RAP Total	**$0**	**$8,765**	**$2,511**	**$0**	**$0**

Table 111: Comparison of Solar PPA Curtailment Costs by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
2024	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0
2026	$208,078	$2,816	$208,309	$216,270	$207,282
2027	$125,060	$0	$124,914	$126,321	$125,001
2028	$102,674	$9,596	$102,651	$106,117	$102,660
2029	$82,738	$122,947	$82,570	$82,658	$109,061
2030	$0	$29,692	$0	$0	$0
2031	$0	$329,902	$0	$0	$0
RAP Total	**$518,550**	**$494,953**	**$518,444**	**$531,366**	**$544,004**

Scenario 4 (SWER) and Scenario 5 (ACER) have the highest curtailment costs compared to the other scenarios. Scenario 2 (IRA) has the lowest curtailment costs while still achieving the highest GHG reduction in Colorado by 2030.

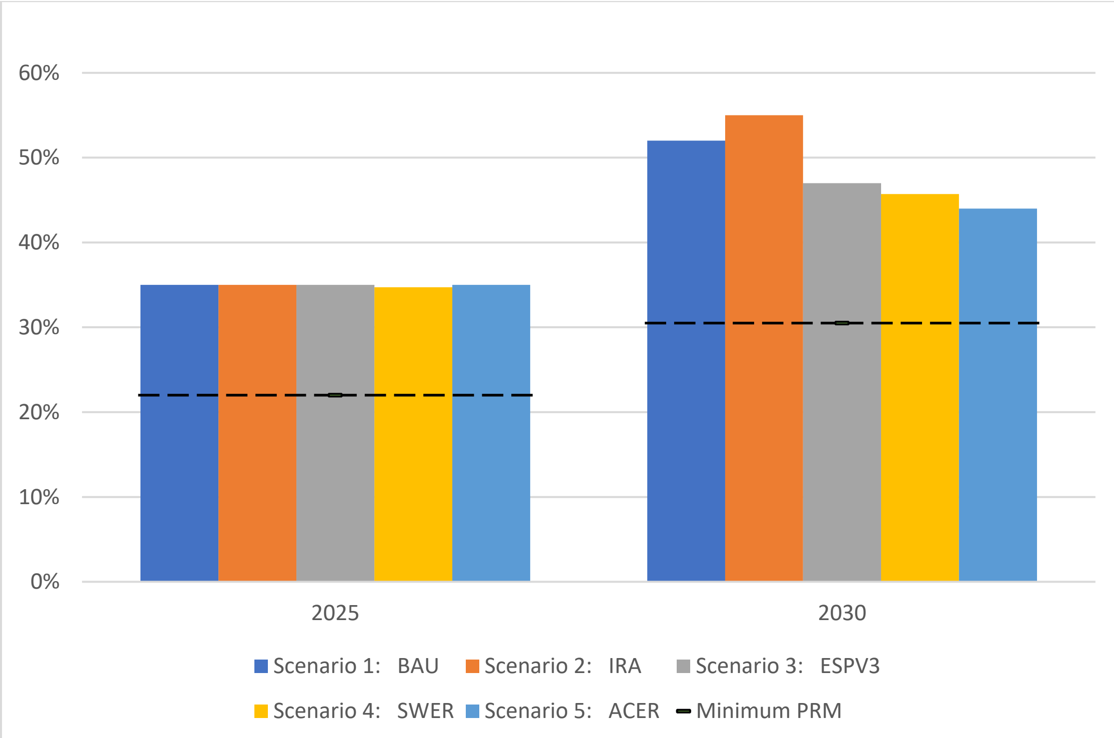
Table 112: Comparison of Total Wind + Solar Curtailment Costs during the RAP, by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
RAP Total	$518,550	$503,718	$520,955	$531,366	$544,004

Reliability Analysis

PRMs were relatively consistent across all scenarios through 2027. PRMs in 2030 range from 44 percent to 55 percent. The level of resource additions enabled by potential New ERA funding in Scenario 2 (IRA) resulted in higher PRMs during the RAP as compared to other scenarios.

Figure 16: Comparison of PRMs During the RAP



Each of the scenarios were able to meet Level I and II reliability metrics during the RAP. Scenario 2 (IRA) is the scenario that results in the greatest certainty in achieving reliability in the most cost-effective manner because it allows for the acquisition of more resources earlier in Tri-State's planning period. Tri-State's PRMs stay well above requirements, allowing for potential procurement or operational delays to more likely be addressed without reliability issues.

Conclusion

Given the comprehensive and thorough data obtained on the multiple scenarios modeled, the ERP Report supports approval of the IRA Scenario as Tri-State's preferred plan. As such, Tri-State requests the Commission: (1) find that the IRA Scenario within Tri-State's ERP Application meets the applicable rule requirements, (2) approve the IRA Scenario as Tri-State's Phase I preferred plan, and (3) approve Tri-State's Phase II procurement plans in this proceeding.

List of Tables and Figures